THE IMPORTANCE OF THE GAS INFRASTRUCTURE FOR GERMANY’S ENERGY TRANSITION

A model-based analysis

January 2018

(English convenience translation of German report “Der Wert der Gasinfrastruktur für die Energiewende in Deuschland”)

A study on behalf oft he Vereinigung der Fernleitungsnetzbetreiber (FNB Gas e.V.).

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LIST OF ABBREVIATIONS

CCS	Carbon capture and storage
CH_4	Methane
CO_2	Carbon dioxide
DSM	Demand side management
DLR	Deutsches Zentrum für Luft- und Raumfahrt (German Aerospace Center)
RES	Renewable Energy Source
EnLAG	Energieleitungsausbaugesetz (Energy Line Extension Act)
TCS	Trade, commerce and services
H_2	Hydrogen
HVDC	High-voltage direct current
HH	Households
EHV	Extra-high voltage
HV	High voltage
LNG	Liquefied natural gas
MV	Medium voltage
NABEG	Netzausbaubeschleunigungsgesetz (Network Expansion Acceleration Act)
NDP	Network development plan
NIMBY	Not in my backyard
LV	Low voltage
$PtCH_4$	Power-to-methane
PtG	Power-to-gas
PtGtP	Power-to-gas-to-power
PtH_2	Power-to-hydrogen
PtL	Power-to-liquids
PV	Photovoltaic
GHG	Greenhouse gas
TYNDP	Ten-Year Network Development Plan
UBA	Umweltbundesamt (Federal Environment Agency)
TSO	Transmission system operator

EXECUTIVE SUMMARY

Question: What sustainable contribution can gas infrastructure make to the future energy system based on renewable energy?

Germany has set itself ambitious climate protection targets: by 2050, greenhouse gas emission levels are to be reduced by 80 to 95 per cent as compared to 1990. A clear policy requirement in this process is that the majority of the greenhouse gas reduction be achieved using renewable electricity in the heat, transport and industrial sectors. The question as to how energy should be transported from where it is produced to the end-consumer as well as how it should be stored remains unresolved, particularly in terms of what role gas infrastructure will play in future. Today, the annual consumption of gas in Germany – dominated by natural gas and with only a small share of biogas – is 601 TWh, equivalent to around 24 per cent of the country's overall final energy requirements. In the heat sector, gas accounts for as much as 45 per cent of final energy requirements.

Against this backdrop, the Association of German Gas Transmission System Operators (FNB Gas e.V.) has commissioned Frontier Economics, IAEW, 4 Management and EMCEL to evaluate the cost impact on the energy system of the long-term ongoing use of the gas infrastructure to transport gas produced from renewable energy ("green gas"). The analysis focusses on the year 2050.

Scenarios: Comparison of 2050 energy systems with and without the use of gas infrastructure

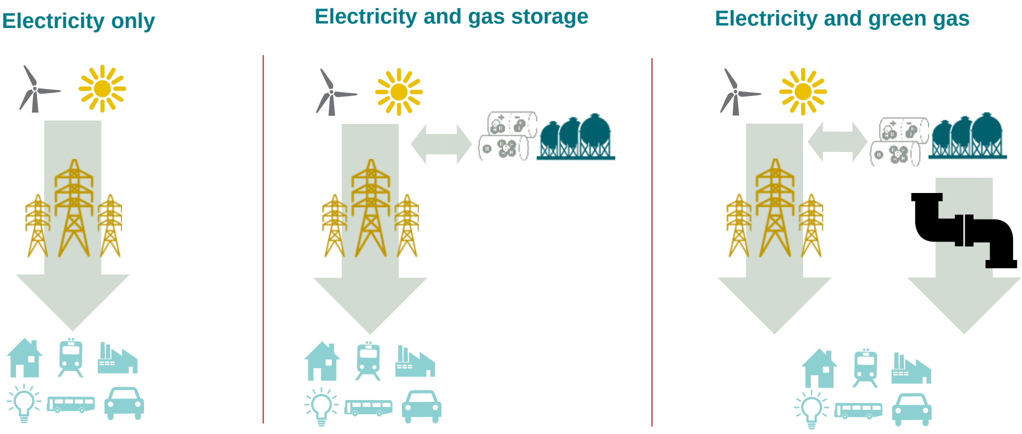
The analysis focuses on three scenarios for 2050 (**Figure 1**):

- **"Electricity-only"** – End-consumers primarily use electrical end-user applications such as heat pumps and electric cars for their heat and transportation needs ("Direct electrification"). The connection between energy generation and final energy use is only made by electricity networks and electricity storage systems (hence the name "Electricity-only"). In this scenario, the gas infrastructure (including storage systems and pipelines) is therefore no longer required in the long term.
- **"Electricity and gas storage"** – As with the "Electricity-only" scenario, end-consumers primarily use electrical end-user applications. Storage, however, is not based exclusively on the storage of electricity: there is also the option of converting electrical energy to gas, temporarily storing the gas and later converting the gas back to electricity using gas fired power plants ("power-to-gas-to-power" or PtGtP). Energy transportation from energy generation to final energy use is still based on electricity. Gas transportation and distribution networks – unlike gas storage systems – are no longer required in this scenario.
- **"Electricity and green gas"** – In this scenario, some end-user applications are based on green gas, which is generated synthetically in German power-to-gas (PtG) plants from renewably generated electricity ("Indirect

electrification"). Accordingly, in parallel to the electricity network, the existing gas infrastructure will remain in use for energy transportation.

To ensure comparability, all scenarios assume compliance with Germany's ambitious climate targets, with a 95 per cent reduction in greenhouse gas emissions compared to 1990, which ultimately requires the electricity, heat and transport sectors to become almost completely carbon-neutral. All scenarios also assume the same end-use energy demand (i.e. energy ultimately consumed) although different conversion efficiencies in end-user applications (gas v. electricity) mean that the final energy demand differs by scenario.

Figure 1 Summary of the three scenarios considered



Source: Frontier Economics

Result: Use of the gas infrastructure reduces decarbonisation costs and increases the acceptance and security of supply of the energy transition

Green gas delivered using the gas infrastructure allows Germany to reach its climate protection goals

Green gas – either produced synthetically from renewable sources (power-to-gas) or naturally from biogas – can make a valuable contribution to Germany reaching its ambitious climate protection goals. It is important to understand here that while the final use of green methane produces CO_2 emissions, this same amount of CO_2 will have previously been extracted from the environment during the production of the synthetic gas, resulting in a CO_2 -neutral cycle of producing and using green gas. This synthetic gas therefore has the same beneficial climate properties as biomass or biogas.

The climate protection goals to reduce greenhouse gas emissions by 95 per cent by 2050 as compared to 1990 levels – or even by 99 per cent in the case of the energy, transport and heat sectors – are fully met by all scenarios alike. The form of end user energy consumption (i.e. whether the consumer is supplied with energy in the form of electricity or with gas in the form of green gas) is irrelevant in terms of the climate impact.

> Whether consumers are supplied with renewable energy as electricity or green gas is irrelevant when it comes to climate impact!

Supplying energy to consumers in winter and during cold, dark periods with low wind is not achievable unless energy is stored in gas storage systems

Tremendous challenges in supplying electricity to end consumers would emerge with the electrified provision of heat provision, given the very high seasonal differences in heat demand. A further challenge in supplying electricity from renewable sources results from the dependency of such electricity on the availability of wind and sun. Electricity storage devices such as pumped hydro storage power plants or batteries can only store energy temporarily and in small quantities. Therefore, an "all-electric" world without the use of gas storage – at least for seasonal storage and for providing energy during cold, dark periods with low wind – would be prohibitively expensive and unrealistic.

Other recent studies support this view, such as Enervis (2017) or Energy Brainpool (2017). A rough calculation for Germany[1] shows that electricity storage systems with a storage volume of around 35 TWh are required for near-complete decarbonisation via direct electrification. In comparison, the current storage volume of all electricity storage systems in Germany (mainly in pumped hydro storage power plants) is around 0.04 TWh. It would therefore take more than 800 times the current electricity storage volume to manage the seasonality of heat demand and bridge the supply – demand gap for electricity.

The purpose of this study is therefore not to demonstrate the fundamental need – now almost universally acknowledged – to store gas on a seasonal basis as a reservoir of energy by comparing the scenarios with gas storage to the "Electricity-only" scenario. Rather, it is to analyse the potential contribution that transporting energy from energy generation to its final use through gas networks can make, in addition to the contribution of gas simply serving as a form of temporary storage. Consequently, the analysis focuses on comparing the "Electricity and gas storage" and "Electricity and green gas" scenarios.

> An "Electricity-only" scenario without any gas storage is not a realistic option for the energy transition

[1] This assumes complete decarbonisation and electrification of a large proportion of final energy demand, with electricity supplied by equal capacities of on-shore wind, off-shore wind and solar power.

Use of green gas by end-consumers significantly reduces system costs by avoiding the expansion of the electricity network and providing savings in end-user applications

Our analysis shows that the continued use of the gas transportation and distribution networks to supply consumers with green gas ("Electricity and green gas" scenario) offers further cost savings compared to a world in which the gas networks are no longer used ("Electricity and gas storage" scenario).

By 2050, overall net savings will amount to around EUR 12 billion per year (in real terms, expressed as 2015 values). These savings include avoiding the need to invest in electricity networks and end-user applications of approximately EUR 268 billion by the year 2050 (without discounting future costs).

> Using gas networks will save EUR 12 billion per year by 2050

Based on analysis using comprehensive electricity market and electricity network models, we have estimated the impact over the entire energy supply chain of using the gas network for green gas. In other words, we have considered the impact of using the gas network on the costs of electricity production, energy conversion, electricity and gas transportation, electricity and gas storage, and end-user applications.

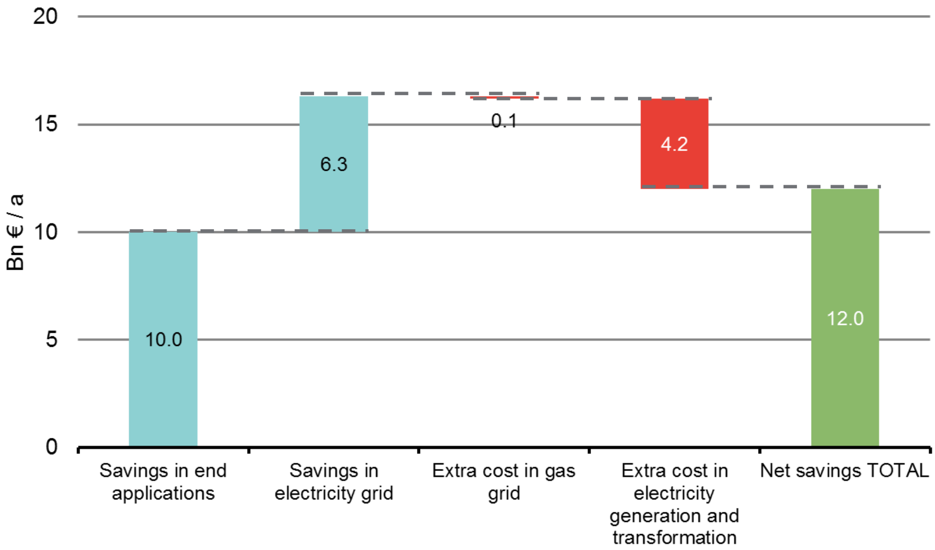
Figure 2 illustrates that the total net cost savings (EUR 12 billion per year) of using the gas network comprise:

- lower costs for gas-based end-user applications (EUR 10 billion per year saving by 2050), especially in the heating sector; and
- savings from significantly lower electricity network expansion requirements (EUR 6.3 billion per year saving by 2050) as a consequence of using the gas network.

These savings of EUR 16.3 billion per year by 2050 significantly outweigh additional costs generated elsewhere, that is:

- for the retention and partial conversion of the gas networks (EUR 0.1 billion per year of additional cost by 2050) as opposed to a decommissioning of downstream gas infrastructure; plus
- for additional electricity generation and power-to-gas plants required due to energy conversion losses (EUR 4.2 billion per year of additional costs by 2050).

Figure 2 Annual system net cost savings in the "Electricity and green gas" scenario compared to the "Electricity and gas storage" scenario (by 2050)



Source: Frontier Economics

Note: The per annum costs are shown in EUR2015 for the year 2050.

Use of gas infrastructure substantially reduces the need for electricity network expansion and thus significantly boosts public acceptance of the energy transition

Public acceptance of additional energy infrastructure for the energy transition already poses a challenge and this will be exacerbated significantly over time. Although the expansion of renewable energy is still perceived as largely positive, efforts to expand electricity networks encounter significant local opposition. This has led to severe delays in the expansion of electricity transportation networks. Moreover, the German public has not yet taken on board the fact that electricity distribution networks need to be expanded substantially further in the next few years.

The use of the existing gas transport infrastructure represents an alternative to expanding the electricity network. Our electricity network models show that using the gas networks avoids the need to expand the electricity network by 17,800 kilometres of transmission lines (compared to 35,000 kilometres of lines today, including the implementation of all electricity Network Development Plan measures in both scenarios) and by 500,000 kilometres of distribution lines (as compared to 1.7 million kilometres of lines today). Since gas networks already exist and have been built underground, they can significantly boost acceptance of the energy transition.

> "
> Using gas networks reduces the expansion of the electricity transmission network by around 40 per cent and the electricity distribution network by 60 per cent

Inclusion of gas networks contributes significantly to the energy system's security of energy supply

Ongoing use of existing gas networks provides access to the international gas transportation network and thus also to international gas sources and storage systems, including green gas sources located overseas. This preserves the existing deep integration of the German energy supply with that of other countries, thereby continuing to provide the high levels of security of supply that German consumers expect, since bottlenecks in the delivery of energy in individual regions can be managed by the use of diversified supply sources.

> Use of green gas can also help diversify energy sources

It's unclear whether the international exchange of gas would only be used to safeguard against critical supply situations or whether green gas could be used as a way to import renewable energy from other countries or to export surplus electricity. Consequently, retaining the gas infrastructure could mean that green gas sources of supply with far lower production costs for the German market become available. The analysis of costs shown above is based on a conservative assumption that all of the green gas required will be produced in Germany. A less conservative assumption would see the costs of the "Electricity and green gas" scenario slashed.

The continued use of the existing gas infrastructure, including existing gas storage systems, also extends the range of extensive storage options available for energy generated from renewable sources, further supporting security of supply.

1 QUESTION: HOW CAN THE GAS INFRASTRUCTURE CONTRIBUTE TO THE ENERGY TRANSITION?

Against a backdrop of politically intended near-total carbon-neutrality by 2050, the Association of German Gas Transmission System Operators (FNB Gas e.V.) commissioned Frontier Economics, IAEW, 4 Management and EMCEL to evaluate the added value of continuing to use the gas infrastructure in future for green gas.

1.1 Background: Sector coupling means the energy transition affects all energy consumption sectors, presenting new challenges for the transport and storage of energy

The German Federal Government has set far-reaching goals to reduce greenhouse gas emissions ("GHG") by 2050. Compared to 1990, GHG emissions are to be reduced by 80 to 95 per cent by 2050. While the energy transition currently emphasises switching power generation to renewable energy sources, the ambitious climate protection goal to reduce emissions by 95 per cent also requires an energy transition in other sectors, particularly heat, transport and industry.

As well as avoiding energy consumption ("efficiency first") and directly exploiting renewable energy such as biomass and solar energy (despite limited potential to do so in Germany), a process known as "sector coupling" will be used as the primary means of achieving the reduction in emissions in other sectors. Via this process, the energy consumption in sectors previously dominated by fossil fuels, such as heat (natural gas and heating oil) and transport (primarily mineral oil), will be switched to renewably produced electricity.

The public debate among experts is increasingly reaching consensus over the fact that this form of sector coupling is the proper and necessary solution to achieve ambitious climate goals. However, the question remains as to which energy transport infrastructure will be used in future to establish the connection between renewably generated electricity and energy consumers and, in particular, what role the gas infrastructure will play going forward.

1.2 Approach: Analysing the effects of different energy transport scenarios on the entire energy system supply chain

In 2050, the gas infrastructure will no longer be used to transport and store natural gas but green gas (above all "power-to-gas").

In this context, the question arises as to whether and in what form the existing gas infrastructure can meaningfully contribute to the future energy system. Different analysis of how to achieve the ambitious climate protection goals has clearly shown that fossil natural gas will ultimately play no significant role in the energy supply in 2050.[2,3] The existing gas infrastructure – in other words the system comprising long-distance gas pipelines, storage systems, regional pipelines and distribution networks – can, however, remain in use in future to transport and store so-called "green gas". Green gas is primarily defined as that produced via renewable electricity ("power-to-gas" or PtG).[4]

The use of green gas is climate-neutral, as is the case when using biomass. Hydrogen generates no CO_2 emissions upon combustion. Even when synthetic methane is used, the volume of CO_2 released upon combustion is exactly the same as the CO_2 absorbed from the environment during the production of the synthetic methane.

This study analyses the extent to which the gas infrastructure – the gas storage systems as well as the transmission and distribution networks – can play a key role in complete decarbonisation, in terms of promoting social acceptance, maintaining security of supply and reducing costs.

Analysis of the role of the gas infrastructure on system costs

We analyse and compare system costs for scenarios that differ in the degree to which the gas infrastructure continues to contribute to the transport of energy in 2050.

The comparison of system costs focuses on Germany in 2050 and takes into consideration all major costs along the entire energy supply chain (**Figure 3**), including:

- **End-consumers** – At this stage of the energy supply chain, the costs of the end-user applications for final energy use are taken into account. In this case, we focus on the differences between the scenarios in terms of costs incurred by customers when purchasing heat applications and vehicles.
- **Transportation and distribution of electricity** – Using network models, we estimate the different expansion and maintenance requirements on

[2] This situation, however, could change if the option of comprehensive carbon capture and storage (CCS) were to play a role in future. This study assumes that this will not be the case in Germany.

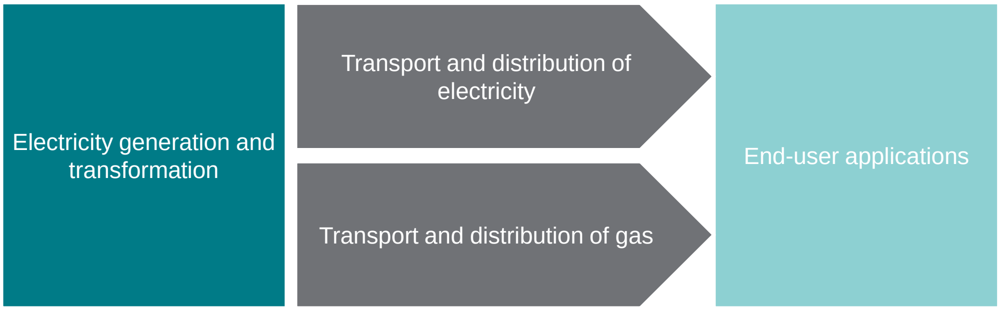
[3] As a bridge technology, however, fossil natural gas can still make a major contribution towards completely decarbonising the energy system.

[4] Green gas also includes biogas. We have abstracted from this in our calculations for simplicity (as potentials in Germany are limited anyway).

transportation and distribution networks for electricity for each scenario and determine the corresponding cost implications.

- **Transportation and distribution of gas –** The costs of adapting, expanding and maintaining the transportation and distribution networks for green gas are taken into account for each scenario, as well as the costs of potentially dismantling any existing gas infrastructure no longer in use.
- **Generation and conversion of electricity –** Here, we used a comprehensive electricity market simulation to estimate the costs of generating and storing electricity as well as of converting the electricity to gas in power-to-gas plants.

Figure 3 Determination of costs along the entire energy supply chain



Source: Frontier Economics

To take account of both ongoing and one-off costs and to compare investments with different technical and economic lifespans, we express the costs of one-off investments as an annuity and present annual costs as the primary result .

These costs, however, are not one-off, but recur annually. The actual respective costs in the years before or after 2050 cannot be accurately determined on a year-by-year basis, given the variation in individual cost items over time (e.g. the purchase costs of end-user devices). Thus, the respective costs are referred to as "annual costs by 2050". All annual values are shown in real terms, expressed as 2015 EUR values. Wherever possible and reasonable, aggregated cost values for the period up until 2050 are also shown (then undiscounted).

2 SCENARIOS: COMPARISON OF WORLDS WITH AND WITHOUT THE USE OF GAS INFRASTRUCTURE

SUMMARY

The question as to which energy system will emerge during the energy transition is very complex and depends on many economic, political and technical conditions and developments. Of course, a wide range of developments are possible, not least because of the uncertainties associated with the long timeframe for the analysis (until 2050). With practicality in mind, the scope of this study cannot cover the entire range of options, but must focus on a limited number of scenarios.

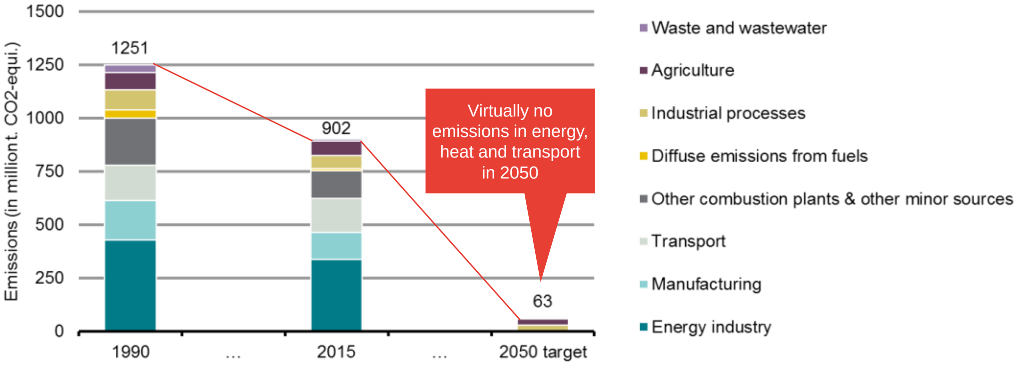
As a result, three scenarios for the year 2050 have been selected that enable the importance of the gas infrastructure for the energy transition to be determined based on a comparison of the scenarios:

- In all scenarios it is assumed that the ambitious climate goals to reduce GHGs by 95 per cent will be met by 2050 (**Section 2.1**).
- However, the scenarios differ fundamentally in the degree to which the gas infrastructure can continue to be exploited in 2050 (**Section 2.2**);
  - Only the "Electricity and green gas" scenario assumes the continued presence of a gas infrastructure linking energy generation to its final use that is capable of supplying gas-based end-user applications over the long run. As a result of different conversion efficiencies between gas and electricity end user applications, the scenarios have differences in final energy demand (**Section 2.3**). With "Electricity and green gas", the widespread use of power-to-gas technology (PtG, i.e. the production of "green gases" from renewable electricity) would be required.
  - Alternatively, the "Electricity and gas storage" scenario is also considered, whereby PtG is only used for temporary storage and gas is later converted back into electricity (**Section 2.4**).
  - The "Electricity-only" scenario, in which PtG plays absolutely no role, is also considered. The "Electricity and gas storage" and "Electricity-only" scenarios see energy transported to consumers only in the form of electricity, whereas the "Electricity and green gas" scenario calls for the simultaneous use of electricity and gas networks (**Section 2.5**).

2.1 All scenarios achieve Germany's 95 % climate goals by 2050

The key assumption made in our analysis is that the use of the gas infrastructure will not compromise decarbonisation in any way. All analysis for all scenarios assumes the realisation of German's ambitious targets with the successful reduction of greenhouse gas emissions by 95 per cent by 2050 compared to 1990.[5] Considering that it is very difficult to reduce greenhouse gas emissions in industrial processes and in agriculture, this goal will see the near-complete decarbonisation of the energy, heat and transport sectors.[6] In this scenario, fossil fuels such as coal, crude oil and natural gas can no longer be used (to any significant extent) to generate electricity, to supply heat or to fuel transport.

Figure 4 Greenhouse gas emissions in Germany in all scenarios



Source: Frontier Economics (historical values based on information from the Federal Environmental Agency: National greenhouse gas inventory 2017, final status 04/2017).

2.2 Scenarios use gas infrastructure to different degrees

With regard to the question underlying this study, the three scenarios considered differ in particular with regard to the degree to which the gas infrastructure can be used for the supply of energy. Our analysis centres on the following three scenarios for 2050 (**Figure 5**):

- **"Electricity-only"** – In this scenario, end consumers primarily use electrical applications such as heat pumps and electric cars ("direct electrification"). The connection between energy generation and final energy use is only made by electricity networks and electricity storage systems. The existing gas infrastructure comprising gas pipelines and storage facilities is no longer required and must accordingly be decommissioned, secured and partially dismantled.
- **"Electricity and gas storage"** – In this scenario, the "Electricity-only" scenario is expanded to include the potential to convert electrical energy to gas, temporarily store the gas and later to convert the gas back into electricity using gas fired power plants ("power-to-gas-to-power" or PtGtP). As with "Electricity-only", in this scenario, only electricity networks are used to transport energy to consumers from generation to final use. This means that

[5] For all other European countries, we assume that the greenhouse gases are reduced by 80 per cent in the electricity sector.

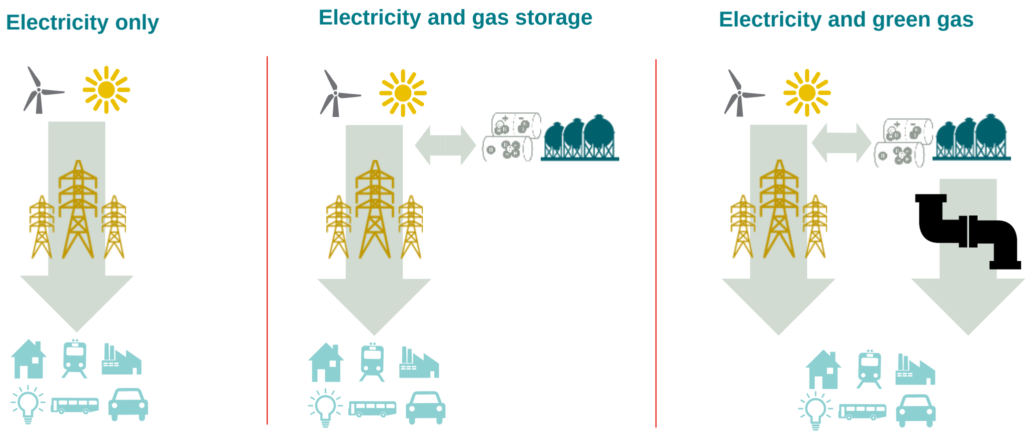
[6] For the energy, heat and transport sectors, it is assumed that greenhouse gases will be reduced by 99 per cent by 2050 as compared to 2015.

gas transportation and distribution networks can largely be left disused and must accordingly be decommissioned, secured and partially dismantled.

- **"Electricity and green gas" –** In this scenario, some end-user applications are based on green gas, which is generated synthetically in German power-to-gas (PtG) plants. Accordingly, and in parallel to the electricity network, the existing gas infrastructure will remain in use to transport energy.

The scenarios each have assumptions about the final energy demand which must be supplied to consumers through the energy system. They each also have assumptions about the technological options available to fulfil the supply task, particularly regarding energy transportation and conversion.

Figure 5 Schematic overview of the three scenarios



Source: Frontier Economics

Figure 6 summarises the key features of each of the three scenarios, with the features and assumptions explained in further detail in subsequent sections.

Figure 6 Key features of the three scenarios considered

	Electricity-only	Electricity and gas storage	Electricity and green gas
End applications	▪ Most end-user applications directly electrified (e.g. e-vehicles, heat pumps, direct heating systems) ▪ No gas-based end-user applications	▪ End-user applications the same as for the "Electricity-only" scenario	▪ Some of the end-user applications directly electrified (e.g. e-vehicles or heat pumps in new buildings) ▪ Partly based on green gas (e.g. gas boiler or gas-based vehicle)
Power-to-gas	▪ No PtG	▪ Possibility to store renewably generated electricity in the form of gas via PtG temporarily, then feed it back to power plants ("power-to-gas-to-power" or PtGtP). ▪ Helps to smooth out seasonality of final electricity consumption, particularly in the heating sector, and supply electricity during dark periods with little wind	▪ Additional possibility for PtGtP ▪ Furthermore, green gas used for end-user applications must be synthetically produced in PtG plants in Germany ▪ Assumption that 50 per cent of the green gas is directly transported and used as H_2 (PtH_2) in the transport and industry sectors), while the remaining half is converted to methane ($PtCH_4$) and transported via distribution networks to heat consumers
Energy transport	▪ Connection between energy generation and final energy use only through electricity networks and electricity storage systems ▪ Gas infrastructure no longer required (with the exception of transit pipelines)	▪ Connection between energy generation and final energy use only through electricity networks ▪ Use (of a portion) of the gas storage (for PtGtP) ▪ Gas transport and distribution networks not used (with the exception of transit pipelines and pipelines between PtG plants, gas storage systems and gas power plants)	▪ Continued use of the gas infrastructure (and partly converted to H_2) alongside the electricity network

Source: Frontier Economics

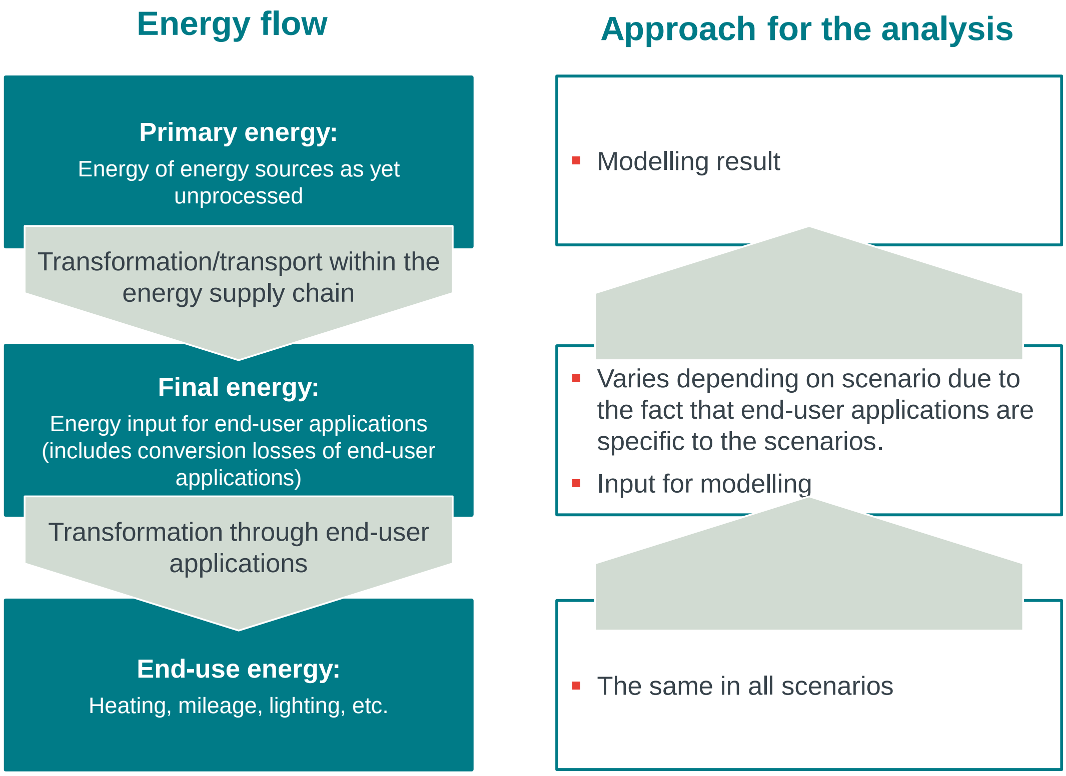
2.3 Different end-user applications in the scenarios lead to different final energy demand and energy mix

To derive the final energy demand for 2050 and determine the significance of different energy sources in each scenario, we used the bottom-up approach to analysis outlined in **Figure 7**, which has several stages:

- **Identical end-use requirements in all scenarios –** To ensure comparability of all scenarios, we assume identical end-use energy demand, meaning that the use (transport/heat/lighting, etc.) met by the energy delivered to consumers is equal for all scenarios. Expected demand-side efficiency gains (e.g. through insulation) are consistently taken into account in all scenarios (**Section 2.3.1**).
- **Scenario-specific final energy demand –** The scenarios differ, however, in terms of the end-user level technologies due to the varied availability of gas as an energy source. Since different levels of energy conversion efficiency are associated with different technologies used in end-user applications, we derive corresponding scenario-specific final energy requirements (**Section 2.3.2**).
- **Primary energy demand is the result of system modelling** – The final energy demand ultimately represents the supply requirement which the energy system (generation, storage and networks) must fulfil in each of the scenarios. In our analysis, the primary energy demand is modelled endogenously taking into account the various generation technologies and conversion losses along the supply chain and is thus a result of the analysis. Primary energy demand is therefore not defined as part of the scenarios (cf. **Section 4.2**).

Figure 7 illustrates this bottom-up approach to the analysis and the energy flows from primary energy to end-use energy.

Figure 7 Approach to determine the energy demand

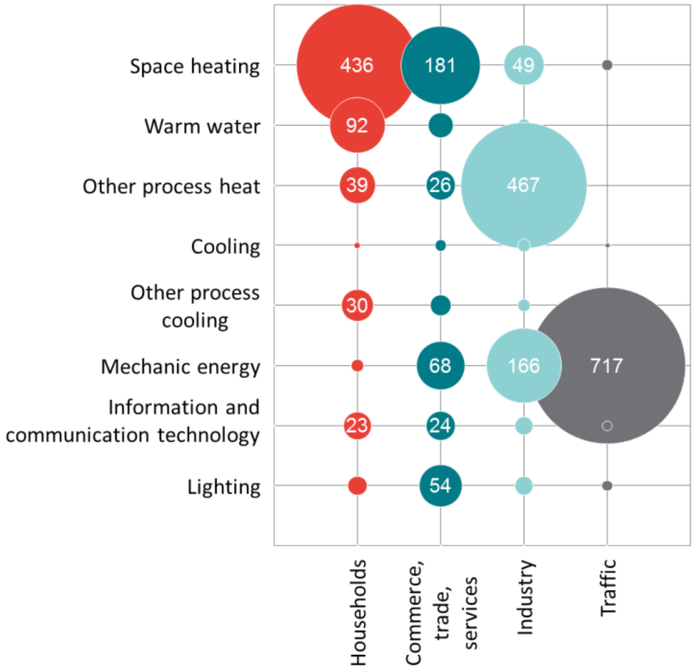


Source: Frontier Economics

2.3.1 Deriving the end-use energy demand in 2050 based on established studies

Our analysis starts by looking at the final energy consumption existing today and its division across different application areas and sectors. Most of the final energy demand is from space heating and hot water in households and in trade, commerce and services (TCS), process heat in the industrial sector, and mobility (**Figure 8**).

Figure 8 Final energy demand according to sector and application areas – 2015, in TWh/a



Source: Frontier Economics based on data from AG Energiebilanzen e.V.

Note: The area of the circles indicates the size of the respective energy demand.

Using this as our basis, the current end-use energy demand for areas with the largest final energy demand is determined and projected to the year 2050, based on third-party studies. Key assumptions made here include:

- **Space heating and hot water** – Based on Fraunhofer (2015), the end-use energy demand for space heating and hot water declines by 34 per cent in all scenarios from 2015 to 2050. This reduction is largely due to renovating existing buildings and replacing existing building stock with new buildings as well as by a minor decline in population.
- **Mobility** – Based on Federal Environment Agency (2016) data, increasing traffic volumes are assumed: passenger transport kilometres are assumed to increase by 25 per cent between 2015 and 2050 and the number of tonne-kilometres in freight transport is assumed to increase by 51 per cent (the total is calculated across all modes of transport).

2.3.2 Determining final future energy demand while taking scenario-specific application technologies into consideration

Based on the above assumptions about the required end-use energy, we derive the necessary final energy demand for each scenario (cf. ANNEX A for further details to derive energy demand in 2050). We make assumptions about which technologies will be ultimately used to convert the energy source into the required end-use energy for each of the scenarios, while also considering the associated conversion efficiency:

- **Space heating and hot water supply**
  - **Direct use of RES in all scenarios** – For all scenarios, we equally assume that a portion of the heat supply is provided by the direct use of renewable energy (solar thermal energy, biomass in direct form as well as ambient heat via heat pumps) and/or district heating.
  - **Green gas only in the "Electricity and green gas"** – In the "Electricity-only" and "Electricity and gas storage" scenarios, most of the heat is supplied by electric heat pumps and a small portion by direct power heating. In the "Electricity and green gas" scenario, a (smaller) portion is supplied by electrical heat pumps (particularly in new buildings), while the remaining portion (particularly in existing buildings) is supplied by gas-based technologies (above all, gas boilers).
  - In all scenarios, the final energy demand for space heating and hot water is reduced by about 35 per cent (**Figure 9**) compared to today. This is mainly driven by the reduced end-use energy demand for space heating and hot water (see **Section 2.3.1**).
- **Energy supply for transport**
  - **Power-to-liquid (PtL) for air travel and shipping** – All scenarios equally assume the future use of liquid fuels in air travel and shipping industries, since electrification seems infeasible based on current knowledge. We assume that the liquid fuels will be synthetically produced in a CO_2-neutral manner in future. Due to the comparative cost advantages of foreign locations as well as the generally global market for liquid fuels, our standard assumption is that these resources are entirely imported in all scenarios.
  - **Electricity for rail transport** – Although electricity is already the dominant energy source for rail transport, further electrification is foreseeable. We adopt the assumptions of the Federal Environment Agency (2016) for this transport segment and we assume that rail transport will be completely electrified by 2050 in all scenarios.
  - **50 per cent of road traffic powered by PtL** – We assume in all scenarios that 50 per cent of traffic in regional and long-distance transport in 2050 will be supplied with imported synthetically produced liquid fuels (as with aviation and shipping).
  - **The energy use for the remaining 50 per cent of road traffic varies depending on the scenario**. The remaining 50 per cent of the transport volume in road traffic in the "Electricity-only" and "Electricity and gas storage" scenarios is powered exclusively by electricity. In the "Electricity and green gas" scenario, gas-based vehicles powered by green gas are also used to some extent in addition to electric vehicles.

In terms of energy demand in transport, the main difference between the scenarios arises from differences in the share of electromobility in road traffic.

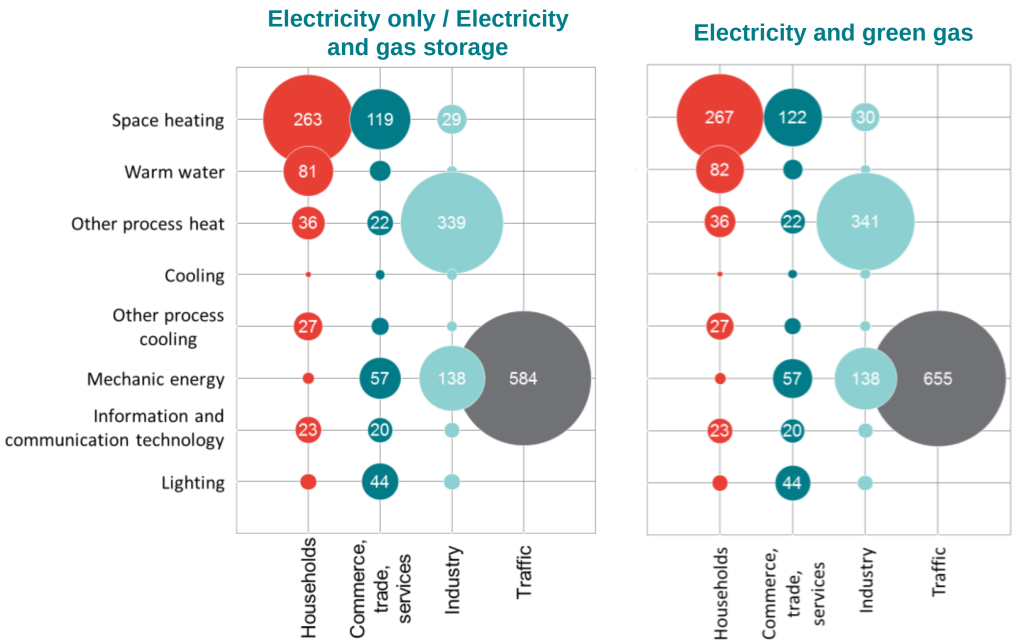
In total, the final energy demand in transport is reduced by approximately 20 per cent in the "Electricity-only" and "Electricity and gas storage" scenarios and by 10 per cent in the "Electricity and green gas" scenario (**Figure 9**).

Leveraging more efficient technologies allows the increase in transport volumes in all 2050 scenarios compared to 2015 to be met by a lower final energy demand.

- **Process heat –** Based on DLR data (2012), we assume that the final energy demand for industrial processes will decline by 26 per cent from 2015 to 2050 (**Figure 9**). While electricity-based processes are primarily used in the "Electricity-only" and "Electricity and gas storage" scenarios, green gas-based processes (particularly hydrogen) are increasingly used in the "Electricity and green gas" scenario.

We derive the final energy demand for each scenario using the procedure described above (**Figure 9** and **Figure 10**).[7] All further analysis then uses this level of demand as the form and quantity of energy to be supplied by the energy system. In accordance with the assumption that end-users are completely supplied using electricity-based sources, the final energy demand is the same in the "Electricity-only" and "Electricity and gas storage" scenarios. In contrast, however, green gas also plays a role in the heating and transport sectors in the "Electricity and green gas" scenario. Due to technology-related differences in the energy conversion at the end-user application stage, the final energy demand for the "Electricity and green gas" scenario is about 4 per cent higher compared to the other two scenarios.

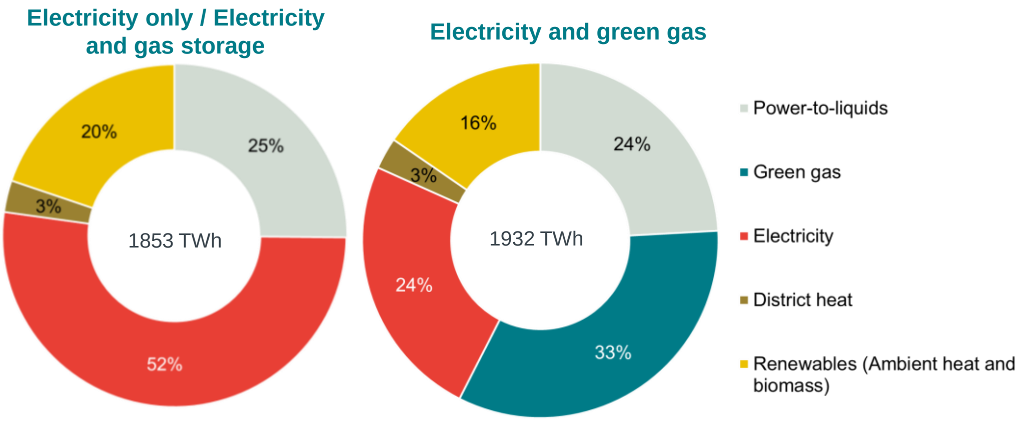
Figure 9 Final energy demand according to sector and application areas in each scenario – 2050, in TWh/a



Source: Frontier Economics

[7] The illustration refers exclusively to the final energy demand. Storage and conversion losses related to the delivery of energy from the source to the end consumer have not been taken into account here.

Figure 10 Breakdown of final energy demand by energy source in each scenario



Source: Frontier Economics

The demand for electricity and gas at the end-consumer level in Germany in 2050 is a key input (**Figure 11**) for our system modelling using the electricity market model and the electricity and gas network models. In the "Electricity and green gas" scenario, the scale of electricity and gas demanded by end-consumers in Germany in 2050 will be roughly comparable to today (for further details, see ANNEX B deriving the distribution of energy sources in the scenarios). The other two scenarios show large differences in end user demand compared to today.

Figure 11 Annual final demand for electricity and gas in each scenario (excluding electricity and gas used in energy conversion in PtG)[8] – Germany, 2050

Scenario	Demand for electricity	Demand for gas
Electricity-only	965 TWh	0 TWh
Electricity and gas storage	965 TWh	0 TWh
Electricity and green gas	468 TWh	645 TWh
Compared to Germany in 2015[9]	515 TWh	601 TWh

Source: Frontier Economics

Note: The electricity and gas demand values do not include conversion losses from power-to-gas plants or gas exports to supply neighbouring European countries.

The distribution of energy consumption over the course of the year

Total cumulated energy demand in a year is not the only decisive factor when it comes to the electricity system design, including all generating plants, energy storage facilities and networks. The distribution of demand over the year is also important. Accordingly, assumptions about how energy consumption is distributed throughout the year are made within each scenario (See ANNEX E.2

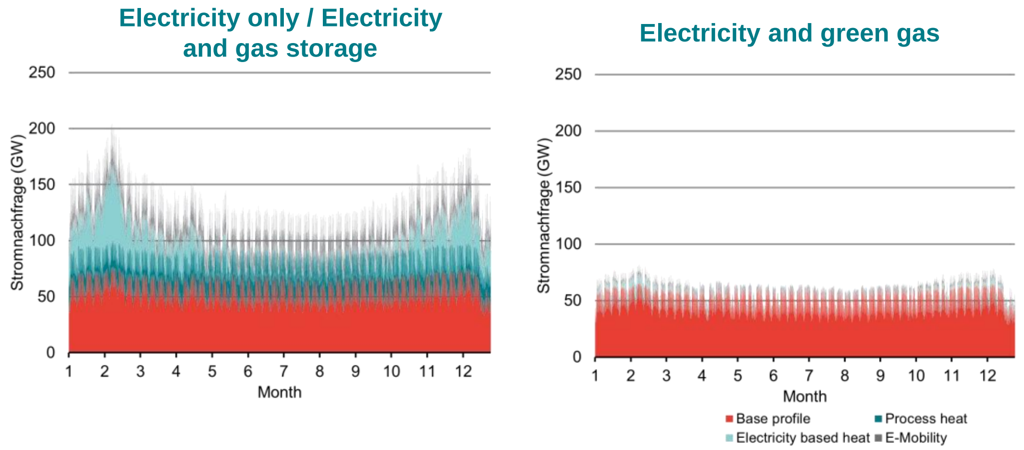
[8] The quantity of green gas required for conversion to electricity as well as for the production of synthetic gas is determined endogenously within the electricity market model, see **Section 4.2.4**.

[9] Cf. AG Energiebilanzen e.V. (2017).

for further details on deriving the electricity consumption profiles in the scenarios).

- **Electricity consumption** – Hourly electricity consumption profiles are created exogenously (**Figure 12**) which serve as input data for the electricity market model in which electricity consumption can be displaced over time using demand-side flexibility (e.g. heat pumps, electric vehicles) or electricity storage (e.g. pumped hydro storage, batteries).[10]
- **Gas consumption –** End-consumers consume gas only in the "Electricity and green gas" scenario (645 TWh per year, see **Figure 11**). We assume that the existing volume of gas storage will suffice to manage seasonal fluctuations of gas consumption in future.

Figure 12 2050 electricity load profile in each scenario as input to the electricity market model (excluding electricity demand for PtG)[11]



Source: Frontier Economics

2.4 Use of power-to-gas conversion technology varies across the scenarios

The scenarios differ particularly in terms of the technologies available for using green gas. The following assumptions are made with respect to the possibility of synthetically producing green gas:

- **"Electricity-only" scenario –** This scenario offers no potential for power-to-gas conversion, given the assumption that the gas infrastructure is not used at all (including storage).
- **"Electricity and gas storage" scenario** – This scenario includes the technological possibility to temporarily store renewably generated electricity in the form of gas via PtG and later to convert it back to electricity by burning it in gas fired power plants ("power-to-gas-to-power" or PtGtP). This storage can be used, in particular, to smooth out the seasonality of final electricity

[10] Other assumptions used to create the electricity consumption profiles can be found in Annex E.2.

[11] The electricity demand required to produce synthetic gas is determined endogenously within the electricity model, see **Section 4.2.4**.

consumption (caused by the heating sector) and supply electricity during dark periods with little wind, i.e. when the supply of renewable electricity is low.

- **"Electricity and green gas" scenario** – In this scenario, a significant portion of the final consumption will continue to be supplied by a gas energy source, which must, however, be provided as green gas by the year 2050. Accordingly, it is necessary to produce these quantities of green gas in PtG plants (at least 645 TWh, see above). To ensure complete comparability of the scenarios, we assume that all the green gas consumed in Germany will also be produced there. As a result, the import of green gas is not factored into the calculations. Therefore, Germany has the same degree of energy supply autonomy in all scenarios. In practice, however, the possibility of using the gas infrastructure to import green gas may be quite important (cf. **Section 4.4**). This implies that our approach can be considered conservative with respect to this scenario. PtGtP can also be used in this scenario.

Power-to-gas assumes 50 per cent each of hydrogen and synthetic methane

The following technological options are available for the use of power-to-gas:

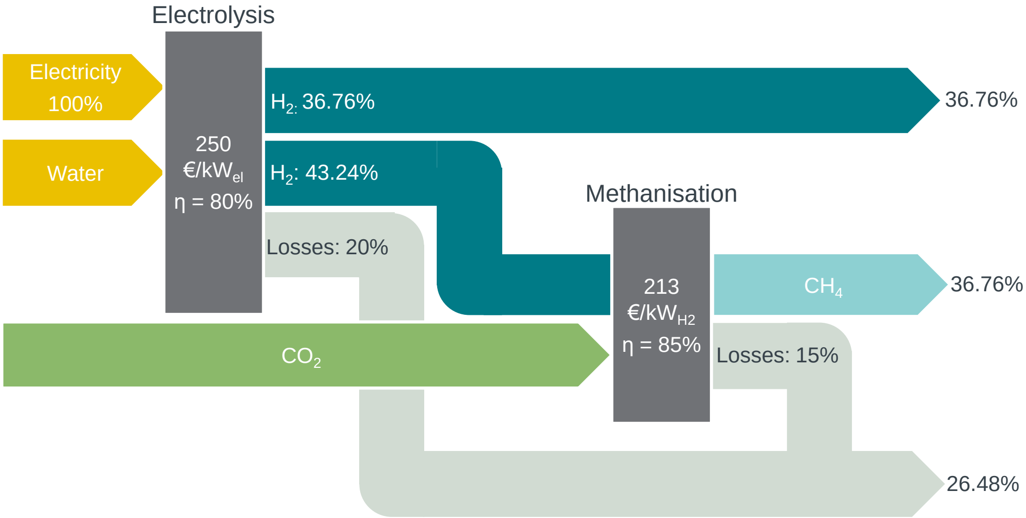
- Directly using hydrogen as a product of electrolysis; or
- Converting hydrogen into methane via methanisation and then using the methane (in which case, combustion eventually releases the CO_2 quantity that was previously bound during methanisation - thus, the use of green gas is CO_2-neutral).

Here, it can be assumed that in practice we will observe a mix of the two technologies, given the various advantages of synthetic methane (e.g. higher energy density; no adjustment of gas network and end-applications required) and hydrogen (e.g. no CAPEX and no CO_2 needed for methanisation; lower conversion losses), respectively. Given the rapid pace of technological advancements in this field, the general assumption we make is that 50 per cent of the green gas is directly transported and used as hydrogen (PtH2, in the transport and industry sectors), while the other 50 per cent of the green gas is methanised (PtCH4) and transported, particularly via transmission and distribution networks, to heat consumers.

Methanisation requires a carbon source. We assume that carbon can be obtained from biogas and biomass power generation as well as from unavoidable CO_2 emissions from industrial processes. In the case of reconversion, CO_2 can also be captured and then made available again for methanisation. Overall, we believe that an expensive process of direct air capturing of CO_2 will not be required due to the potential of all the domestic sources of CO_2 still remaining in 2050. The cost of supplying CO_2 is estimated at EUR 50 per tonne.[12]

[12] In the case of gas demand of 645 TWh, it is assumed that 50 per cent of the green gas will be provided in the form of methane. The carbon demand required for methanisation is equivalent to around 67 million tonnes of CO_2 per year. It is assumed that biogenic sources and the remaining emissions from industrial processes can be used to produce CO_2, which eliminates the need to capture CO_2 from the air. Hermann et. al (2014) reference that the costs of CO_2 production range between EUR 32.6/t of CO_2 and EUR 90/t of CO_2. For our analysis, we assume the cost of CO_2 is EUR 50/t of CO_2.

Figure 13 **Main assumptions made for the parameterisation of power-to-gas plants for an even split of CH4 and H2 (in 2050)**



Source: Frontier Economics

2.5 The form of energy transportation available depends on the scenario

In line with the assumptions made regarding the energy mix of the end-user applications, the scenarios also differ in terms of the possibilities for the transport of energy required along the supply chain:

- **"Electricity-only" scenario** – In this scenario, the connection between energy generation and final energy use is only made using electricity networks and electricity storage systems. The gas infrastructure is, therefore, no longer required in this scenario. This, however, does not apply to some gas transport lines which – despite full electrification in Germany – will still be required for transporting the European gas supply in 2050 due to Germany's central location (transit flows).[13] Gas transportation networks (including gas storage) and gas distribution networks that are not required must be decommissioned, secured and partially dismantled.
- **"Electricity and gas storage" scenario** – The potential for seasonal gas storage and reconversion (PtGtP) requires some gas transportation infrastructure. This scenario assumes either that PtG plants, gas storage systems and gas fired power plants are located close to large electricity production centres (particularly wind farms) or the presence of location-specific point-to-point gas pipeline connections between PtG plants, gas storage systems and gas fired power plants. Accordingly, it is assumed that the supra-regional transport of energy is carried out exclusively by electricity networks, eliminating the need to use transmission and distribution networks for gas to deliver energy to the end consumer and allowing them to be

[13] It is assumed that less ambitious climate goals will be pursued in the EU outside Germany (80 per cent reduction of CO_2 emissions by 2050 compared to 1990, instead of a 95 per cent reduction as is the case in Germany). In some neighbouring countries, it is thus assumed that natural gas will remain an important component of the energy supply in 2050.

decommissioned (with the exception of the gas transit pipelines and the gas connector pipelines between PtG plants, gas storage systems and gas fired power plants).

- **"Electricity and green gas" scenario** – End-consumers are supplied with green gas in this scenario. Accordingly, in parallel to the electricity network, the existing gas infrastructure used for transporting energy from energy sources to where it is finally consumed will continue to be used (and partially adapted for hydrogen).

3 AN "ELECTRICITY-ONLY" SCENARIO IS PROHIBITIVELY EXPENSIVE AND UNREALISTIC

SUMMARY

In selecting the scenarios, it should be noted that the extreme scenarios systematically exclude certain technological options and therefore limit the potential to optimise the energy system, which pushes up system costs.

This is reflected when considering the practicality of the "Electricity-only" scenario, as explained above. It is immediately clear that this scenario is impractical for a number of reasons:

- The seasonality of demand for heat means supplying the heating sector using electricity alone creates completely new challenges for planning the capacity of electricity networks (**Section 3.1**); and
- Due to the current lack of technological options for the long-term seasonal storage of electricity (apart from conversion to gas and the storage of the gas, i.e. power-to-gas storage), managing such seasonal demand would be prohibitively expensive and therefore uneconomical and probably infeasible – as many recent studies have shown (e.g. Enervis [2017] and Energy Brainpool [2017]) (**Section 3.2**).

  This is also one of the reasons why the German Federal Government also acknowledges the lack of any alternative to power-to-gas storage, at least in the case of long-term storage (**Section 3.3**).[14]

Since the "Electricity-only" scenario can be excluded as unviable for the future based on statements and studies presented in this section, we focus our quantitative analysis in **Section 4** on the impact in terms of system costs when the gas network is used to transport energy from generation to its final use – beyond the use of power-to-gas for seasonal storage (**Section 3.4**).

> “
>
> With an undisputed need for green gas for seasonal storage, the study therefore focuses on the added value of gas networks for transporting energy from where the energy is generated to its final use

[14] Cf. Federal Ministry of Economics and Energy (2017) – results paper Electricity 2030 – long-term trends – tasks for the next few years, p. 19.

3.1 Seasonal demand for heat is the main challenge imposed on the system

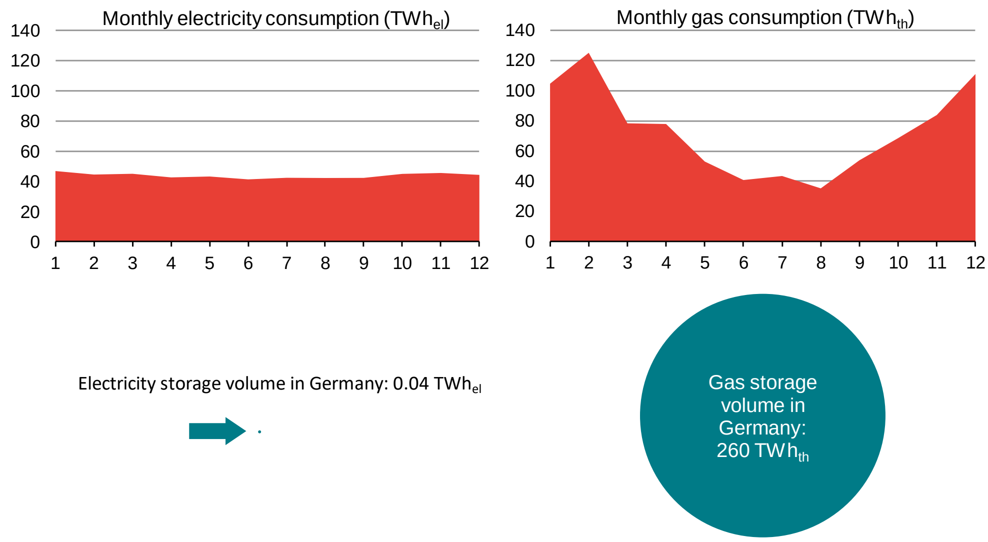
The heat sector's supply of energy has two fundamental characteristics:

- high seasonality of demand, with high demand during the winter months and low demand during the summer months; and
- a need to hold a large stock of gas, since the exact level of demand depends on specific temperature situations and the system must always be prepared to meet demand during extreme cases e.g. during a 1 in 20 cold winter.

The main challenge to decarbonising the heat and transport sector is therefore designing the system to handle such rare and extreme situations with corresponding consequences for economic efficiency. Investments must inevitably be made in the capacity to supply energy, some of which may only be fully utilised once every 20 years.

While such a 1 in 20 scenario is standard practice for planning in the gas supply sector[15], such a scenario would be quite a novelty for an infrastructure system operated purely on electricity in Germany. This is reflected in **Figure 14** below, which compares today's monthly demand profile in the gas and electricity sectors for different years. To illustrate how the different technical system designs are affected by the structure of demand, the figure also compares currently available storage capacities in the German gas and power systems.

Figure 14 Comparison of monthly demand in the electricity and gas sector and available storage capacities (Germany, 2012)



Source: Frontier Economics based on information from Entso-E, IEA and the German Bundestag (2017)

In the context of sector coupling, interdependencies between the heat and transport sectors and the electricity sector are set to intensify, meaning that extreme supply situations in the heating sector will have a greater impact on the electricity sector in future. At the same time, the increase in weather dependent

[15] Cf. Ordinance (EU) No. 994/2010 Art. 8 Para. 1 – SoS-VO.

electricity generation from wind and sun creates additional uncertainty, which may jeopardise the electricity supply and thus also the heat supply (as noted above, the supply of energy during dark periods with little wind). Such relationships can already be observed in today's energy system. For example, electricity demand in France has a high level of seasonality due to the high proportion of electric heating. This has exacerbated already strained electricity supply situations, which has prompted further policy measures to be adopted aimed at helping to manage the availability of electricity (specifically, a capacity market has been introduced in the electricity sector in France).

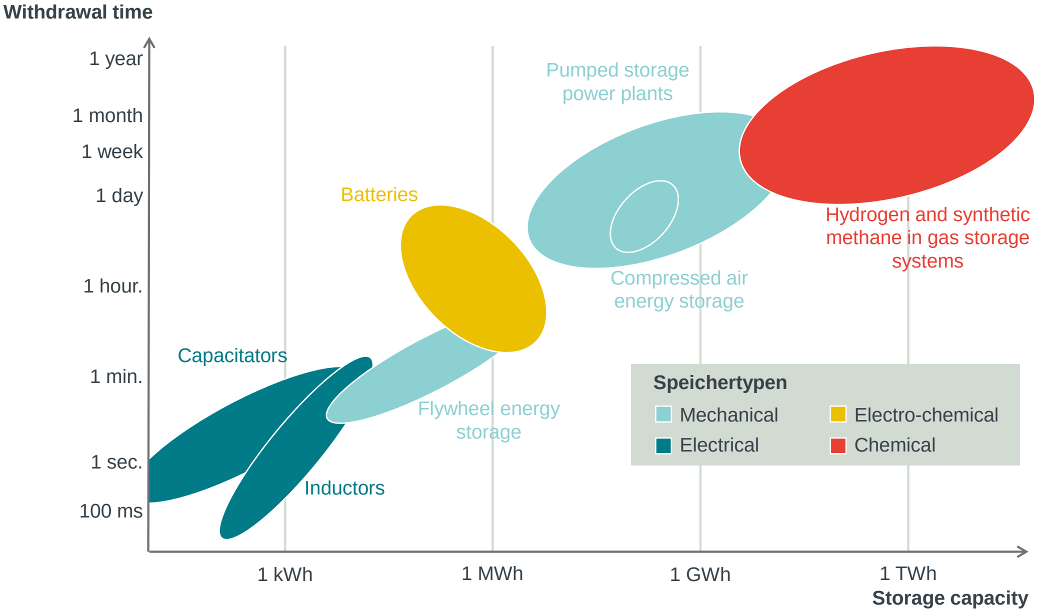
3.2 "Electricity-only" is prohibitively expensive for lack of seasonal storage

Since today's knowledge of an almost completely decarbonised electricity sector does not provide for any implementable technology for seasonal storage of electricity, an energy system operating entirely without any chemical storage (in gaseous form) and (at least in Germany) without any nuclear power and CCS would require the development of large surplus capacities of renewable energy and electricity networks. A scenario such as this would lead to excessive system costs, as simple analysis shows.

A rough calculation shows that an electricity storage system with a storage volume of around 35 TWh would be required for near-complete decarbonisation by direct electrification.[16] In comparison, the storage volume of pumped hydro storage power plants in Germany is currently around 0.04 TWh (this is equivalent to almost the entire current electricity storage volume in Germany, see **Figure 14**). Using pumped hydro storage power plants, the best currently available technology for storing electricity over the long term that does not require power-to-gas, as illustrated in **Figure 15**, would therefore require more than 800 times the current pumped hydro storage volume to manage differences between supply and demand. However, the natural potential in Germany and surrounding countries remains far off this requirement.

[16] This assumes complete decarbonisation and electrification of large portions of the final energy demand. Electricity is supplied by equal capacities of on-shore wind, off-shore wind and solar power so that total annual production meets total demand. The seasonal electricity storage requirements are determined using hourly differences between electricity demand and electricity generation.

Figure 15 Comparison of storage technologies



Source: Frontier Economics based on Sterner et. al (2014) p. 19 and in-house analysis

To provide adequate storage capacity using current battery storage technology, around 18 million containers covering an area as large as the state of Berlin and the city of Munich combined would be required.[17] As well as being technically infeasible, it would be extremely uneconomical to provide such storage capacity without using power-to-gas technologies.

This finding is reflected in the results of various studies that have also recently analysed scenarios similar to these:

- Enervis (2017) compares a scenario without any gas storage ("Green full electrification") with a power-to-gas scenario ("Green gas"). When electrifying the heating sector without using any power-to-gas technology, the study calculates that the additional costs will amount to EUR 145 billion by 2050 (not discounted) for the heating sector alone, excluding any network costs.
  - Unlike our study, this analysis is limited solely to the electrification of the heating sector. Traffic and industrial processes are not included and would further exacerbate cost disadvantages.
  - Furthermore, the (substantial) additional costs arising from expanding the electricity network in the case of no gas storage are not considered. The additional costs for the electrification scenario would be even greater if these costs were included.
- Energy Brainpool (2017) identifies the most affordable options for supplying energy during periods of extreme weather conditions, i.e. during cold, dark periods with little wind. These occur about once every two years according to the authors and lead to about 14 days of little green electricity being available,

[17] The example calculation is based on information from the STEAG large battery system, which comprises ten battery containers and an eleventh container with the control unit. Each container has a capacity of between 1.5 and 2 MWh and is 12.2 metres long, 2.4 metres wide and 2.6 metres high. A safety zone around the container of 2.4 metres must also be kept. Cf. STEAG, taken from https://www.steag.com/de/leistungen/grossbatterien/.

which requires a focus on the availability of electricity during such rare and extreme events. The authors conclude that these weather conditions can only be inexpensively managed through temporary storage via power-to-gas.

3.3 German Government recognises the need for PtG for seasonal storage

Last but not least, the current position of the Federal Ministry of Economics and Energy (BMWi) also reflects these results. In the results paper Electricity 2030,[18] the Federal Ministry of Economics and Energy highlights the significance of power-to-gas as a long-term storage system which would be sensible and necessary under circumstances with a high percentage of renewable energy in the energy mix:

> "*Conventional storage solutions are only able to store electricity for few hours and are not suited for a prolonged period without wind and sun. New technologies, such as power-to-gas, could serve as long-term-storage solutions, but are still extremely expensive due to conversion losses. Their use is sensible only with much higher shares of renewables in the electricity mix.*" (Federal Ministry of Economics and Energy (2017), p. 17).

3.4 Summary: a detailed examination of this scenario is not needed to draw inferences about the need for gas networks

The information provided above underlines the need for power-to-gas in the long term, at least as an energy storage system. The purpose of this study is therefore not to demonstrate the fundamental need – now almost universally acknowledged – to store gas on a seasonal basis as a reservoir of energy in comparison to the "Electricity-only" scenario. Instead, the purpose is to analyse the potential contribution that transporting energy from where it is generated to its final use through gas networks can make, in addition to simply using gas to serve as a form of temporary storage.

Consequently, the detailed analysis described in this report looks beyond the benchmark of an "Electricity-only" scenario. In doing so, the quantitative analysis forthcoming in **Section 4** examines the possible advantages of a gas infrastructure that includes transportation and distribution networks, even compared to a scenario where gas is only used as temporary storage.

[18] The Federal Ministry of Economics and Energy (2017) – results paper Electricity 2030 – long-term trends – tasks for the next few years.

4 RESULTS: INCORPORATING THE GAS INFRASTRUCTURE WOULD REDUCE DECARBONISATION COSTS AND BOOST ACCEPTANCE AND SECURITY OF SUPPLY FOR THE ENERGY TRANSITION

SUMMARY

Methodology

For the two scenarios "Electricity and gas storage" and "Electricity and green gas", we have carried out extensive analysis on associated system costs, taking account of the total costs that are

- arising for end-consumers in providing the corresponding end-user devices;
- incurred at the level of electricity transportation and distribution, including the necessary network expansion;
- incurred for gas networks and storage (investment and operation and, if necessary, dismantling); and
- incurred in the entire area of electricity production and possibly conversion in power-to-gas plants and reconversion to electricity.

Due to the findings described in **Section 3**, we consider the "Electricity-only" scenario not relevant as an option for practical implementation. The following, therefore, focuses on the advantages of retaining and using a gas infrastructure to deliver energy from where it is generated to the end user, including the direct use of green gas by end-consumers ("Electricity and green gas" scenario), compared to a scenario where green gas were only used for temporary storage for later reconversion to electricity ("Electricity and gas storage" scenario).

Results

In conclusion, there are significant advantages of end consumers directly using green gas, which will be explained in detail in the following sections:

- Using the gas infrastructure for green gas will not compromise the climate protection goals in any way but will instead help achieve (near) complete decarbonisation (**Section 4.1**).
- Retaining gas networks and using green gas directly can help achieve considerable cost savings in the energy system, meaning that this scenario can help to achieve climate protection goals far more cost-effectively than through comprehensive direct electrification. Our results show that by 2050, annual system cost savings will be around EUR 12

million (in real terms expressed as 2015 values) for the "Electricity and green gas" scenario compared to the "Electricity and gas storage" scenario, where no gas networks are used to supply end consumers. These savings reflect, among other things, the ability to eliminate the need for investments in electricity networks and end-user applications amounting to around EUR 268 billion by 2050 (**Section 4.2**).

- In addition, the use of the gas infrastructure brings a wealth of other benefits that cannot easily be quantified in monetary terms. It can also be expected that using the existing infrastructure will significantly boost public acceptance (**Section 4.3**) of the energy transition. Retaining the gas infrastructure and its extensive storage options will also significantly boost security of energy supply (**Section 4.4**).

4.1 Gas infrastructure helps to achieve climate protection goals

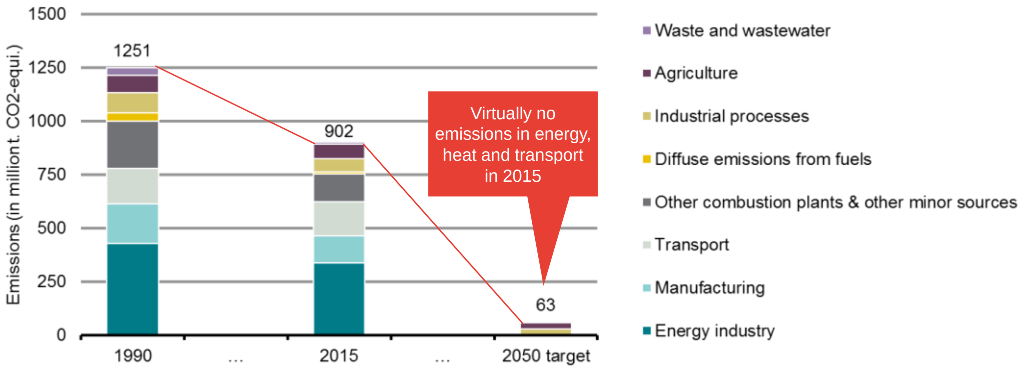
The results of the analysis show that the use of gas networks does not compromise climate protection goals in any manner. Synthetically produced "green methane" can be fed directly into the networks, while generated "green hydrogen" requires only minor adjustments to the gas infrastructure up until 2050.

It is important to understand here that while the final use of green methane produces CO_2 emissions, this amount of CO_2 has already been completely removed from the environment while producing the synthetic gas. This results in an overall climate-neutral use of synthetic gas, similar to the use of biomass.

The climate protection goals to reduce greenhouse gases by 95 per cent by 2050 as compared to 1990 – or even by 99 per cent in the case of the energy, transport and heat sectors – are accordingly fully met by all scenarios alike, as demonstrated by **Figure 16**.

> "Whether consumers are supplied with renewable energy as electricity or green gas is irrelevant when it comes to the impact on the climate!

Figure 16 Greenhouse gas emissions in Germany in all scenarios



Source: Frontier Economics (historical values based on information from the Federal Environmental Agency: National greenhouse gas inventory 2017, final status 04/2017).

Ultimately, when it comes to achieving climate protection goals, it is only the form in which primary energy is supplied that matters – this is almost exclusively in the form of renewable energies in all of the scenarios considered. The form of transportation (i.e. whether the consumer is supplied with energy in the form of electricity or with gas in the form of green gas) is irrelevant in climate impact terms.

4.2 The use of gas networks reduces total energy system costs due to reduced electricity network costs and cheaper end-user applications

Overall, our analysis shows that the continued use of the gas networks to deliver energy from where it is generated to the end user ("Electricity and green gas" scenario) offers further cost savings compared to a world in which the gas networks are not used ("Electricity and option of gas storage" scenario). By 2050, the overall net savings will amount to around EUR 12 billion per year (in real terms expressed as 2015 values). These savings reflect, among other things, the ability to eliminate the need for investments in electricity networks and end-user applications amounting to around EUR 268 billion by 2050 (undiscounted).

Figure 2 illustrates that the total cost savings of using the gas network comprise:

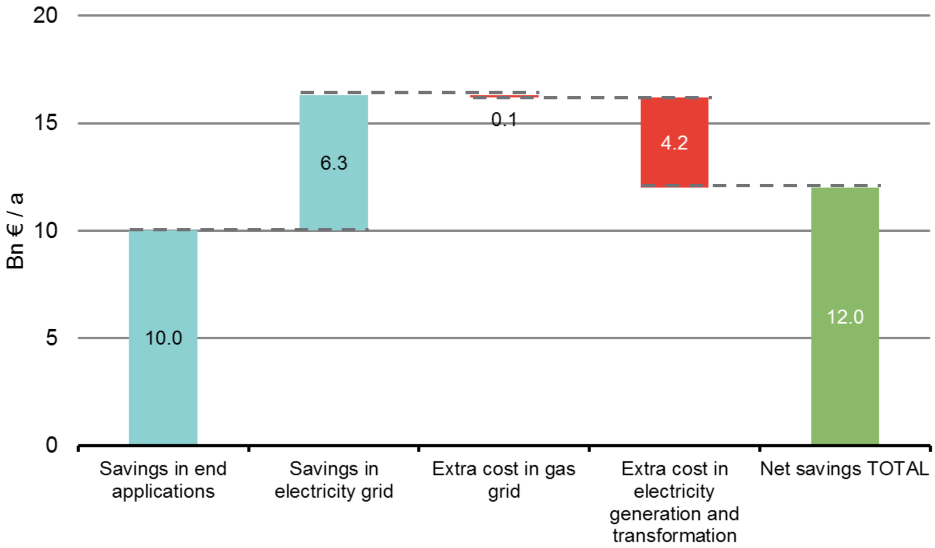
- lower costs for gas-based end-user applications (EUR 10 billion per year by 2050), especially in the heating sector (**Section 4.2.1**); and
- savings from significantly lower electricity network expansion requirements (EUR 6.3 billion per year by 2050; (**Section 4.2.2**)

These savings of EUR 16.3 billion significantly outweigh the additional costs caused elsewhere through the use of gas to deliver energy from where it is generated to the end user, specifically:

- for retaining and partially converting the gas networks (additional costs of EUR 0.1 billion per year by 2050 as compared to the decommissioning costs; **Section 4.2.3**); plus

- the costs for additional electricity generation and power-to-gas plants required due to conversion losses (EUR 4.2 billion per year by 2050); **Section 4.2.4**).

Figure 17 Annual system net cost savings in the "Electricity and green gas" scenario compared to the "Electricity and gas storage" scenario (by 2050)

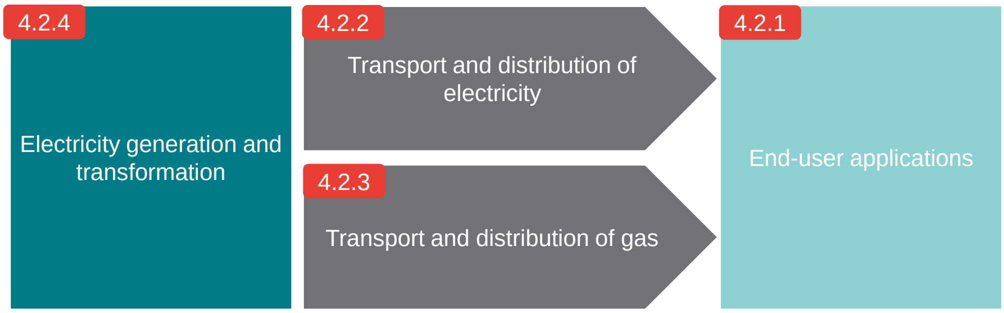


Source: Frontier Economics

Note: The per annum costs are shown in EUR2015 for the year 2050.

The methodology and results of the system cost analysis are explained in the following. The analysis is conducted along the entire end-consumer energy supply chain, as illustrated by **Figure 18**.

Figure 18 Process for determining the system costs along the entire energy supply chain



Source: Frontier Economics

4.2.1 End-user applications: extensive changes can be avoided and costs saved through using gas

This section presents:

- the approach we use to determine the costs for end-user applications; and
- a summary of the main results.

Further details about the analysis can be found in ANNEX A.

Approach for determining costs for end-user applications

End-user applications that transform an energy source into the end-use energy form required play a vital role in system costs. Since the analysis aims to determine cost *differences* between the various scenarios, we pay particular attention to end-users for whom significant differences are considered likely to arise between the scenarios considered. The analysis therefore focuses on the fields of end-user applications with the largest final energy demand (cf. **Figure 8** on page 16):

- Space heating and hot water;
- Supply of process heat; and
- Mobility supply.

While the supply costs of end-consumer fuels (electricity or PtG) are determined within the electricity market model as part of electricity generation and conversion costs (see **Section 4.2.4**), this part of the analysis is used to determine the different costs of purchasing and servicing end-user applications.

The assumptions made on the costs of purchasing individual end-user applications are taken from various established studies.[19] To facilitate comparison with the other cost items (e.g. electricity or gas networks) with different amortisation periods, the costs of end-user applications are annuitised based on the specific lifetimes of the applications.

Results for the costs of end-user applications

In terms of end-user applications, there is an overall annual cost saving of EUR 10.0 billion (in real terms expressed as 2015 values) if some of the end-user applications in the heat and transport sector in 2050 are based partly on gas rather than electricity-only technologies. In total, investments amounting to EUR 155 billion by 2050 can be avoided.

These savings comprise mainly effects arising in the heat sector, and to a lesser extent, in the transport sector.

- Our analysis reveals cost savings of EUR 8.4 billion per year in the heat sector. In comparison to a scenario of only using electricity, this corresponds to avoided investments in the heat sector of EUR 130 billion by 2050.

  The main factor here is avoiding the need to replace gas boilers by capital-intensive heat pumps. In terms of energy efficiency, the advantage of heat pumps is reflected in the lower energy demand in electricity generation and conversion. This has no effect on the investment costs in the applications considered here, but is factored into cost-savings elsewhere in the energy system modelling (cf. **Section 2.3 and 4.2.4**).

  Although the "Electricity and green gas" scenario also uses heat pumps, particularly in new buildings, these are more prevalent in the building inventory in the "Electricity and gas storage" scenario (since gas-based end-

[19] For the heat sector Fraunhofer (2015a) and for the transport sector Fraunhofer (2015b) as well as UBA (2016).

user applications are not used in this scenario), making the "Electricity and green gas" scenario more favourable in terms of application costs.

- Our analysis shows cost savings of EUR 1.6 billion per year in the transport sector. In comparison to a scenario of only using electricity, this corresponds to avoided investments in the transport sector of EUR 25 billion by 2050.

  This is due to the lower unit costs of gas-based vehicles compared to electric vehicles. The efficiency benefits of electric motors are reflected in the lower demand for energy and included in the analysis for the generation and conversion of electricity (cf. **Section 2.3 and 4.2.4**).

4.2.2 Transport of electricity: existing gas pipelines as an alternative to expanding the electricity network

This section presents:

- our approach to determining the required expansion of the electricity network in the different scenarios;
- a summary of our results; and
- a detailed discussion of the findings for the transmission and distribution networks.

Further details about the analysis can be found in ANNEX B.

Approach to determining the required expansion of the electricity network

We consider the impact of sector coupling on the need to expand the transmission network and the distribution networks in Germany.

For the **transmission network**, we create a model for the year 2035 for electricity based on the current network development plan (NDP) made by the transmission system operators (TSOs).[20] This means that the electricity network, including any expansions defined in the NDP up until 2035, will be the starting point for further planning. We use a market simulation to determine the generation of electricity from power plants, including from renewable energy facilities, and the electricity demand at each network node (i.e. taking into account the location of generation and demand).

We subsequently identify network bottlenecks for both considered scenarios in the year 2050 using a simulation of network operation on an hourly time frame. The simulation takes the use of PtG plants into consideration.

From the model results we determine the network upgrading and expansion measures required to completely eliminate the network bottlenecks for the scenarios considered in 2050. For all new lines constructed after 2035, we assume the use of underground cables . Only network upgrading measures on existing electrical circuits will be carried out as overhead lines:

[20] The expansion measures described in the Ten-Year Network Development Plan (TYNDP) 2016 are assumed in the case of neighbouring countries.

- **Network upgrading** of existing electrical circuits from 220 to 380 kV – If 220 kV electrical circuits overload, they will be replaced by 380 kV high-temperature conductors.
- **New construction** of 380 kV cables on existing lines – When individual 380 kV electrical circuits overload, it is assumed that a parallel 380 kV cable section will be installed on the same line.
- **Use of HVDC connections** – In addition to using AC lines, the expansion of high-voltage DC connections with DC technologies is assumed.

Repeated simulations of network operation and expansion ensure that the network expansion measures identified provide a transmission network model that has been developed to accommodate all situations relevant to the network design. To determine the costs of expanding the network, we use unit costs corresponding to those stipulated by the TSOs in the current NDP.

For the **distribution network**, the model approach is based on the Federal Ministry of Economics and Energy's distribution network study and on standardised networks.[21] The assumptions made in the scenarios with regards to developing installed RES capacity and consumer loads are transferred into standardised network use cases for each distribution network level. To take account of the heterogeneity of the German distribution networks relating to the existing network infrastructure and the different supply tasks, we apply a Monte Carlo simulation to determine network expansion for standardised distribution networks. The network expansion is carried out at the same time as electrical equipment in the model. The unit costs of distribution network investments correspond to those used in the Federal Ministry of Economics and Energy's distribution network study.

Overview of the electricity transport results

In comparison to the "Electricity and gas storage" scenario, the transport of energy using gas networks in the "Electricity and green gas" scenario leads to a significant reduction in the required electricity network expansion, at both the distribution and transmission network levels.

Both scenarios assume that the planned expansion of the network stipulated in the current network development plan will be completed by 2035. Both scenarios then require further expansion of the electricity network up until 2050. Using existing gas networks in the "Electricity and green gas" scenario significantly reduces the need to expand the electricity network as compared to the "Electricity and gas storage" scenario (**Figure 20**):

- By using the gas infrastructure, approximately 17,800 kilometres of electrical circuits requiring expansion or upgrading can be avoided in the transmission network.
- Using the gas infrastructure means approximately 476,000 kilometres of medium and low voltage electrical circuits and approximately 33,800

[21] Cf. E-Bridge, IAEW, OFFIS (2014).

kilometres of high voltage electrical circuits requiring expansion or upgrading can be avoided in the distribution networks.

The avoided upgrading or expansion of the network in the "Electricity and green gas" scenario means investments amounting to EUR 113 billion can be avoided by 2050 (without discounting future costs). Of this, avoided costs in the transmission network accounts for EUR 38 billion whereas avoided costs in the distribution network accounts for approximately EUR 75 billion.

Across all network levels, the "Electricity and green gas" scenario has a cost advantage of EUR 6.27 billion per year compared with the "Electricity and gas storage" scenario. This comprises a saving of EUR 1.87 billion per year in the transmission network and EUR 4.4 billion per year in the distribution network.[22]

Figure 19 Main results of the analysis of the electricity network

		Circuit length in 2015 (approx. values, km)	Electrical circuit length (km)		Requirement for network expansion in the "Electricity and gas storage" scenario in comparison to the "Electricity and green gas" scenario (km)
			"Electricity and gas storage"	"Electricity and green gas"	
Trans-mission network	EHV	35,000	79,980	62,190	17,790
Distribution network	HV	95,000	154,900	121,100	33,800
	MV & LV	1.6 million	2.40 million	1.92 million	476,000

Source: Research and simulation results, IAEW

Figure 20 Main results of the analysis of the electricity network (network expansion costs in EUR billion per year)

		Network expansion costs (EUR, 2015)		Additional costs "Electricity and gas storage" scenario in comparison to the "Electricity and green gas" scenario
		"Electricity and gas storage"	"Electricity and green gas"	
Transmission network	EHV	4.97	3.10	1.87
Distribution network	HV	3.48	1.52	4.40
	MV & LV	4.34	1.89	

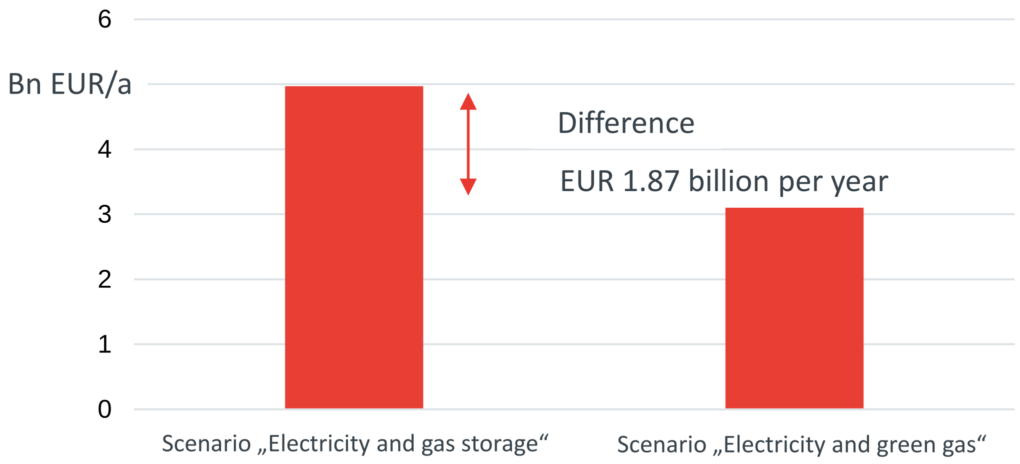
Source: Research and simulation results, IAEW

[22] The annuity values were calculated based on the lifetimes of the respective operating resources as provided in the Annex.

Results for the transmission networks

In the case of the **transmission network**, the network expansion avoided between 2015 and 2050 results in an annuitised cost saving of EUR 1.87 billion per year in the "Electricity and green gas" scenario (**Figure 21**).[23]

Figure 21 Annuitised network expansion costs in the transmission network (Network expansion from 2015 to 2050)



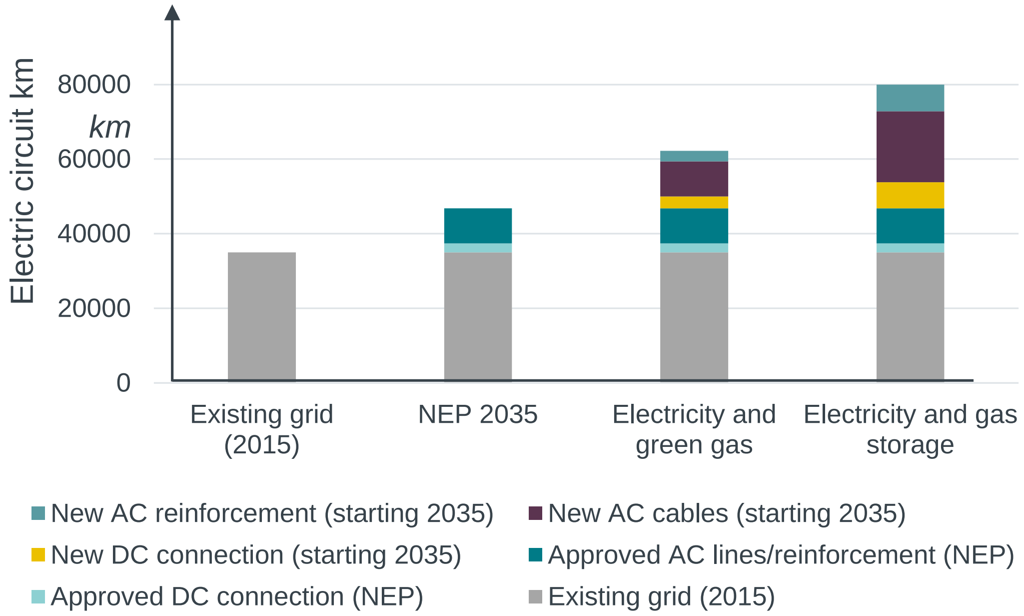
Source: Simulation results IAEW

17,800 circuit kilometres of transmission expansion in AC and DC networks can be avoided compared to the "Electricity and gas storage" scenario. **Figure 22** shows the electrical circuit lengths of the current transmission network and those of the extended networks.[24]

[23] A detailed breakdown of the annuity costs and the assumed lifetimes of the network operating resources can be found in ANNEX B.

[24] NDP 2035 refers to scenario B for 2035 in the network development plan of the German transmission system.

Figure 22 Electrical circuit lengths for each technology



Source: Simulation results IAEW

In both scenarios and in the "Electricity-only" scenario, the electricity network needs to be expanded in Southern Germany due to the high amount of installed PV capacity and the resulting supply peaks.

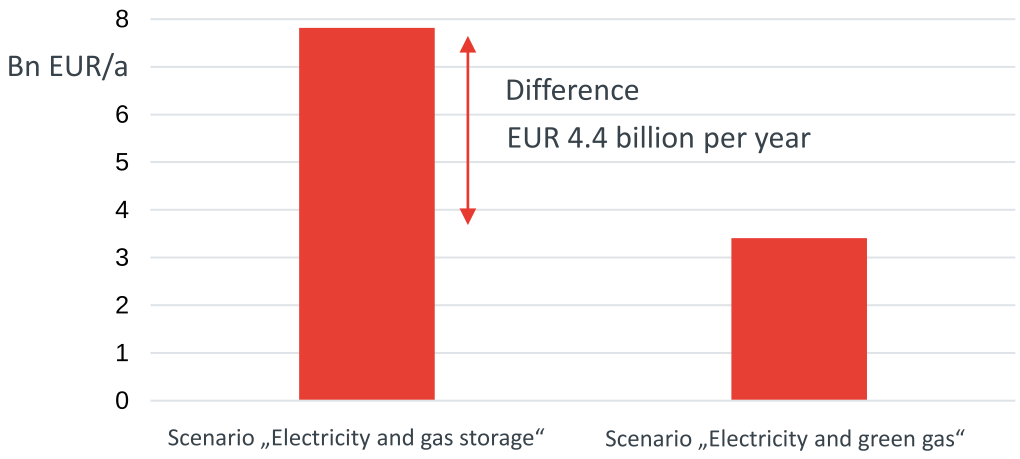
The lower electricity network expansion in the "Electricity and green gas" scenario is the result of higher PtG capacities, which have two effects on the need for electricity network expansion:

- The increased use of PtG plants absorbs surplus electricity especially during hours of high wind energy and PV feed-in, and thereby relieves the network of high flows due to the proximity of the PtG plants to the electricity generation.
- The PtG capacities not used by the market are then made available for network-compatible use.

Distribution network level results

In the case of the **distribution network**, we find an annuitised cost advantage of approximately EUR 4.4 billion per year in the "Electricity and gas green" scenario as compared to the "Electricity and gas storage" scenario (**Figure 23**).

Figure 23 **Annuity network expansion costs in the distribution network (Network expansion from 2015 to 2050)**



Source: Simulation results IAEW

476,000 kilometres of expansion of low and medium voltage electrical circuits in distribution networks and approximately 33,800 kilometres of high voltage electrical circuits can be avoided compared to the "Electricity and gas storage" scenario.

The avoided distribution network expansion is mainly due to two effects:

- On the one hand, the maximum electricity load of 191 GW (mainly due to the direct electrification of the heat sector), which occurs in the "Electricity and Gas Storage" scenario, clearly exceeds the value of 82 GW in the "Electricity and green gas" scenario, which reflects the current scale of today's peak loads. This creates a load-driven network expansion requirement for the electricity network in the "Electricity and gas storage" scenario.
- Conversely, the network-compatible use of PtG plants in both scenarios helps to manage the peaks in generation from power stations and thus reduce the RES-driven electricity network expansion. Due to the higher installed PtG capacities, this effect is greater in the "Electricity and green gas" scenario.

4.2.3 Gas networks: the costs of retaining the gas networks in the "Electricity and green gas" scenario only slightly exceed those of dismantling them in the case where the network is not used.

This section presents:

- our approach for determining the cost effects of the gas network in both scenarios;
- an overview of our results; and
- a detailed discussion of the separate findings for the "Electricity and gas storage" and "Electricity and green gas" scenarios.

Further details can be found in ANNEX D.

Approach for determining costs for the gas infrastructure

In this part of the analysis, the effects of both the "Electricity and gas storage" and "Electricity and green gas" scenarios on the costs of gas infrastructure are determined. The following is considered here:

- **Investment costs** in new construction and expansion of the transmission and distribution networks for gas. For this purpose, we determine the need to retain some gas infrastructure for both scenarios separately.
- **Costs of retaining, restoring and partially restructuring the gas networks for hydrogen use**. Almost all the gas networks are retained in the "Electricity and green gas" scenario. Some, however, require minor adjustments due to the lower energy content and different combustion behaviour of hydrogen compared to natural gas (or synthetic methane). This applies primarily to systems such as compressors, power plants and metering technology.
- **Costs of the partial dismantling of the gas networks** after they are no longer used to transport and distribute gas in the "Electricity and gas storage" scenario.

Finally, the results of our assessment for the selected scenarios are compared to one another.

We use costs estimates from 2015 for investments and operations by the gas network operators (**Figure 24**) for our analysis, and extrapolate these costs to 2050 depending on the different role that gas networks play in both scenarios (see below for details).

Figure 24 Expenses for network operator in 2015 (in EUR million)

	Transmission network	Distribution network	Total
Investments in new construction and network expansion	341	682	1,023
Investments in retaining and restoring networks	155	431	586
Costs of maintenance and servicing	366	1,203	1,569
Total	**862**	**2,316**	**3,178**

Source: Monitoring report of the Federal Network Agency 2016 p. 276 ff

Overview of the results

The additional costs of retaining and converting the gas networks ("Electricity and green gas" scenario) in comparison to only operating electricity distribution networks and operating the remaining gas transit networks, are largely offset by the additional costs arising from dismantling ("Electricity and gas storage" scenario) gas networks that are no longer used.

By continuing to operate the gas networks, a total of EUR 111 million in additional net annual costs is incurred in the 'Electricity and green gas' scenario compared to the 'Electricity and gas storage' scenario (**Figure 25**). As shown in

Section 4.2.2, these are more than offset by the cost savings of EUR 3.9 billion by avoiding the need to expand the electricity network ("Electricity and green gas" scenario compared to the "Electricity and gas storage" scenario). The comparison of the minor additional costs of retaining gas networks and the significant costs saved by not expanding the electricity network reflects the infrastructure cost advantage of using the gas networks.

Figure 25 Comparison of the gas network costs (for 2050)

(in EUR million per year)	"Electricity and gas storage" scenario	"Electricity and green gas" scenario	Difference in costs
Investments in the expansion and restoration of networks	163	1,182	-1,018
Costs of maintenance and servicing	303	1,568	-1,265
Costs of dismantling and securing	2,173	0	2,173
Total	**2,639**	**2,750**	**-111**

Source: FourManagement

The results of the gas network costs are explained in further detail in the following.

The above results are derived based on the investment costs and the costs incurred by the German gas network operators having to maintain and service the gas transmission and distribution network, which measures almost 500,000 kilometres in length, as well as for possibly not having to dismantle the gas infrastructure (based on cost estimates from 2015). The derivation is described in detail in Annex D.

Effects on the gas network in the "Electricity and green gas" scenario

In the "Electricity and gas storage" scenario, we assume that almost all of the energy supplied by the gas industry up until now will be replaced by electricity.[25]

Since the German gas transmission infrastructure is the backbone of the European gas supply and will continue to connect consumers in Western, Southern and Eastern Europe to non-European sources of production, even in 2050, a residual infrastructure of gas transportation networks (i.e. transit pipelines) will be retained in this scenario. Significant parts of Germany's gas transmission system[26] (approximately 11,000 kilometres) form an integral part of the European transport network structure and their continued use is assumed in both scenarios.

[25] In processes where the use of hydrocarbons cannot be replaced for recycling and producing materials, it is assumed that these input materials can be reproduced locally. The infrastructure required for this purpose must then be set up and run by the operators of the industrial plants. The associated costs are therefore not included in the cost analysis.

[26] Based on the gas network map Transparency of ENTSOG, https://transparency.entsog.eu/.

Apart from the transit pipelines and the lines running between gas storage systems and/or power-to-gas plants, a large portion of the gas network is no longer required to be used in the "Electricity and gas storage" scenario. Due to rights of way agreements concluded between the gas network operators and property owners, these pipelines must – at the property owners' request – either be dismantled or, in the case of permanent decommissioning, secured in such a way so as to ensure that the pipelines and plants concerned pose no permanent risk to the general public. As a result, dismantling costs arise for the gas networks (see. Annex D.1):

- A total one-off expense of EUR 3.1 billion in dismantling costs can be assumed for dismantling or securing of pipelines in the transmission network (approximately 22,500 kilometres).[27]
- Depending on contractual arrangements and at the request of the cities and municipalities, distribution network operators, whose rights of way for pipelines are usually covered by concession contracts concluded with the municipalities, will incur between EUR 20 and 150 billion[28] in dismantling costs as a result of having to secure the 480,000 kilometres of distribution network pipelines that will no longer be used. A conservative approach has been adopted for our calculations which are based on the cost range's lower limit (i.e. one-time cost of EUR 20 billion). Since networks can only be decommissioned after all customers connected to these networks have undertaken conversion to other energy uses, it is assumed that network operators will incur considerable expenses for securing and dismantling pipelines only from 2035 onwards.

Based on the conservative estimate of total costs, total annuitised costs amount to around EUR 2.17 billion per year for securely decommissioning gas systems and dismantling infrastructure between 2035 to 2050. We use this cost as the basis for our further calculations.

To determine the investment costs, we assume in the "Electricity and gas storage" scenario that investments in gas networks will significantly decrease. The expansion of the transmission gas networks will only take place at very selective locations (e.g. connections to storage facilities and PtG plants). The total investment for new construction, expansion and retention of the networks shall only occur where a residual transport network remains necessary. Investments in new construction and expansion and in retaining distribution grids will be completely avoided. Annual investment costs will accordingly decrease to EUR 163 million in 2050 (compared to EUR 1.61 billion in 2015).

For maintaining and servicing transmission networks, a reduction in costs of approximately 50 per cent can be expected due to a 2/3 reduction in the length of the network to be maintained. In the distribution network, the cost of managing and securing decommissioned distribution networks comprises 10 per cent of the 2015 maintenance costs. In total, annual maintenance and servicing costs will decrease to around EUR 300 million in 2050 (compared to EUR 1.57 billion in 2015).

[27] One-time costs as based on costs in 2015.

[28] One-time costs as based on costs in 2015.

Effects on the gas network in the "Electricity and green gas" scenario

The existing gas networks can continue to be largely used in the "Electricity and green gas" scenario. Gas networks previously designed for natural gas can be converted to transport "green gases" at a reasonable expense. In this regard, the gas industry has already gathered many years of experience operating municipal gas networks, which were largely operated on hydrogen before being completely converted to natural gas in the late 1990s. The gas quality conversion from low calorific (L) to high calorific (H) gas, which is currently underway, also demonstrates the feasibility of such a change in gas quality.

Further expanding the gas networks to deliver energy from where it is produced to the end consumer is not necessary due to assumptions made in the scenario (e.g. new developments in the heat market, particularly through heat pump solutions). Instead, adjustments to the networks previously designed for natural gas must be made for gas containing hydrogen.[29]

The German gas network has historically been designed to accommodate a range of gas qualities and features parallel pipelines (including loop lines) in many areas. These could be decoupled in future and used to deploy a range of solutions. Accordingly, a separate hydrogen network could be inexpensively created to supply industrial customers and power plants using pre-existing redundant lines in current pipeline systems. A costly conversion of all household customers to hydrogen can thus be avoided.

4.2.4 Generation and conversion of electricity: slightly higher costs due to PtG conversion losses, which are predominantly offset by improved utilisation of renewables

This section presents:

- our analytical approach for using a European electricity market model to determine the required electricity generation and its costs; and
- our results.

Further details can be found in ANNEX E.

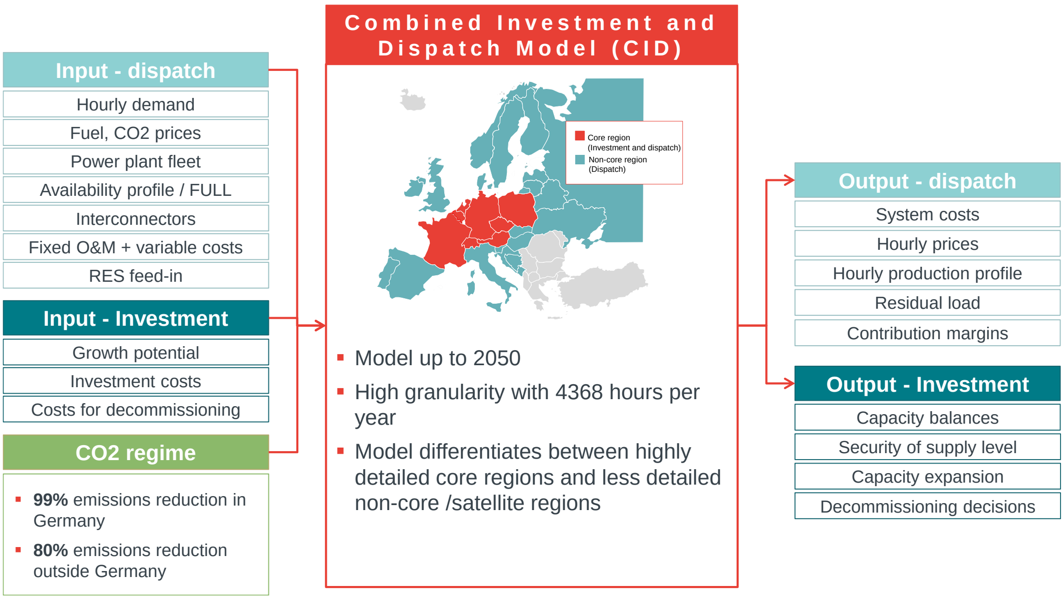
European electricity market model as the core of the analysis

Our analysis of generating and converting electricity are based on an European electricity market model (**Figure 26**). The model endogenously optimises the investment and operational decisions for power plants in the model region up until the year 2050 for both the "Electricity and gas storage" and "Electricity and green gas" scenarios. The model's main goal is to supply the hourly demand for electricity at minimal cost while taking into consideration the climate protection

29 In essence, the existing compressor systems need to be adapted to the higher compressor capacities and the changed thermal properties caused by the lower energy content of hydrogen or hydrogen-containing gases as well as to the measuring technology used for issuing bills.

goals in Germany as well as in other European countries.[30] Further details on the assumptions made within the electricity market model can be found in ANNEX E.

Figure 26 Overview of the model logic



Source: Frontier Economics

Gas demand and optimised investments in power-to-gas plants

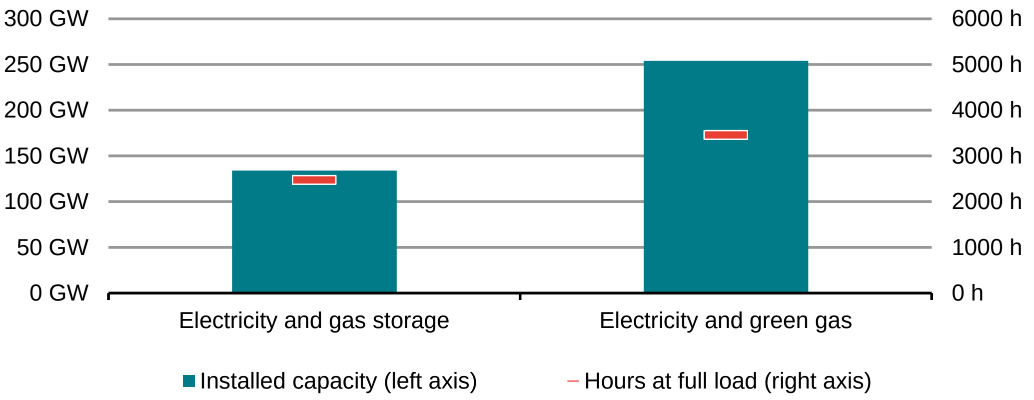
As well as meeting the electricity demand, the model must also meet the demand for green gas. This demand arises due to:

- the model's exogenous demand for green gas from heating applications, mobility and industry (0 TWh in the "Electricity and gas storage" scenario, 645 TWh in the "Electricity and green gas" scenario); and
- the model's endogenous demand for green gas for reconversion to electricity.

To meet the green gas demand, power-to-gas systems must accordingly be added and operated within the model. The construction and use of the PtG plants are optimised endogenously in the model. In the case of electricity, the entire portfolio of (renewable) generation plants, (reverse) conversion of gas through power plants, electricity storage options (pumped hydro and battery storage) and measures to promote further flexibility of demand are taken into account and examined with cost optimisation in mind.

[30] We assume a 99 per cent reduction in emissions in the generation of electricity in Germany and an 80 per cent reduction in emissions in other European countries.

Figure 27 Required power-to-gas plants and capacity utilisation in 2050



Source: Frontier Economics

Results: System costs compared for the scenarios

The key result of the electricity market model is the system costs of producing and converting electricity. The system costs consider all the significant costs incurred from generating and converting electricity:

- Investment costs in electricity generation plants and PtG plants;
- Fixed operating costs for electricity generation plants and PtG plants;
- Variable production costs for electricity generation plants and PtG plants;
- Costs/revenues from importing/exporting electricity; and
- Costs of decommissioning and reactivating power plants.

Since investments are made at different times and the investments have different lifetimes, the system costs are calculated as an annual annuity for the year 2050. The figure thus reflects the capital and operating costs for generating and converting electricity incurred in 2050 (2015 figures).

Due to energy-efficient end-user applications (especially heat pumps and electric cars) and lower conversion losses, the "Electricity and gas storage" scenario has a lower energy demand than the "Electricity and green gas" scenario. In addition, there are no ongoing costs for the synthesis of gas (particularly with regards to CO_2), which leads to lower annual costs amounting to EUR 4.2 billion for generating and converting electricity in the 'Electricity and gas storage' scenario compared to the "Electricity and green gas" scenario.

Due to the significantly more volatile load, however, generation capacities cannot be fully utilised in the "Electricity and gas storage" scenario, which means that this scenario requires a greater investment in generation capacities (see below). As a result, the total investment by 2050 (including PtG plants) in both scenarios is approximately the same, with EUR 478.3 billion required in the "Electricity and gas storage" scenario and EUR 475.8 billion in the "Electricity and green gas" scenario.

> "Similarly high investment costs for generating and converting electricity in scenarios with and without gas networks

Several conclusions can be drawn from the results:

"Electricity and gas storage" uses power-to-gas plants and gas-fired power stations to generate electricity in winter as well as during dark periods with little wind.

While in the "Electricity and green gas" scenario power-to-gas plants are mainly employed to satisfy the final energy demand with the possibility of reconversion almost redundant, the "Electricity and gas storage" scenario shows quite the opposite.

The high seasonal demand for electricity combined with the need to supply power during a dark period with little wind in the "Electricity and gas storage" scenario (see **Figure 12** page 20) results in the need for a flexible power generation system. For this purpose, a total of 243 TWh of green gas will be generated by PtG plants in 2050, which will be converted back into electricity via gas power plants in times of high electricity demand and low availability of renewable energy. In contrast, there is hardly any gas reconversion in the "Electricity and green gas" scenario due to the fact that most seasonal final energy consumption (especially for gas-based heat applications) is supplied by green gas. PtG plants tend to be in operation whenever more electricity is generated from renewable energy than is demanded by end consumers. When the supply of renewable energy is lacking, however, PtG plants are not operated and help relieve the burden on the electricity system as flexible loads.

> "The flexibility of the PtG plants relieves the burden on the electricity system

"Electricity and gas storage" requires additional generating capacities to secure supply against dark periods with low wind

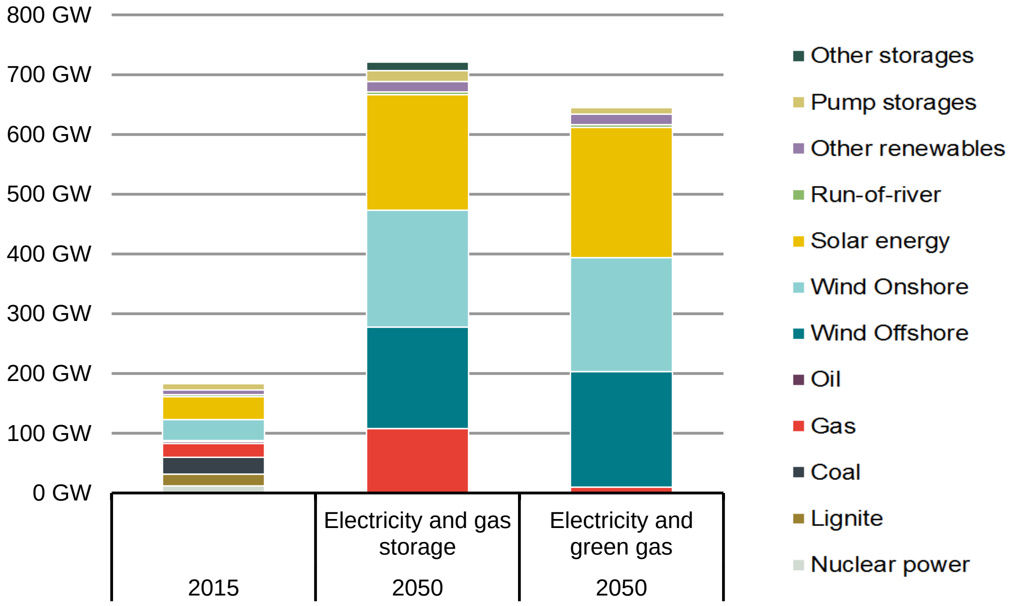
Both scenarios impose considerable demands on the energy system and require enormous generation capacities of wind and PV facilities, with both scenarios requiring more than 600 GW of renewable energy capacity. A comparison of the scenarios shows that roughly comparable RES capacities are required. While the "Electricity and gas storage" scenario requires 5 GW (2.5% more than for the

"Electricity and Green Gas" scenario) of additional on-shore wind plants to be built, the "Electricity and green gas" scenario uses an additional 23 GW of off-shore wind (14% more than the "Electricity and gas storage" scenario) and 25 GW more solar energy generating capacity (13% more than the "Electricity and gas storage" scenario) to meet the additional electricity demand for the power-to-gas plants.

In contrast, an additional 100 GW of gas fired power plants will be required in the "Electricity and gas storage" scenario to secure the electricity supply during dark periods with little wind by reconverting green gas to electricity. Furthermore, additional – expensive – electricity storage needs to be developed and the potential for demand-side response must be increased to provide flexibility to meet peak loads. **All in all, a significantly higher capacity of electricity generation (renewables plus gas fired power plants) is required in the scenario without gas networks, despite the possibility to temporarily store gas via PtGtP.**

> A significantly higher capacity of electricity generation is required in the scenario without gas networks

Figure 28 Generating capacities in 2015 and 2050 for each scenario



Source: Frontier Economics

The lower available capacity in the "Electricity and green gas" scenario does not fully compensate for the additional generation costs for PtG

By comparing the annual system costs of both systems for 2050, it can be seen that although the "Electricity and green gas" scenario requires lower generation capacities, this does not fully offset the cost disadvantage of higher overall electricity demand caused by conversion losses. This is because variable operating costs are higher in the "Electricity and green gas" scenario due to the higher requirement for methanisation and any associated costs for obtaining CO_2 as they are for the "Electricity and gas storage" scenario.

Viewed independently, the net system costs of the electricity generation system in the "Electricity and gas storage" scenario are lower than those in the "Electricity and green gas" scenario. The difference amounts to EUR 4.2 billion annually by around 2050.

> CO_2 supply for methanisation is the costliest element for green gas

One reason for the cost advantage of the "Electricity and gas storage" scenario which does not use the gas network is that the energy efficiency benefits of greater end-user electrification are reflected here. The higher investment costs associated with end-user applications (EUR 10 billion per year) and the additional costs required to expand the electricity network as a result of greater demand (EUR 6.3 billion per year) were each previously determined separately in the costs for end user applications (**Section 4.2.2**) and electricity network expansion (**Section 4.2.2**). Clearly these other costs are included in the comparison of system wide costs for each scenario.

4.3 Use of gas networks increases public acceptance of the energy transition

As well as the purely monetary benefits shown in the previous section, the (continued) use of gas networks offers several other benefits. The public's acceptance, particularly when expanding the electricity network, is a vital prerequisite for the success of the energy transition. Using gas networks within the energy transition can significantly increase public acceptance of the transition.

Lack of acceptance has already led to significant delays in network expansion

Conversely, a lack of public acceptance, particularly with regard to the urgently required expansion of the electricity network, could quickly put an end to the energy transition:

- The need to significantly expand the electricity transmission network has been known now for many years. While the majority of Germany's population sees the energy transition as very positive and supports it, concrete electricity network expansion projects regularly encounter significant – and individually quite understandable – opposition in the regions directly affected due to fears about effects on health and economic disadvantages, especially in the case of overhead cabling.

- As a result, almost all major projects involved in the expansion of the electricity network have been significantly delayed in recent years. Several legislative attempts to accelerate network expansion have been unsuccessful to date, including the adoption of the Energy Line Extension Act (EnLAG) in 2009 and the Network Expansion Acceleration Act (NABEG) in 2011. Delays in expanding the electricity network have already caused network operators to call for electricity generation plants and consumers to reduce or increase their generation or consumption of electricity ("redispatch") for 329 days per year (2016) to overcome existing network bottlenecks. Also, 3.7 TWh of renewable energy had to be curtailed due to a lack of sufficient electricity networks ("feed-in management"). This results in overall costs of EUR 783 million per year for redispatch and feed-in management.[31] The Federal Network Agency calculates that these costs will increase to EUR 4 billion by 2023.[32]
- Bavaria provides a well-known example of a lack of acceptance to expand the electricity network. The state government's opposition to planned direct current lines in December 2015 sparked the adoption of an "underground power cabling" law at the federal level, which stipulates that all required high-voltage direct current transmission lines (HVDC) be primarily implemented as underground cabling instead of as overhead lines to promote acceptance. This attempt to increase acceptance is costly. The Federal Ministry of Economics and Energy estimates the additional costs of planned partial cabling of the direct current lines at around EUR 3 to 8 billion.[33] Furthermore, this priority rule for underground cable will lead to further delays, since the planning of the projects had to be set back significantly, without local acceptance necessarily secured by this switch to underground cables.

In future, electrification will require even greater network expansion and a lack of acceptance threatens to block the energy transition.

The need to expand the electricity network identified in the course of developing the network development plan in recent years is mainly the result of a shift in the electricity production structure, for example, due to decommissioning of nuclear power plants in Southern Germany and the growing capacity of wind turbines in Northern Germany. An additional need to significantly expand the network will, however, occur in the process of directly electrifying end-user applications, such as electric vehicles and electricity-based heaters.

> “
>
> Using gas networks reduces the expansion of the electricity transmission network by around 40 per cent and the electricity distribution network by 60 per cent

Our electricity network model shows that using the gas network in the "Electricity and green gas" scenario between 2035 and 2050 avoids the need to expand the

[31] See Federal Network Agency (2017).

[32] See Federal Ministry of Economics and Energy (2016).

[33] Cf. http://www.zeit.de/wirtschaft/2015-10/energiewende-erdkabel-bundeskabinett.

electricity network by 17,800 kilometres of transmission lines (compared to 35,000 kilometres of electricity transmission lines today, plus the implementation of all NDP electricity measures assumed in both scenarios) and 500,000 kilometres of distribution lines (compared to 1.7 million kilometres of electricity distribution lines today).

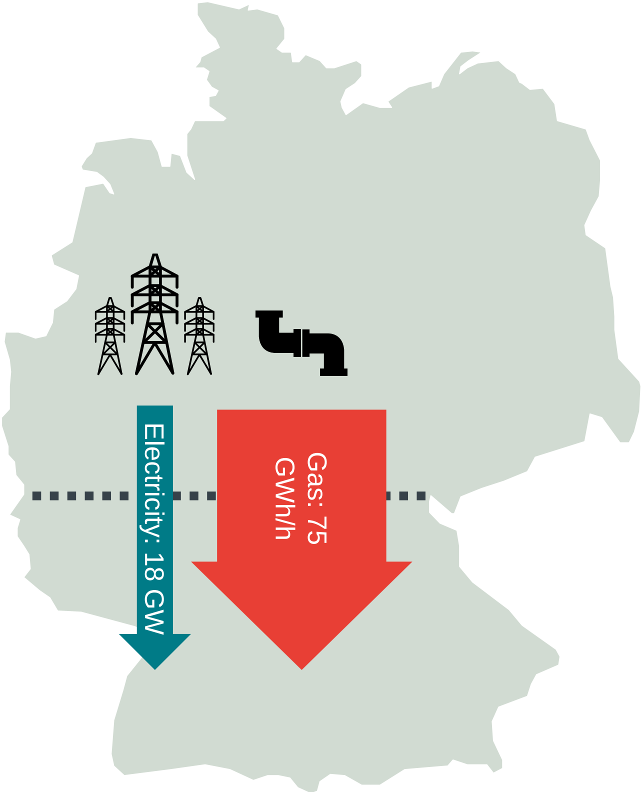
The gas infrastructure is already in the ground and can be used to transport energy in bulk without any acceptance problems

Conversely, the comprehensive gas infrastructure to satisfy the required supply of heat and industrial needs already exists. Both gas transmission and distribution networks are laid underground and are designed in such a manner, in combination with the large gas storage volumes, to supply today's gas demand. This is also sufficient to meet the forecast demand for green gas in 2050, however extreme the weather conditions.

Figure 29 illustrates that even today the gas transmission network can deliver more than four times as much power compared to the electricity transmission network in future, particularly along the crucial north-south transportation corridor.

In an energy system based on transporting electricity in accordance with the "Electricity-only" and "Electricity and gas storage" scenarios, the use of pre-existing and efficient gas infrastructure with wide public acceptance would not be required or the infrastructure would be partially physically dismantled. Instead, the electricity networks which are poorly accepted by the public would need to be significantly expanded. As a result, this situation may be increasingly difficult to achieve in terms of overcoming local resistance in the affected regions.

Figure 29 Comparison of pre-existing north-south transport capacities for electricity and gas



Source: Frontier Economics

Gas infrastructure offers acceptance advantages in the case of end-user applications

> Green gas paves the way to immediately roll out decarbonisation in the heat sector without having to exchange end-user devices

Despite a clear acceptance problem in relation to the network, the energy transition also undeniably depends on customers being willing to cooperate in terms of end-use applications for energy. If nothing else, the slow pick up of electromobility or of the modernisation of the heat sector shows that existing obstacles to consumers abandoning their usual habits and tried and tested end-user devices should not be underestimated. Particularly, since changing is often associated with high investment costs. In addition, certain existing solutions cannot be used at all, for example, installing heat pumps in existing buildings often requires extensive refitting to be able to adapt the heat system to the low flow temperatures required for efficient operation.

A lack of broad acceptance for such measures could help to block the energy transition in the same way as opposition to network expansion. The use of green gas can help here too. It enables, for example, established technologies such as gas boilers to directly begin decarbonisation in the heat sector, sometimes even using existing equipment (i.e. eliminating the need to change appliances).[34]

4.4 Use of the gas infrastructure boosts supply security of the energy system

In addition to the above illustrated advantages of better acceptance, another decisive advantage of gas infrastructure lies in its contribution to security of energy supply. This stems directly from the high energy density of gas and allows for:

- efficient storage; and
- high transport capacities even over great (up to global) distances.

The storage options for gas exceed those of electricity many times over

The retention of the gas infrastructure with its gas storage systems makes it possible to store energy with a high density. This increases the energy storage potential significantly and thus also enables the seasonal storage of energy. For example, pre-existing gas storage facilities in Germany already have a storage volume of around 260 TWh (which is equivalent to more than 30 per cent of annual gas demand). In comparison, the storage volume of all German pumped storage facilities in the electricity system is only about 0.04 TWh.[35] The storage capacity of German pumped storage power plants today suffices to meet the average electricity demand for 41 minutes.[36] Please also see **Section 3**.

The gas infrastructure offers many import options

In the case of German energy supply, the aim is not to meet the entire energy demand from production located in Germany, but to use the existing efficient network of import pipelines to utilise cheaper energy sources from abroad or to export surplus energy. Furthermore, the gas infrastructure can also be used to ensure the energy supply at critical times via imports.

This possibility was not taken into account in the calculations we presented in the previous sections. Instead, for simplification and to take a conservative approach, we assume the green gas required to supply the demand for final consumption must be entirely produced in Germany.

The potential to import and export gas therefore represents an additional option as yet unconsidered when calculating the system costs in **Section 4.2** for increasing the security of supply (and reducing the system costs).

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[34] In the process of calculating the end-user application costs in **Section 4.2.1**, a conservative assumption has been made that every end-user device (e.g. existing gas boilers) will have to be replaced (at least) once between today and 2050. The advantage of being able to partially use existing end-user devices when using green gas (particularly methane) was therefore ignored in this analysis of long-term perspectives.

[35] Gas storage volume is according to Gas Infrastructure Europe, storage capacity of pumped hydro storage systems is according to the German Bundestag (2017), p. 8.

[36] Based on annual electricity demand of 521 TWh.

Especially in view of the international climate protection goals, the high-energy density and the established international and partially global transport infrastructure (pipeline and LNG supply chains), it can be assumed that CO_2-neutral gases (and fuels) will form a global market in the long term.

> Use of green gas can also help diversify energy sources

This would allow Germany to benefit from significantly lower production costs for renewable energy in other countries (e.g. water-rich Scandinavia) and boost supply security by diversifying energy sources.

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ANNEX A DETAILS FOR DERIVING THE FINAL ENERGY DEMAND 2050

Beyond the remarks in **Section 2.3**, this Annex provides further details about how the exogenous demand for electricity and gas for 2050, which is used as input data for the model, is derived from the 2015 German energy balance.

A.1 Deriving the end-use energy in 2050

Space heating in households and the service sector as well as industrial process heat and mobility were identified as the largest consumption groups based on Germany's energy demand in 2015 (cf. **Figure 7** on page 15).

How the energy consumption for these groups develops by 2050 is subject to great uncertainty and influenced by various economic, technological and demographic factors. To ensure comparability to other studies, we have refrained from doing our own energy demand forecast. Instead our assumptions are based on data provided by different studies of established institutions:

- **Space heating and hot water** – Predictions about the savings potential for the space heating and hot water sectors are made based on information provided by Fraunhofer (2015). The assumptions here include:
  - A 9 per cent reduction in demand for heating in 2050 (compared to 2008) caused mainly by replacing old flats and houses by new ones;
  - A renovation rate of two per cent that sparks a 25 per cent reduction in the demand for heating in 2050 as compared to 2008;
  - The influence of climate change is also included, causing a further 16 per cent decline in demand for heating as compared to 2008.

  Overall, the savings from 2015 to 2050 amount to 34 per cent. This savings potential is used in our calculations for both space heating and hot water in all sectors.

- **Process heat** – The development of the energy demand for process heat is based on studies by Fraunhofer (2015) and DLR (2012). Fraunhofer (2015) and DLR (2012) themselves do not conduct a bottom-up analysis of the development of the demand for process heat in individual industries, but differentiate between various temperature levels. The studies stipulate a 30 per cent decline in the energy demand for process heat across all temperature variation levels from 2008 to 2050.

  Therefore we assume that the end-use energy demand for industrial processes will decrease by 25 per cent from 2015 to 2050.

- **Mobility supply** – For final energy demand for mobility we base our assumptions on traffic and transportation volume expected by the German Federal Environment Agency (2016) in different scenarios for 2050. In the case of rail transport, data from the Fraunhofer (2015) study is used since the study conducted by the German Federal Environment Agency (2016) does not consider traffic and transportation volumes in this sector. In total, traffic and transportation volume is increasing significantly.

The assumptions made so far do not focus on specific technologies and therefore do not differ in our scenarios. End consumers thus have the same amount of end-use energy (i.e. the same amount of space heating, process heat, hot water, traffic and transport volume) in all scenarios, no matter what type of technology is used. Thus we ensure comparability of the scenarios.

A.2 Determining final energy demand by considering scenario-specific end-applications

The resulting final energy demand and the breakdown of the various energy sources are ultimately a result of the application technologies used in the respective scenarios.

For both the "Electricity-only" and "Electricity and gas storage" scenarios, the assumption is made that gas-based end-consumer applications are not available. Instead, either electricity or imported climate-neutral liquid fuels are used. In the "Electricity and green gas" scenario, however, part of the energy will be supplied via green gas and thus gas-based applications are used.

In the following, we explain which end-user applications we assume for space heating, process heat and mobility in the individual scenarios:

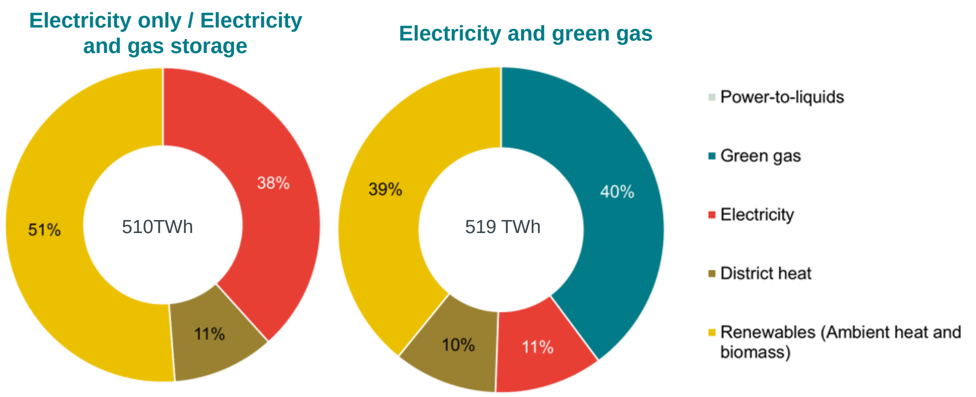
- **Heat supply** – In both scenarios, we assume that a significant share of heat demand is provided by heat pumps. Both scenarios also similarly exploit district heating and the direct burning of renewable energies such as biomass.

  The scenarios differ, in particular, to the extent to which heat pumps and gas-based technologies are used:

  - For example, the share of heat pumps used in the "Electricity only" and the "Electricity and gas storage" scenarios is higher. Since heat pumps cannot be efficiently installed in all existing buildings, these scenarios assume that some buildings also have direct electricity heating.
  - In contrast, the share of heat pumps in the "Electricity and green gas" scenario is slightly lower than in the other scenarios and thus heat supply in this scenario remains reliant on gas-based heating technologies.

  Figure 30 illustrates the resulting breakdown in final energy demand separated by energy sources.

Figure 30 Energy split for space heating and warm water in 2050



Source: Frontier Economics

- **Mobility –** In the mobility sector, both scenarios assume that rail transport will be fully electrified and that aviation, shipping and 50 per cent of the transport volume in road traffic will be fuelled by climate-neutral liquid fuels ("power-to-liquids"). We assume that climate-neutral fuels can be imported from other countries and therefore need not be produced in Germany (in contrast to synthetic gas, which we assume to be produced in Germany to take a conservative approach, see above).

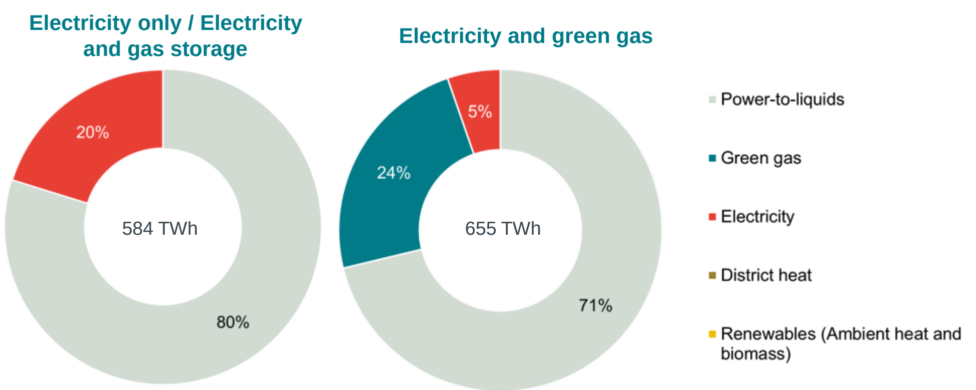
  In the mobility sector, the scenarios therefore only differ in terms of the configuration of the share of road transport that is not fuelled by climate-neutral fuels:

  - In the "Electricity-only"/"Electricity and gas storage" scenarios, this share is exclusively provided by battery-electric vehicles.
  - In the "Electricity and green gas" scenario, battery-electric vehicles provide only a smaller portion of this share. In addition, gas-powered drives, in particular fuel cells (that use hydrogen), are also used here.

  See ANNEX B.1 for further information on transport.

  Figure 31 illustrates the resulting breakdown in final energy demand breakdown by energy sources.

Figure 31 Energy split for mobility in 2050

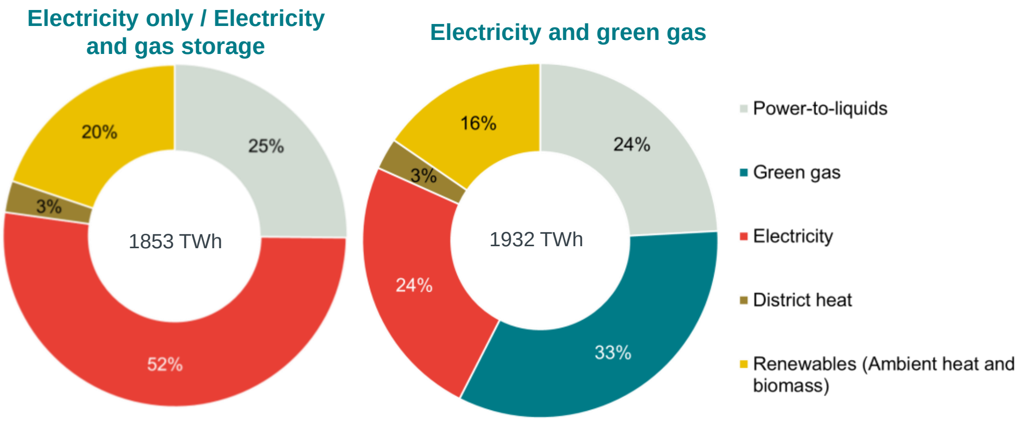


Source: Frontier Economics

The scenario-specific final energy demand is a result of efficiency gains as described earlier and the technologies used (cf. **Figure 9** on page 18). Due to the different technologies used and their differing degrees of efficiency, the final energy demand varies in all scenarios, despite the equal end-use energy requirements:

- In the "Electricity-only" and "Electricity and green gas" scenarios the final energy demand to be supplied in 2050 is 1,853 TWh.[37] The breakdown by energy sources is as follows (**Figure 32**):
  - 3 per cent district heating based primarily on the use of waste heat and biomass;
  - 20 per cent direct renewable energy, mainly from ambient heat;
  - 25 per cent synthetic liquid fuels imported from other countries; and
  - 52 per cent electricity.[38]
- In the "Electricity and green gas" scenario the final energy demand to be supplied in 2050 is 1,932 TWh. The breakdown by energy sources is as follows (**Figure 32**):
  - 3 per cent district heating based primarily on the use of waste heat and biomass;
  - 16 per cent direct renewable energy, mainly from ambient heat;
  - 24 per cent synthetic liquid fuels imported from other countries;
  - 24 per cent electricity[39]; and
  - 33 per cent domestically produced synthetic gases ("green gas").

Figure 32 Final energy breakdown in 2050 in the scenarios



Source: Frontier Economics

Note: Storage and conversion losses not yet included

37 A decrease of approx. 25 per cent as compared to 2015.

38 Any conversion and storage losses resulting from different storage technologies are not included here.

39 Any conversion and storage losses resulting from different storage technologies are not included here.

ANNEX B DETAILS ON THE ANALYSIS OF END-USER APPLICATION COSTS

Beyond the remarks in **Section 4.2.1**, this Annex provides further details about how the scenario-specific costs for end-user applications are determined.

In accordance with our focus on the end-use applications with the largest energy demand, the methodology for determining end-user application costs in the transport and heat sectors is outlined in detail below.

In addition to the total investment, we also determine annuities for 2050 based on the respective lifetimes of the technologies to ensure comparability in view of the differing usage and depreciation periods of the various devices.

B.1 Transport

Cost differences between the scenarios only exist for road traffic due to the assumption of using consistent energy sources for the other areas in both scenarios. For the "Electricity and gas storage" scenario, the additional costs amount to EUR 1.6 billion per year by 2050. We differentiate between cars, trucks and public buses. The costs are calculated using the

- number of vehicles and
- unit prices for the corresponding vehicles.

To calculate annuities, we assume that all cars last 20 years (this roughly corresponds to twice the average age of 9.3 years[40] for all cars registered as of 1 January 2017).

Number of vehicles

The number of vehicles in 2050 is derived from the current number of cars, trucks and buses[41] and the increase in passenger kilometres.[42] The total number of units increases from 55.5 million today to 63.3 million by 2050. We assign the total number of car, truck and bus units to energy sources in accordance with the breakdown provided in Annex A.2 (electric, gas/hydrogen or liquid climate-neutral fuels):

- In both scenarios, 50 per cent of the vehicles run on liquid climate-neutral fuels.
- In the "Electricity and gas storage" scenario the residual 50 per cent of the vehicles are powered electrically.

[40] Cf. Federal Motor Transport Authority http://www.kba.de/DE/Statistik/Fahrzeuge/Bestand/Fahrzeugalter/fahrzeugalter_node.html

[41] Cf. Federal Motor Transport Authority https://www.kba.de/DE/Statistik/Fahrzeuge/Bestand/FahrzeugklassenAufbauarten/2017_b_fzkl_eckdaten_pkw_dusl.html

[42] Cf. Federal Environment Agency (2016)

- In the "Electricity and green gas" scenario only 20 per cent of the residual 50 per cent of the vehicles are powered electrically. All other vehicles are powered by gas/hydrogen.

Unit prices of the vehicles

Based on current information, the unit prices for the different technologies will be cheaper in 2050 than today. We base our cost assumptions on assumptions made in third-party studies (see table below):

Figure 33 End-user application costs in transport

Vehicle category	Vehicle	2050 unit costs in EUR	Source
Car	BEV	26,000	Fraunhofer 2015b
	Gas/H2 combustion motor	24,968	Federal Environment Agency 2016
Truck	BEV	106,822	Fraunhofer 2015b
	H2 fuel cells	106,310	Fraunhofer 2015b
Bus	BEV	213,774	Federal Environment Agency 2016
	H2 fuel cells	212,881	Federal Environment Agency 2016

Note: Vehicles that run on hydrogen are defined as gas/H2 combustion engines for cars and fuel cells for trucks and public buses. Our assessment is based on the Federal Environment Agency's view (2016) [43] that the use of PtG-H2 in fuel cell vehicles is associated with the highest costs per vehicle in the case of low mileage.

B.2 Heating applications

The technological costs of heating applications are divided into the households, TCS and industrial sectors, as well as applications for space heating, hot water and process heat. The costs are calculated from

- the per-kW technology costs in 2050 and
- the capacity in kW of the technology required in each scenario to deliver the end-use energy.

Costs of heating applications in EUR/kW

One of the main factors generating additional costs in the "Electricity and gas storage" scenario is the cost of purchasing the electric heat pumps. Conversely, assuming that the shares for district heating, solar thermal energy and incineration of renewable energies such as wood pellets are equal in all scenarios, these do not contribute to the difference in costs between the scenarios. The relevant cost assumptions are shown in the following table.

[43] Cf. Federal Environment Agency (2016), p. 4

Figure 34 Relevant end-user application costs in the heating sector

End-user applications	Costs 2050 in EUR/kW	Sources
Direct electric heating	103	Fraunhofer 2015a
Electric heat pumps	3,500	Fraunhofer 2015a
Micro-cogeneration plants	1,500	Fraunhofer 2015a
Gas boilers	350	Fraunhofer 2015a
Combined heat and power plants	650	Fraunhofer 2015a

The industrial sector distinguishes between low temperatures (up to 100°C) and medium and high temperatures (100-500°C and> 500°C, respectively). While heat pumps, gas boilers or electric heaters such as electrode boilers are used at low temperatures, we assume that for most medium- and high-temperature processes the additional costs for electric-based processes will not exceed those of an alternative supply of processes with decentralised gas produced by electrolysis, for which the same (conservative) cost assumptions have been made as for the central power-to-gas production (EUR 250/kW).

Capacity of the technologies in kW

We determine the capacity of the technologies based on the following two steps:

- **The basis is the energy required in kWh resulting from the scenario assumptions**. For this purpose, we use the final energy demand described in Annex A for 2050. This specifies for all scenarios how much energy is needed in kWh for which form of technology, while taking technology-specific conversion losses into consideration.
- **To derive at kW numbers we take load profiles into consideration**. Thus we use corresponding load profiles for electric heating systems and heat pumps to derive the capacity required for the work demanded.

ANNEX C DETAILS FOR DETERMINING THE ELECTRICITY NETWORK COSTS

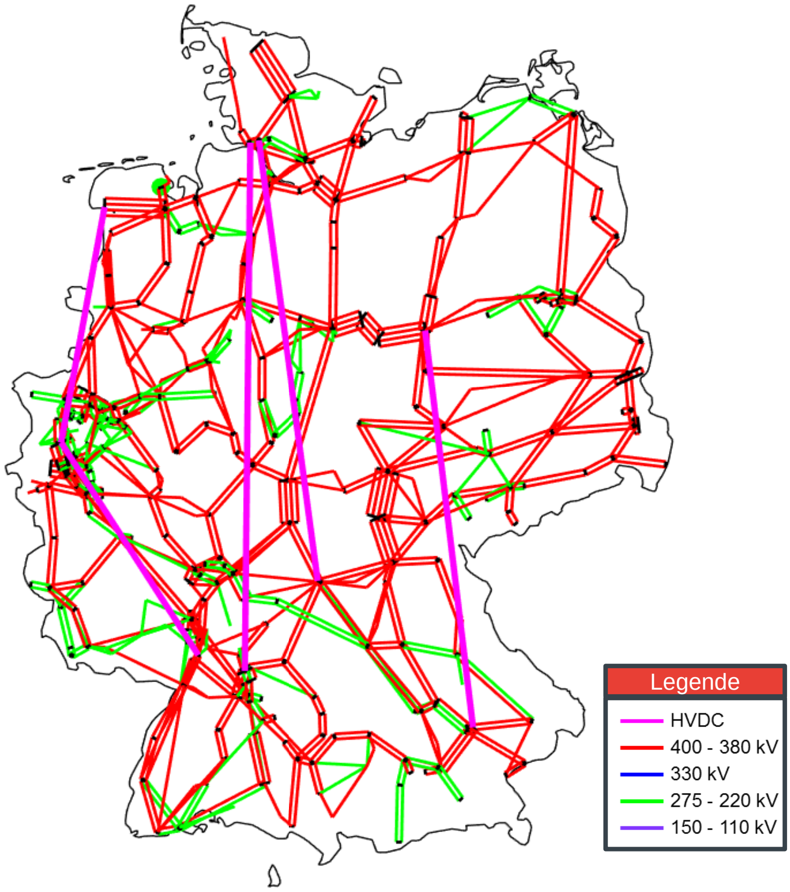
Beyond the remarks in **Section 4.2.2**, this Annex provides further details about how the scenario-specific costs for the electricity networks are determined, including differentiation between transmission and distribution networks.

C.1 Transmission network model

This study used and further developed an existing transmission network model to factor in all network expansion projects from the Network Development Plan 2030 (NDP 2030) Scenario B that should be completed by 2035. The 2035 transmission network model created includes all HVDC transmission connections, as well as 220 and 380 kV AC network upgrading measures, but also newly built AC 380 kV- lines and busbars of the Network Development Plan. Equally, the measures stipulated in the "Ten Year Network Development Plan" 2016 (TYNDP 2016) were incorporated for the integrated European network.

The transmission network model planned for 2035 free of bottlenecks provides the starting point for quantifying the additional costs of projects for further expanding the network which arise in the 2050 scenarios considered. The network expansion costs up until 2035 are taken from the NDP 2030.

Figure 35 Used transmission network model for Germany according to NDP 2030 (scenario B)



Source: IAEW

Regionalisation of consumers, suppliers and PtG plants

To regionalise, we assign feed-in and load time series as well as power plant dispatch, which are presented in the market simulation on a market-area basis, to individual transmission network nodes to obtain a suitable basis for the network operation simulation. The resulting hourly and network node-oriented loads/feed-in situations serve as the input data for the following network operation simulation. We regionalise the different components as follows:

- **Load** – Distribution based on historical industrial locations and average population density per transmission network nodes.
- **Wind energy and photovoltaic power plants** – Consideration of the current locations based on the Federal Network Agency's registry of installations and scaling to the future capacity of the market model.
- **Other RES facilities and time series** – Distribution of other RES facilities and time series (e.g. CHP) according to current locations and distributions.
- **Power-to-gas plants** – Distribution of power-to-gas plants in all scenarios is proportional to the installed capacity of on-and off-shore wind power plants to relieve the grid of high wind feed-in.

- **Thermal power plants** – In principle, we add thermal power plants at locations where power plants of the same primary energy or, if no corresponding location exists, of other primary energy, were already located. The locations of historical power plants are recorded in the model for this purpose, which helps ensure the existing infrastructure can be used efficiently. The same distribution of gas power plants as for PtG plants is used for the "Electricity with gas storage" scenario, since the assumption is made that gas is not transported but instead that the same site is used for conversion. Power plant dispatch is determined specifically for each unit taking any technical constraints into consideration.

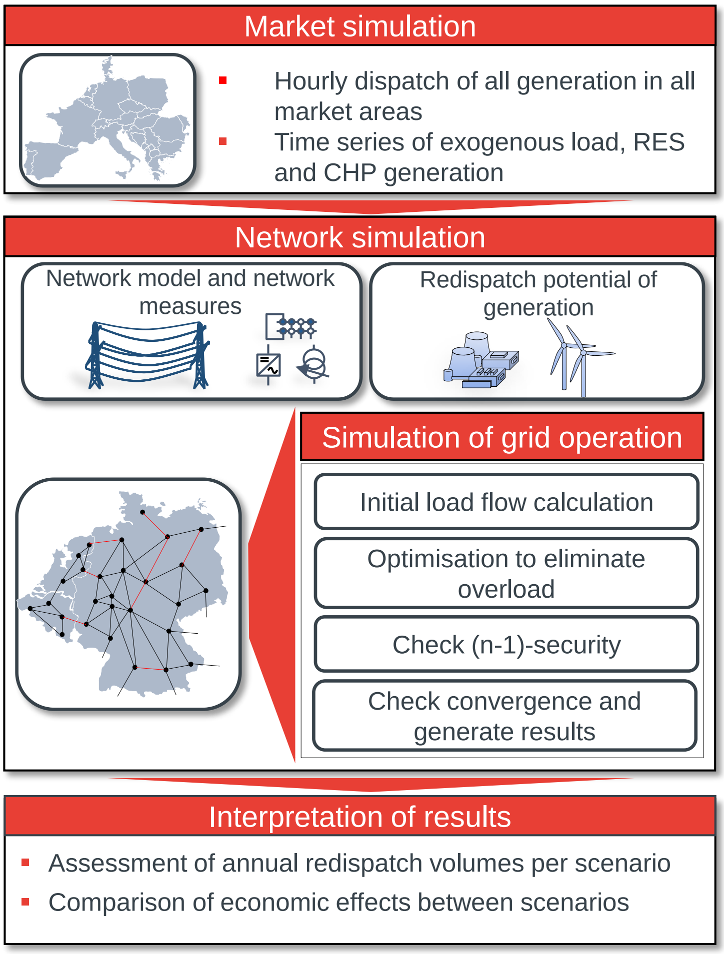
To determine network bottlenecks, the loads and feed-ins resolved on an hourly and per location basis for each transmission network node are used as input data for the subsequent network operation simulation.

C.2 Network operation simulation

The network operation simulation is used to check voltages and current limit values during normal or impaired operation of the (n-1) transmission network at hourly intervals and resolve any limit value violations using any network and generation/load-side degrees of flexibility.

From a mathematical perspective, determining the operating points of power-flow-controlling operating resources under the consideration of predefined limits represents what is referred to as a "Security-Constrained Optimal Power Flow" (SCOPF) problem. Problems such as these deal with the task of optimisation while also taking power flow equations into consideration. The solution to the SCOPF problem is provided by taking a successive approach with the overlapping coordination of the critical failure situations to be considered. To do this, relevant failure situations and resources are first identified through a (n-1) contingency analysis, which is then used to formulate and solve an (application-specific) linear or quadratic optimisation problem for the current operating level. It should be highlighted here that all linearisation is always performed at the current operating level and not pre-calculated, so that the network topology in time series calculations can be easily adjusted. The optimisation problem's solution is then used for the network model. To compensate for the non-linearities of the power flow problem, the optimisation process is then successively repeated on the basis of a new power flow calculation. We illustrate the process for the network operation simulation in Figure 36.

Figure 36 Flow chart of the network operation simulation



Source: IAEW

The results generated by the network operation simulation are plant-specific redispatch quantities, the necessary curtailment of RES facilities as well as the utilisation of electricity lines before and after bottleneck remediation measures. These parameters represent important indicators for identifying projects necessary for network expansion.

Only power-to-gas plants and HVDC connections were permitted as controllable degrees of flexibility in the network operation simulation. Any remaining bottlenecks after adapting these degrees of flexibility must be addressed by network expansion. Particularly, we do not allow for curtailment of RES facilities in the network operation simulation.

C.3 Estimation of transmission network expansion

A network expansion simulation is carried out to address the bottlenecks identified in the network operation simulation. Overloaded network operating resources are reinforced through an iterative process in the network expansion simulation. Using the initial network operation simulation, critical hours, lines and locations are identified and then factored into the expansion simulation. The following measures are taken into account for the expansion of the transmission capacities:

- **Network upgrading** of existing electrical circuits from 220 to 380 kV – If 220 kV electrical circuits overload, they will be replaced by 380 kV high-temperature conductors. The corresponding costs of converting switchgears and transformers are accounted for.
- **New construction** of 380 kV cables on existing lines – In the case of individual 380 kV electrical circuits overloading, we assume that a parallel 380 kV cable section will be expanded on the corresponding line.
- **Construction of HVDC connections** – As an alternative to the upgrading measures through AC cables, we allow for the expansion of high voltage DC connections. The locations for HVDC terminals are selected by identifying the sites with the greatest bottleneck-related change in capacity in the hours under consideration.

After each expansion iteration, new network operation simulations are performed for the critical hours to identify the remaining bottlenecks. The process is repeated iteratively until one of the following termination conditions is met:

- Bottleneck-free network for all hours of the year.
- Redispatch quantities of the individual hours of the year below a predefined limit (e.g. 100 MWh).
- For a defined number of critical hours, the total of all redispatch quantities falls below a predefined limit. (1 GWh was used as the limit for the scenarios examined).

The process is also terminated when between two expansion iterations the redispatch quantity does not exceed a pre-defined degree of improvement by adding new network operating resources.

To accelerate the simulation and avoid having to calculate excessive network use cases in the network operation simulation, we identify the 500 hours with the most critical network bottlenecks. The network expansion for these hours is then determined, thereby making it possible to identify the majority of network expansion measures. After the expansion simulation is completed, a subsequent annual simulation can be used to check whether further network expansion is necessary for the other hours.

The network expansion simulation can be used to approximate the necessary costs of expanding the network, the line lengths and the required number of operating resources for the scenarios under consideration. As a concrete result, the additional network operating resources are output according to type and number (HVDC terminals and HVDC cable sections, 380 kV cables, 380 kV overhead transmission lines, 380 kV busbars and 220 kV/380 kV transformers). The cost rates used correspond to those provided in NDP 2030. The process for simulating network expansion is summarised in Figure 39.

The lifetimes assumed for each type of component are listed in Figure 37. The values correspond to standard assumptions from the Electricity Network Fee Regulation Ordinance (Stromnetzentgeltverordnung) and are factored in when calculating the annuity costs. Due to the lack of data on the lifetimes of HVDC terminals and cables, we assume the same lifetimes for the DC network operating resources as for the AC scenario.

Figure 37 Lifetimes assumed for each type of network operating resource

Network operating resources	Useful life (in years) in accordance with Electricity Network Fee Regulation Ordinance and the allowance for depreciation table
380 kV AC overhead lines	40
380 kV AC cables	40
380/220 kV transformers	25
380 kV switchgears	25
DC cables	40
DC terminals	40

Source: IAEW

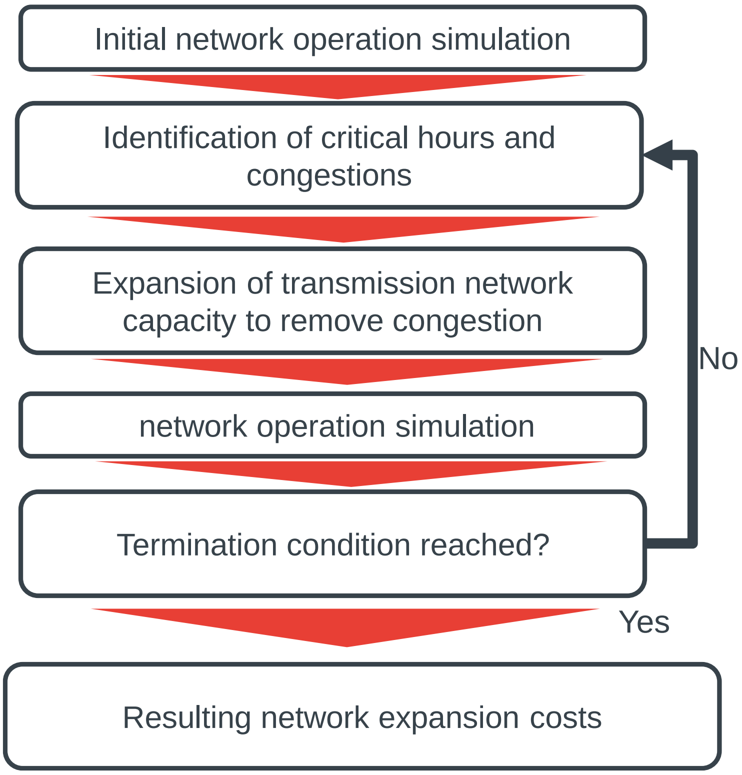
This is then used to divide the annuity costs based on the scenario and network operating resources (Figure 38). The annuity costs from NDP 2030 also have to be considered. A useful life of 40 years for all components is assumed here, resulting in annuity costs of EUR 1.09 billion per year.

Figure 38 Annuity costs broken down by scenario and networking operating resource (after 2035)

Network operating resources	Annuity costs [EUR billion/year]	
	"Electricity and gas storage" scenario	"Electricity and green gas" scenario
380 kV AC overhead lines	0.44	0.17
380 kV AC cables	1.88	0.93
380/220 kV transformers	0.03	0.02
380 kV switchgears	0.02	0.01
DC cables	0.46	0.20
DC terminals	0.42	0.23
Total	3.43	1.56

Source:IAEW

Figure 39 Flow chart of the network expansion simulation



Source: IAEW

C.4 Estimation of distribution network expansion

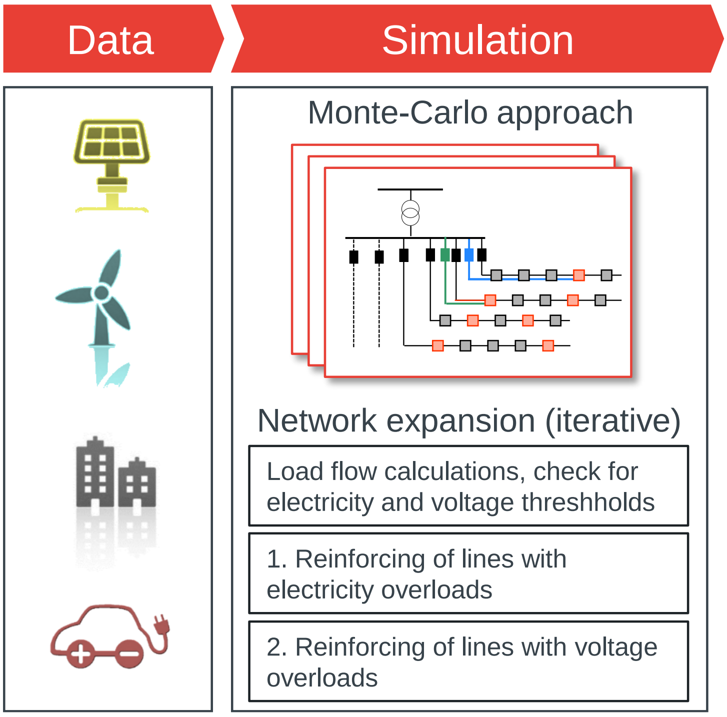
Due to the heterogeneity of the supply tasks and the existing network infrastructures at the distribution network level, we do not simulate the distribution network to a similar level of detail as the transmission network. To quantify the necessary network expansion, we apply a procedural approach based on the approach applied in the distribution network study for the Federal Ministry of Economics and Energy ("BMWi Verteilernetzstudie"). The distribution network requirements at the medium-voltage (MV) and low-voltage (LV) level in Germany are estimated by extrapolating the expansion requirements of individual model network classes.

As in the BMWi Verteilernetzstudie, we derive standard model network classes based on openly operated ring networks (MV) combined with medium-voltage and low-voltage line networks using the pre-existing network structure. The model network classes differ with regard to their supply task, the area to be supplied, the installed capacity of RES facilities and the peak load of the supply area. Regionally heterogenous supply tasks are reflected by using a wide spectrum of model network classes. Model network classes may also have different structural parameters, such as a different share of cables and overhead transmission lines for each network level.

We feed-in the assumptions made for the examined scenarios with regards to installed RES capacities and loads in 2050 for the network use cases for each distribution network level.

We then generate standard model networks for each model network class by using a Monte Carlo simulation where we vary the exact network structure parameters and the location of RES facilities and consumers in the network. Subsequently, for every stochastically determined model network we carry out a network expansion simulation and determine the necessary costs of expanding the network. We then identify the current- and voltage-related expansion measures for the network use cases. Thanks to the simulation, the anticipated value of network expansion costs for each model network class can be determined. Based on the approach used in the BMWi Verteilernetzstudie, the cost share of transformers is allocated as an extra cost to the low- and medium-voltage network expansion costs. The estimated nationwide network expansion costs in Germany are determined from the weighted sum of the expansion costs per model network class.

Figure 40 Procedure for determining network expansion for each network class



Source: IAEW

As illustrated in Figure 40, the development of the size-determining peak load that takes e-mobility, power-to-gas, power-to-heat as well as other decentralised flexibility options into account are, in addition to the installed capacities of the renewable energy facilities, included as input data in the network expansion simulation. We make the following assumptions with regard to the allocation of RES facilities at the distribution network level, the peak load and the use of flexibility options:

- Distribution of RES facilities at distribution network levels[44] (percentage figures refer to the total installed nominal capacity):

[44] Values are based on in-house evaluations of the registry of installations of the German Renewable Energy Act (EEG-Anlagenregister).

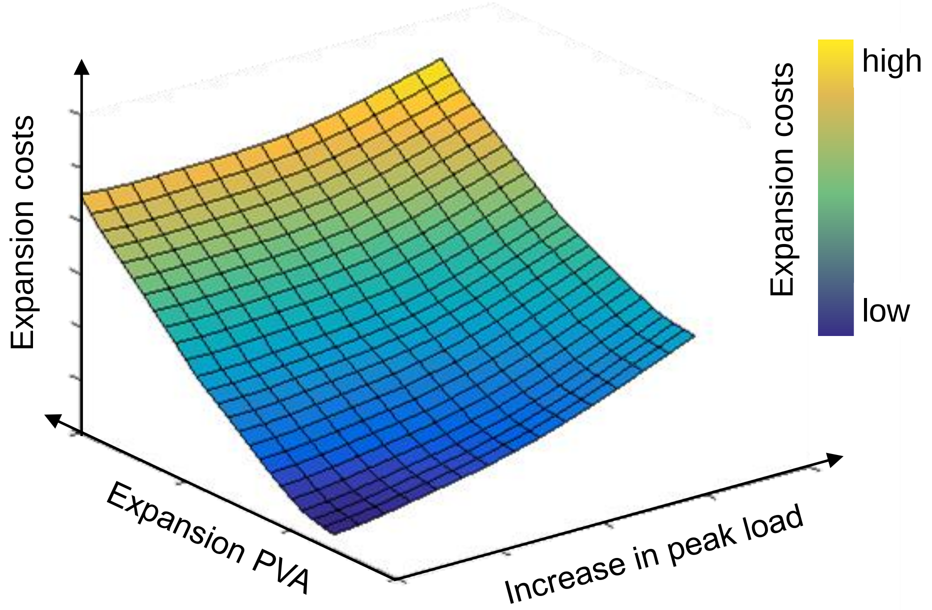
- 60 per cent of the on-shore wind power plants are connected to medium-voltage lines and 40 per cent to high-voltage lines.
- 72 per cent of the photovoltaic power plants are connected to low-voltage lines, 24 per cent to medium-voltage lines and 4 per cent to high-voltage lines, respectively.

- The possibility of distribution network operators considering peak capping in the network design is reflected:[45]
  - Wind energy plants are capped at 87 per cent of the installed generation capacity.
  - Photovoltaic power plants are capped at 70 per cent of the installed generation capacity.
- We assume that five per cent of the peak load occurring for each scenario can be reduced by network-compatible demand-side management (DSM),.
- We assume that 25 per cent of the PtG capacity is connected to the transmission network (e.g. to directly receive electricity from off-shore wind power plants) and 75 per cent of the PtG capacity is connected to the distribution network.
- We assume that 75 per cent of the PtG plants in the distribution network are located at sites with wind power plants and 25 per cent at sites with photovoltaic power plants.

Thanks to the network expansion simulation, the incremental increase in network expansion costs can be represented as a variation of the installed RES capacities as well as the peak load as shown in Figure 41. Using a table generated based on the presented procedure, we derive the total costs of network expansion can based on the assumptions made and the resulting network loads.

[45] Numerical values in line with the Forum Network Technology/Network Operation in the VDE (FNN); FNN-Hinweis: Spitzenkappung – ein neuer planerischer Freiheitsgrad. (FNN information: peak capping – a new degree of flexibility in network planning)

Figure 41 Development trajectories of network expansion costs



Analgous calculations exist for the expansion of wind installations

Source: IAEW

Figure 42 shows the lifetimes assumed for each component type to calculate annuity costs. The values correspond to the assumptions made in the BMWi Verteilernetzstudie.

Figure 42: Lifetimes of each network operating resource

Network operating resources	Assumed lifetimes (in years)
LV cables	40
MV cables	40
HV cables	40
HV/MV transformers	30
MV/LV transformers	30

Source: IAEW

ANNEX D DETAILS ON THE ANALYSIS OF GAS NETWORK COSTS

Beyond the remarks in **Section 4.2.3**, this Annex provides further details about how we determine the scenario-specific costs for gas networks. More than in other areas, our analyses are based on the current costs due to the fact that the gas networks do not undergo significant expansion in the scenarios but are instead preserved or dismantled.

The German gas network operators currently invest EUR 1.5 billion per year in expanding and retaining the transport and distribution network measuring nearly 500,000 kilometres in length. Gas network operators also spend a further EUR 1.5 billion per year to maintain the networks.

Figure 43 Expenses of gas network operators in 2015 (in EUR million)

	Transmission network	Distribution network	Total
Investments in new construction and network expansion	340.7	681.5	1,022.2
Investments in retaining and restoring networks	155.2	430.5	585.7
Costs of maintenance and servicing	365.5	1203	1,568.5
Total (Investments and costs)	**861.4**	**2,315**	**3,176.4**

Source: Monitoring report of the Federal Network Agency 2016 p. 276 ff

German gas networks do provide near-complete security of supply to end consumers in the private heat market in accordance with European[46] and German law[47]. The gas supply failure rates (SAIDI value 1.67 min/year [2015])[48] are far below the already very low failure rates of the German electricity network (SAIDI value: 12.7 min./year (2015)). The gas supply thus ensures a secure supply of heat for its customers, even during the coldest winters, in accordance with the required supply standard of EU Regulation 994/2010.

D.1 Estimation of dismantling costs

In the "Electricity and gas storage" scenario a large portion of the gas network is no longer required for use. Due to rights of way agreements concluded between gas network operators and property owners, these pipelines must – at the property owners' request – either be dismantled or, in the case of permanent decommissioning, secured in such as to ensure that the pipelines and plants concerned pose no permanent risk to the general public. As a result, dismantling costs arise here.

We base our calculations on the following key figures:

[46] Cf. Ordinance (EU) No. 994/2010 Art. 8 Para.1 – SGSO.

[47] Cf. § 53a EnWG (Energy Industry Act)

[48] Cf. Monitoring Report of Federal Network Agency p.

Figure 44 Need for dismantling in TSO network (without storage and international transit pipelines)

Inventory of plants		Proportion of dismantling measures [%]	Costs per unit [TEUR]/ [Km or unit]	Proportional demand for dismantling [%]
33,000 km[49]	Gas transport pipelines			
	Dismantling[50]	5%	800	70%
	Insulation and sealing[51]	30%	200	
	Sealing[52]	65%	20	
1,680 units	Gas pressure-regulating stations		75	88%
75 units	Large compressor plants		10,000	50%
75 units	Small compressor plants		1,000	50%

Source: FourManagement

A total of EUR 3.1 billion in decommissioning costs can be assumed for dismantling or securing of pipelines in the transmission network (approximately 22,500 kilometres).

Depending on contractual arrangements and at the request of the cities and municipalities, gas distribution network operators, whose rights of way for pipelines are usually covered by concession contracts concluded with the municipalities, will incur between EUR 20 and 150 billion in dismantling costs as a result of having to secure the 481,000 kilometre-long distribution network which will no longer be used. Due to ambiguous legal circumstances, a very conservative approach has been taken for our calculations for the networks of distribution network operators. Based on data supplied by TSO networks, only 35 per cent of the costs for pipelines were assumed due to the smaller pipeline diameters involved.

49 Aggregated TSO inventory of pipelines in accordance with the Federal Network Agency Monitoring Report 2015 minus apparent double counting by fractional ownership holdings (shared pipelines).

50 Dismantling: At the request of the property owner, the gas pipeline laid in the ground is removed and the land is returned to its original condition. Land registry entries for entitlements to the securing of lines are returned to property owners. Above-ground installations are dismantled.

51 Insulation and sealing: The natural gas line remains in the ground, and the pipeline is rendered inert and filled with fillers (e.g. betonite). The line cavity is closed off. Above-ground installations are dismantled.

52 Sealing: The natural gas pipelines are rendered inert and remain in the ground as cavities. Above-ground installations are dismantled.

Figure 45 Need for dismantling in DSO networks (without storage)

Inventory of plants		Proportion of dismantling measures [%]	Costs per unit [TEUR]/ [Km or unit]	Proportional demand for dismantling [%]
481,000 km[53]	Gas distribution network pipelines			
	Dismantling	5%	280	100
	Insulation and sealing	30%	200	
	Sealing	65%	20	
7,800	Large gas pressure-regulating stations		75	100
45,000	Small gas press-regulating stations		10	100
8 million	household connections			100

Source: FourManagement

According to this conservative estimate, the costs of dismantling distribution networks, which are taken into account when calculating the difference in costs between the scenarios, are EUR 20.1 billion (i.e. the lower limit of the above-mentioned cost range).

Since networks can only be decommissioned after all customers connected to these networks have undertaken conversion measures, it is assumed that network operators will first incur expenses for securing and dismantling lines as of 2035 onward.

According to our conservative cost estimate, the total costs for the decommissioning of gas networks amount to non-recurring costs of approx. EUR 3.1 billion for TSO networks and about EUR 20 billion for the DSO distribution networks respectively. Depending on the requirements of the property owners and communities (grantor of the concession), the costs may multiply if the entire network length significantly exceeds the conservative assumption of five per cent for dismantling.

D.2 Estimation of investment and maintenance costs

Based on expenses from 2015, estimates were made of the investment requirements and the expenses for maintaining and servicing the networks:

[53] Aggregated DSO inventory of pipelines in accordance with the Federal Network Agency Monitoring Report (2015).

Figure 46 Expenses for gas network operators in 2015 (in EUR million)

	Transmission network	Distribution network	Total
Investments in new construction and network expansion	341	682	1,023
Investments in retaining and restoring networks	155	431	586
Costs of maintenance and servicing	366	1,203	1,569
Total	**862**	**2,316**	**3,178**

Source: Monitoring report of the Federal Network Agency 2016 p. 276 ff

These 2015 estimates served as the basis for determining the investment requirements in 2050 for both scenarios:

Figure 47 Estimated expenses for gas network operators in 2050 (in EUR million) in the "Electricity and gas storage" scenario

	Transmission network	Distribution network	Total
Investments in new construction and network expansion	6	0	6
Investments in retaining and restoring networks	158	0	158
Costs of maintenance and servicing	183	120	303
Costs of dismantling and securing	**291**	**1,882**	**2,173**
Total	**638**	**2,002**	**2,640**

Source: FourManagement

We assume for the "Electricity and gas storage" scenario that investments in gas networks will significantly decrease. The expansion of the transmission gas networks only takes place at very select locations (e.g. connections to storage facilities and PtG plants). The total investment for new construction, expansion and retaining the networks shall only occur where a residual transport network remains necessary. Investments in new construction and expansion and in retraining distribution grids will be completely withdrawn.

For maintaining and servicing transmission networks, a reduction in costs of approx. 50 per cent can be expected due to a 2/3 reduction in the length of the network to be maintained. In the distribution network, the cost of managing and securing decommissioned distribution networks comprises 10 per cent of the 2015 maintenance costs.

Further costs arise in the networks due to the safe decommissioning and possibly necessary dismantling of the existing infrastructure. Based on the calculations provided in Annex D1, costs for the TSOs are estimated to be EUR 291 million per year and EUR 1.88 billion per year for DSOs between 2035 and 2050.

Overall, it is estimated that the 2050 costs of expanding, servicing, maintaining and dismantling the gas networks in the "Electricity and gas storage" scenario amount to EUR 2.64 billion per year as based on costs in 2015.

Figure 48 Estimated expenses for gas network operators in 2050 (in EUR million) in the "Electricity and green gas" scenario

	Transmission network	Distribution network	Total
Investments in new construction and network expansion	85	170	255
Investments in retaining and restoring networks	496	431	927
Costs of maintenance and servicing	366	1,203	1,569
Costs of dismantling and securing	**0**	**0**	**0**
Total	**947**	**1,804**	**2,751**

Source: FourManagement

The existing gas networks continue to operate in the "Electricity and green gas" scenario. In contrast to the reference year 2015, there is a shift in expenses from newly constructing and expanding the networks to maintaining and upgrading the networks. Investments, which were still required in 2015 to develop the networks, will be made on a comparable scale in the "Electricity and green gas" scenario to convert and modify networks to accommodate a higher content of hydrogen.

Since the expansion of distribution networks "from energy generation to final use" is no longer required due to the increased use of heat pumps supplying households, the total volume for investments and expenses decreases by approx. EUR 0.4 billion per year compared to 2015.

Figure 49 Comparison of the gas network costs for the different scenarios (for 2050)

(in EUR million per year)	"Electricity and gas storage" scenario	"Electricity and green gas" scenario	Difference in costs
Investments in the expansion and restoration of networks	163	1,182	-1,018
Costs of maintenance and servicing	303	1,568	-1,265
Costs of dismantling and securing	2,173	0	2,173
Total	**2,639**	**2,750**	**-111**

Source: FourManagement

In summary, the costs of the "Electricity and gas storage" scenario and the "Electricity and green gas" scenario are therefore almost the same.

ANNEX E DETAILS ON THE ANALYSIS OF COSTS IN THE PRODUCTION AREA

Beyond the remarks in **Section 4.2.4**, this Annex provides further details about how we determine the scenario-specific costs for producing and converting electricity.

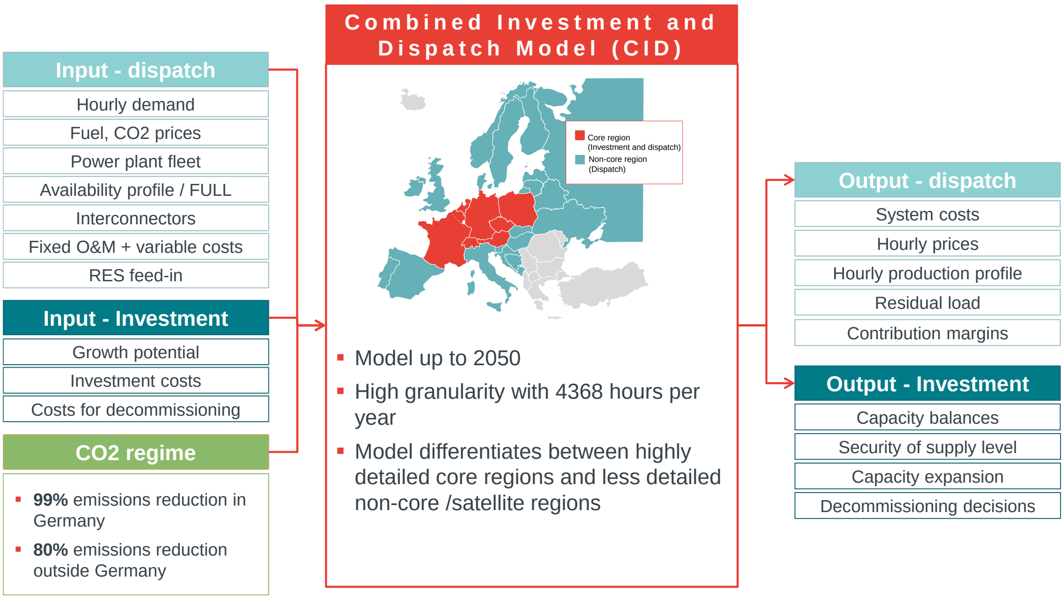
E.1 Model properties

To determine the costs, an established European electricity market model – which is described as follows – is used for reference.

- **Objective function** – The model minimises total costs of producing electricity in Europe (present cash value). The following items are key optimisation constraints:
  - coverage of the hourly energy balance in each region (with supply restrictions possible);
  - transmission network capacities between the regions; and
  - technical and economic constraints of power plants, storage, renewable energies and demand-side management (DSM).
- **Integrated investment and dispatch model** – The model is an integrated investment and dispatch model. The optimisation period is therefore based on the lifetime of power plants (the model optimises[54] up to 2050). The time resolution is up to 4,368 hours per base year. Based on the aggregated number of power plant units, this step is used to model the power plants to be added to and dismantled in the European fleet of power plants, whilst also taking into account, for example, capacity markets.
- The model is formulated as a **linear optimisation problem in GAMS**. Input and output data are using Microsoft Access and Excel. The optimisation problem is solved using the commercial solver CPLEX.
- One important model result are marginal costs of the system for 4,638 hours for the base years. The model can be used to generate information on the detailed operating modes of the power plants, requests for load flexibility and the exchange of electricity across model regions, etc. This information is used in this project to check plausibility and explain the model results.

[54] Basis years: 2015, 2020, 2030, 2040, 2050.

Figure 50 Overview of the model logic



Source: Frontier Economics

The model includes Germany and all neighbouring countries as well as other regions in Europe. The main model regions are the regions of DE, FR, BE, NL, LU, AT, SH, PL and CZ. (**Figure 50**):

- **Main model regions** (highlighted in red): Highly granular power plant fleet, optimised scheduling of power plants and optimised decisions concerning investments and decommissioning; and
- **Surrounding model regions** (highlighted in blue): Lower granularity of power plant fleet, exogenous development of capacities and optimised scheduling of power plants or exogenous hourly electricity prices and network capacities for the exchange of electricity within model regions.

E.2 Assumptions of the electricity market model

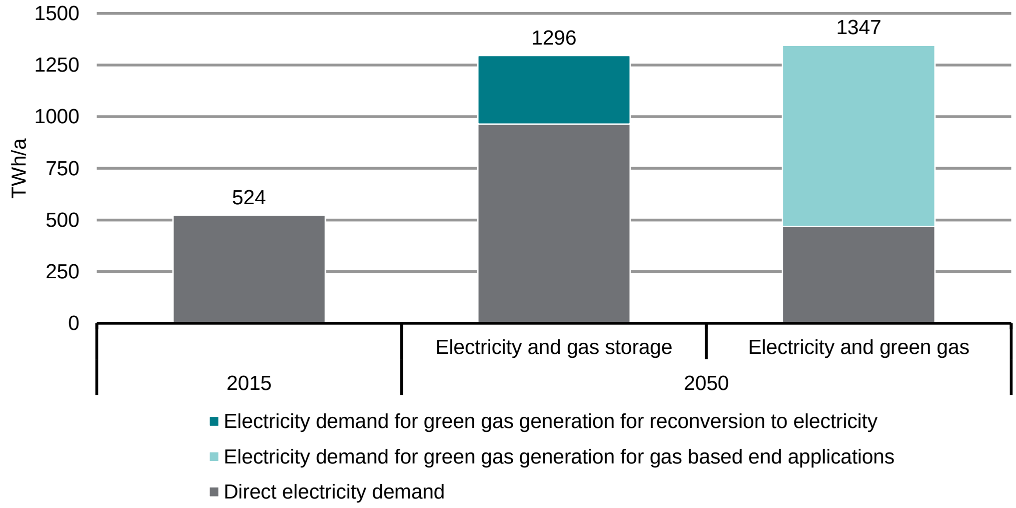
In this section we describe the main assumptions made for the electricity market model.

Demand for electricity and gas in Germany

The development of the demand for electricity in Germany up to 2050 was determined based on consumption for final energy applications in 2015 and their development until 2050. For 2050, this is taken directly from the scenario-specific final energy requirements (Cf. **Section 2.3** as well as **ANNEX A**), which, as input parameters, specify the electricity and gas requirements to be covered by the model.

The exogenous demand for electricity and gas in the model as well as the endogenous demand for gas (for reconversion) resulting from model pilot runs are shown in Figure 51.

Figure 51 Electricity demand in the scenarios



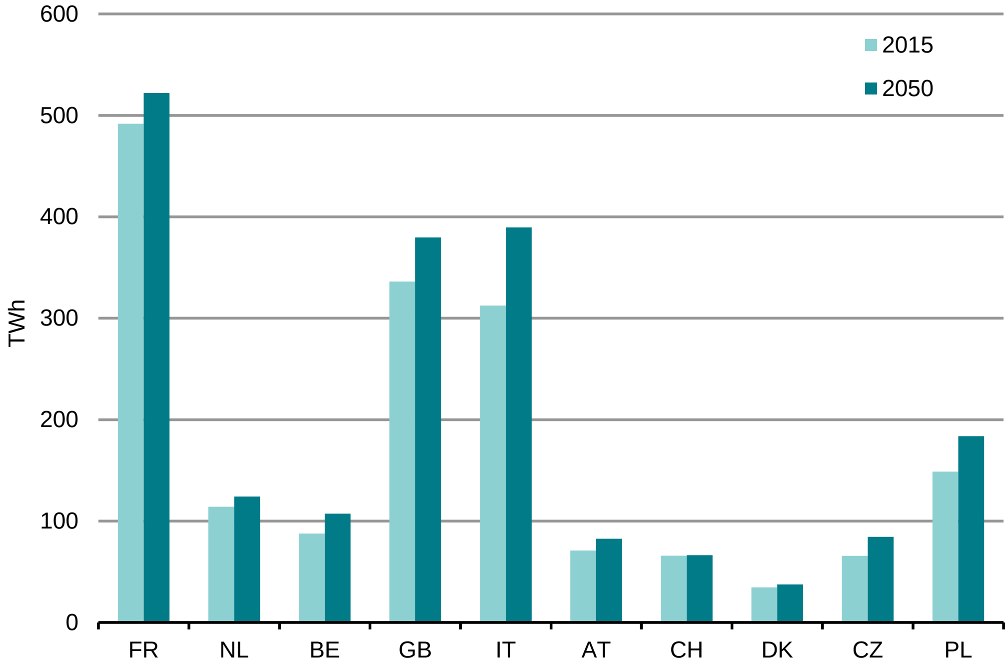
Source: Frontier Economics

Note: The total demand for electricity is taken from the direct demand for electricity as well as the demand from power-to-gas plants, which produce gas either directly for the final energy demand or for reconversion (the latter being already a model output).

Electricity demand in other model regions

The assumed development of the demand for electricity in the core region's other countries is shown in **Figure 52**. For the most part, the demand for electricity is expected to increase over the long run in these countries too. The detailed effects of sector coupling on the demand for electricity were not explicitly derived for these countries but common assumptions were selected for all scenarios to ensure maximum comparability.

Figure 52 Electricity demand in the core region (excl. Germany)



Source: Frontier Economics

Demand distribution over the course of the year for electricity and gas

For all scenarios, a demand profile over the course of the year is used as the input data for the electricity market model. An electricity consumption profile from 2012 is used as the basis here, since this year adequately represents the demanding weather conditions imposed on the supply of energy due to its dark periods with low wind supply starting from the end of January to mid-February as well as 21 days with an average temperature under 0 degrees Celsius. The electricity consumption profile from 2012 is adapted in several steps to reflect the progression of electricity demand over time in 2050 (cf. **Figure 12** on page 20):

- The assumption is made that there are no fundamental changes to the profile of the "original electricity consumption', or in other words the current consumption of electricity (e.g. for lighting). As a result, a "basic profile" which corresponds to the current load profile minus the assumptions made for increases in efficiency is derived. Consumption for new electricity applications is not included in this base profile.
- The basic profile is supplemented with the electricity consumption resulting from electrified industrial processes. We assume a uniform distribution over the course of the year for those.
- The electricity consumption profile from e-mobility is added according to a systematic load profile depending on the day of the week and the time of day.[55]

[55] Derived from the Forschungsstelle für Energiewirtschaft e.V. (2008), Probst (2014) und enercity (2015).

- The electricity consumption profile from heat applications is compiled based on a temperature-dependent synthetic load profile and also added to the electricity load profile.[56]

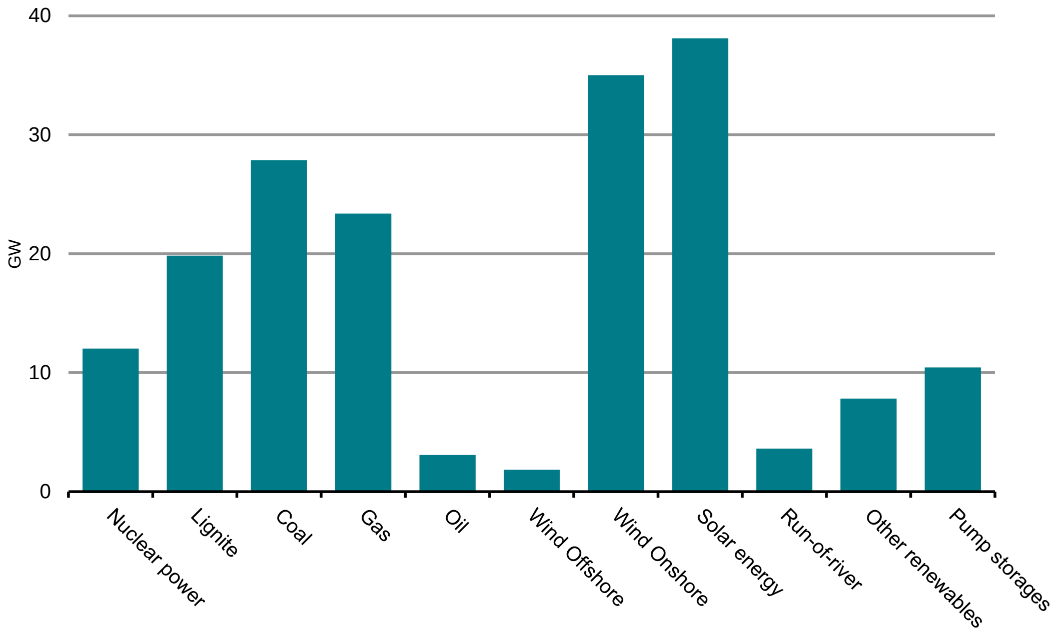
Since the use of demand-side flexibilities (e.g. heat pumps, electric vehicles) and energy storage (e.g. pumped storage, batteries) are determined endogenously by the model, their effects on the electricity demand in the exogenous profiles are not yet shown.

End consumer's consumption of gas only occurs in the "Electricity and green gas" scenario. It is assumed that existing gas storage volumes (same as the current situation) will suffice to offset seasonal fluctuations of gas consumption in future. A dedicated gas consumption profile is therefore not generated.

Conventional power station capacities

The German fleet of power plants is incorporated in the electricity market model on an individual power plant basis. The reference year capacities are based on the BNetzA power plant list. **Figure 53** shows the capacities per fuel type. The power plant capacities of the other countries in the model are based on ENTSO-E and Platts Powervision statistics. As an integrated dispatch and investment model, investment and decommissioning decisions are made endogenously in the model. Known constructions and decommissionings as well as target corridors (e.g. EEG 2017) are taken into account exogenously. Carbon capture and storage (CCS) is politically difficult to achieve in Germany and is thus not considered as an additional capacity option. The power plant capacities in all of the core region's countries in 2015 are depicted in Figure 54.

Figure 53 Power plant capacities in Germany in 2015



Source: Frontier Economics based on data from the Federal Network Agency list of power plants

[56] Cf. KommEnergie (2017).

Figure 54 Power plant capacities in the model region in GW (excl. DE), 2015.

	FR	NL	BE	GB	IT	AT	CH	DK	CZ	PL
Kernenergie	63,1	0,5	3,8	9,6	0,0	0,0	3,2	0,0	4,0	0,0
Braunkohle	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	8,1	9,4
Steinkohle	4,7	6,3	0,5	19,2	5,2	1,2	0,0	1,3	1,9	19,1
Gas	6,4	10,1	5,9	31,4	41,6	2,8	0,1	2,3	1,5	1,3
Öl	6,8	0,7	0,8	1,0	6,6	0,4	0,0	0,7	0,0	0,3
Wind Offshore	0,0	0,4	0,7	6,1	0,0	0,0	0,0	1,3	0,0	0,0
Wind Onshore	8,6	2,7	1,1	8,9	8,6	2,1	0,1	3,7	0,3	3,8
PV	5,2	1,6	2,9	4,8	18,2	0,7	0,5	0,6	2,1	0,0
ROR	10,3	0,0	0,1	1,1	10,4	5,6	3,8	0,0	0,2	1,0
KWK	0,0	6,9	0,0	0,0	0,0	1,8	0,0	0,0	0,2	0,0
Andere EE	1,1	0,8	0,5	3,8	3,1	0,7	0,0	1,5	0,3	0,4
Hydro	13,2	0,0	1,3	2,7	13,0	7,3	9,3	0,0	1,9	1,4

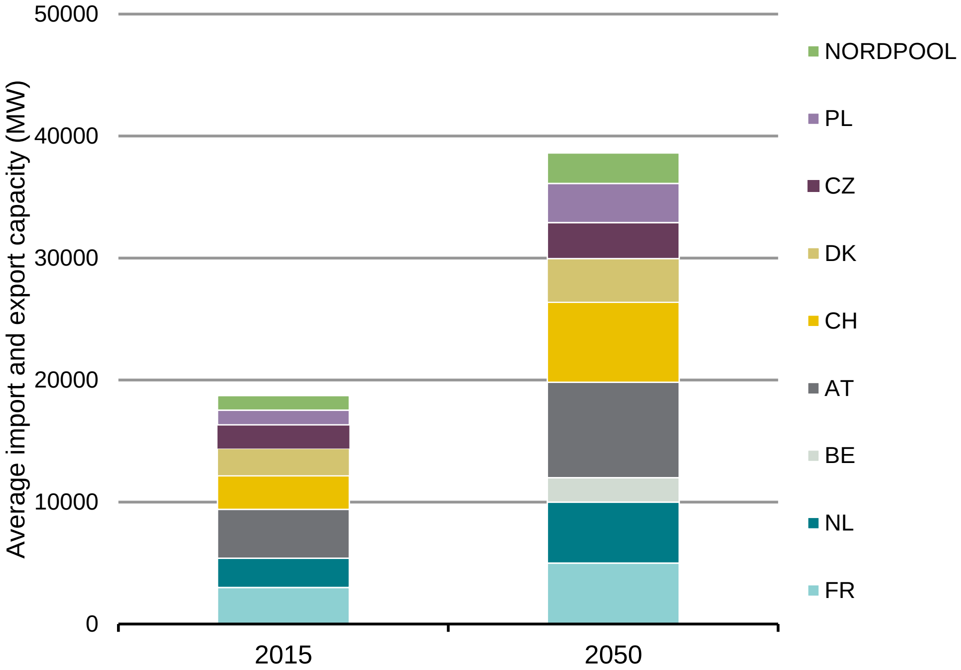
Source: Frontier Economics based on the Federal Network Agency, Platts Powervision and ENTSO-E

Expansion of interconnector capacities

The expansion of the international transmission network uses a model based on ENTSO-E's 2014 Ten-Year Network Development Plan ("TYNDP").[57] According to the TYNDP, trade capacities between Germany and the neighbouring countries will double by 2050 (cf. **Figure 55**). The interconnector capacities of the core region also show that they will double by 2050 and are depicted in **Figure 56**.

[57] Changes in TYNDP 2016 and in the network development plan 2016 are taken into account here.

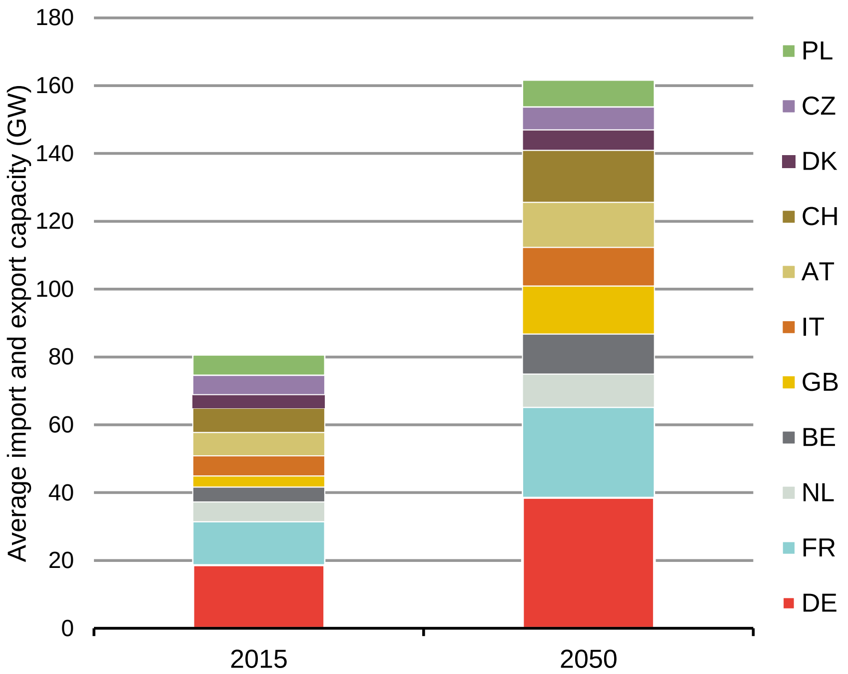
Figure 55 German interconnector capacity



Source: ENTSO-E (2014/2016): TYNDP Scenario Development Report.. Federal Network Agency (2016): Approval of the scenario framework for network development plans for electricity 2017-2030

Note: Modified assumptions for TYNDP data: Five-year delay assumed for projects in the "Design and Permitting" phase/not considered in the status "Under consideration".

Figure 56 Interconnector capacities for the entire core region



Source: ENTSO-E (2014/2016): TYNDP Scenario Development Report.. Federal Network Agency (2016): Approval of the scenario framework for network development plans for electricity 2017-2030

Note: Modified assumptions for TYNDP data: Five-year delay assumed for projects in the "Design and Permitting" phase/not considered in the status "Under consideration".

Power-to-gas plants

Depending on the scenario, the model can endogenously make decisions about the construction and deployment of power-to-gas plants and about the use of synthetic gas produced for this purpose – if necessary by way of temporary storage – for reconversion or to satisfy gas demand (in the "Electricity and green gas" scenario).

The "Electricity and green gas" scenario also raises the question of whether hydrogen shall be used directly or whether methanisation shall serve as an intermediate step. Here, it can be assumed that ultimately a mix of technologies will be used. Due to the rapid pace of technological advancements in this field, we assume for simplicity that 50 per cent of the green gas is directly transported and used as hydrogen (PtH2; in the transport and industry sectors), while the other 50 per cent of the green gas is additionally methanised (PtCH4) and transported in particular via transmission and distribution networks to the heat consumers.

Figure 57 below summarises the main assumptions made about the conversion processes:

The following parameters were assumed for electrolysis in 2050 (all EUR-values expressed in real 2015 terms):

- Investment cost of 250 EUR/kWel;
- Operating costs of 2% of the investment costs per year;
- Efficiency rate of 80%.

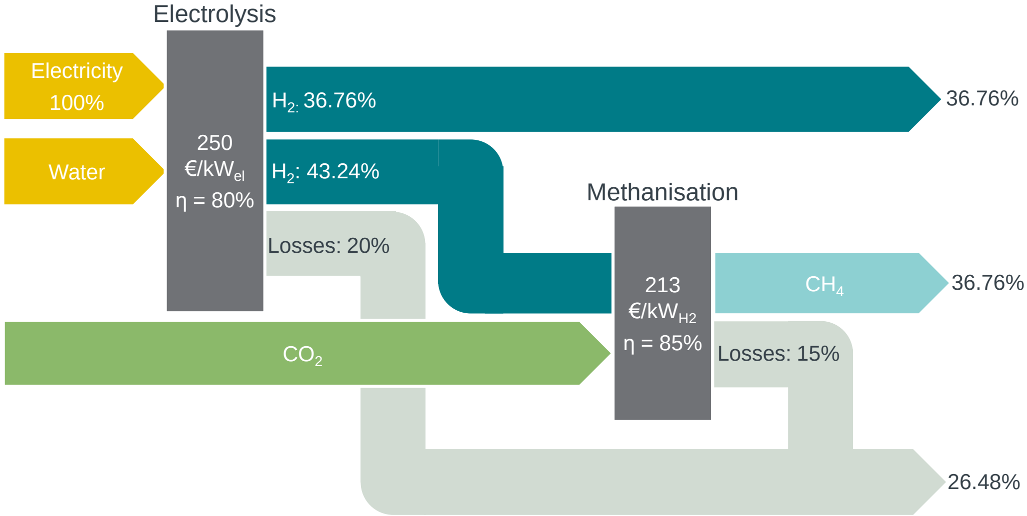
The following parameters were assumed for the process step of the methanisation:

- Investment cost of 213 EUR/kWel;
- Operating costs of 1% of the investment costs per year;
- Costs for CO_2 of 50 EUR/t CO_2;
- Efficiency rate of 85%.

Both the costs as well as the efficiency rates of electrolysis and methanisation reflect the expected state of the art by 2050. **Figure 58** compares different investment cost estimates for electrolysis in 2050, which range between EUR 200/kWel and 724/kWel. Because we consider large power-to-gas plants (in the range of several 100 MWs each) and a broad penetration of those (total capacity of more than 100 GW), we assume that investment costs will amount to EUR 250/kWel, i.e. at the lower end of the interval of estimated costs.

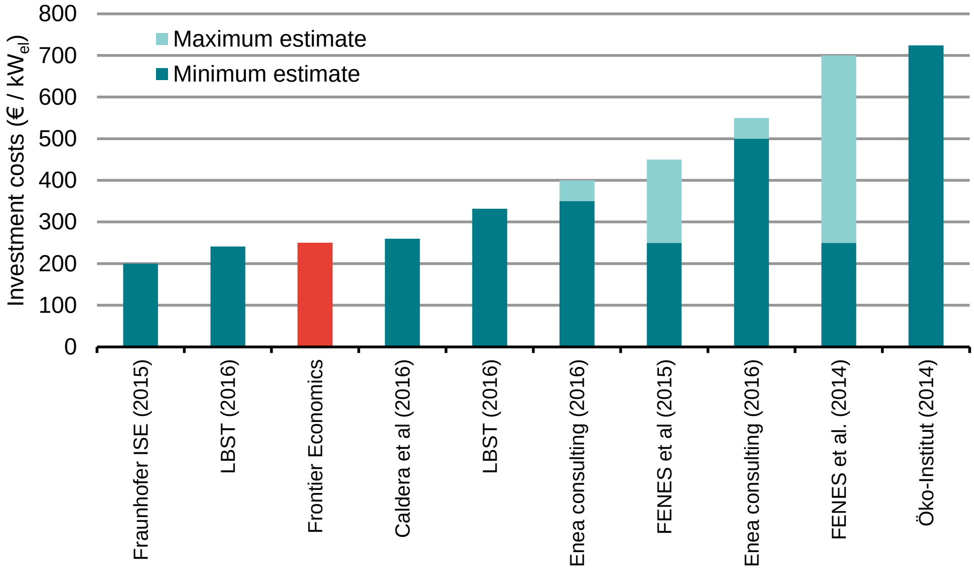
As a carbon source for the process of methanisation, it is assumed that carbons can be obtained from biogas and biomass power generation as well as from unavoidable CO_2 emissions from industrial processes. In the case of reconversion, CO_2 can also be captured here and then made available again for methanisation. Overall, based on the potential of all the domestic sources of CO_2 still remaining in 2050, we believe that the expensive process of direct air capturing of CO_2 is not required. The cost of supplying CO_2 is estimated at EUR 50 per tonne.

Figure 57 Main assumptions made for the parameterisation of power-to-gas plants for an even split of CH4 and H2



Source: Frontier Economics

Figure 58 Investment cost estimates for an electrolyser in 2050



Source: Frontier Economics based on Fraunhofer (2015b), LBST (2016), Caldera et al. (2016), Enea consulting (2016), FENES et al (2015), Enea consulting (2016), FENES et al. (2014) and Öko Institut (2014).

E.3 Results of electricity market model

We present a comparison of detailed results of the electricity market model for the two scenarios in the following:

Generation of electricity and capacities

The following figures show the respective capacities and production quantities resulting in the "Electricity and gas storage" and "Electricity and green gas" scenarios:

In conclusion, we see that both scenarios are characterised by a strong expansion of renewable capacities as compared to 2015. This development is the result of an increase in direct and indirect (via PtG) demand for electricity and the simultaneous non-use of fossil fuels (complete decarbonisation of electricity production).

The demand for electricity in 2050 increases from 524 TWh in 2015 to:

- 1,296 TWh in the "Electricity and gas storage" scenario; and to
- 1,350 TWh in the "Electricity and green gas" scenario.

Electricity demand comprises the end consumers' demand for electricity, the electricity required to produce synthetic gas and conversion losses from storage. Due to this increase in electricity demand, the installed capacity of renewable energy will increase from 86 GW in 2015 to:

- 581 GW in 2050 in the "Electricity and gas storage" scenario; and
- 624 GW in 2050 in the "Electricity and gas storage" scenario respectively.

In addition to the aforementioned renewable energy capacities, the "Electricity and gas storage" scenario requires 108 GW of gas power plants to reconvert stored synthetic gas (e.g. to protect against dark periods with low wind). This purpose is also reflected in the full load hours of the gas power plants: With 1,300 operating hours per year, they have a capacity utilisation of only approximately 15 per cent.

Overall, this means that more generating capacity is installed in the "Electricity and gas storage" scenario than is in the "Electricity and green gas" scenario.

Figure 59 Available power plant capacity in 2015 and 2050 (GW)

	2015	2050	
		Electricity and gas storage	Green electricity and green gas
Nuclear energy	12.03	0.00	0.00
Lignite	19.83	0.00	0.00
Black coal	27.87	0.00	0.00
Gas	23.37	108.00	10.00
Oil	3.08	0.00	0.00
Off-shore wind	1.85	169.78	193.13
On-shore wind	35.00	195.56	190.87
Solar energy	38.10	193.22	217.87
Run-of-the-river hydroelectricity	3.62	4.55	4.55
Other RES	7.83	17.58	17.58
Pumped hydro storage	10.44	18.20	10.70
Other storage	0.00	14.00	0.00
Total	**183.02**	**720.89**	**644.70**

Source: Frontier Economics

Figure 60 Electricity generated in 2015 and 2050 (TWh)

	2015	2050	
		Electricity and gas storage	Green electricity and green gas
Nuclear energy	85.92	0.00	0.00
Lignite	142.99	0.00	0.00
Black coal	109.10	0.00	0.00
Gas	53.37	141.06	10.41
Oil	0.00	0.00	0.00
Off-shore wind	7.00	642.73	731.10
On-shore wind	66.70	372.67	363.74
Solar energy	33.81	171.49	193.37
Run-of-the-river hydroelectricity	17.33	21.83	21.83
Other RES	38.66	101.57	107.66
Pumped hydro storage	10.14	27.09	14.05
Other storage	0.00	21.18	0.00
Net demand	529.42	1,345.15	1,357.00
Net imports	-35.60	-152.56	-83.77

Source: Frontier Economics

Note: The quantities produced from gas for 2050 refers exclusively to green gas used for reconversion.

Power-to-gas

The construction and deployment of power-to-gas plants is determined endogenously in the model. While gas production is not specified in the "Electricity and gas storage" scenario, the model in the "Electricity and green gas" scenario stipulates a minimum gas production requirement to operate the gas-based end-user applications assumed in this scenario.

In conclusion, the "Electricity and gas storage" scenario shows power-to-gas plants built with a capacity of 134 GWel, which generate 244 TWh of green gas year-round. This is equal to 2,471 full load hours. The gas produced is used completely for reconversion in this scenario. The "Electricity and green gas" scenario shows power-to-gas plants built with a capacity of 254 GWel, by 2050. These plants produce 646 TWh of green gas year-round, which is equal to 3,457 full load hours. From this production, 645 TWh are used for end-user applications and 1 TWh is used for reconversion.

Figure 61 Use of power-to-gas plants

Scenario	Installed capacity of electrolysers	Gas produced	Hours at full load
Electricity and gas storage	134 GWel	244 TWh	2,471 h
Electricity and green gas	254 GWel	646 TWh	3,457 h

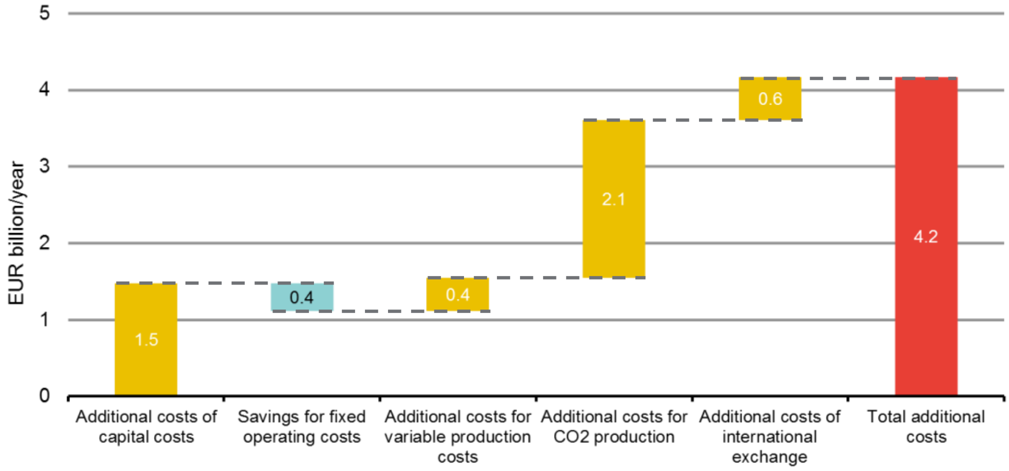
Source: Frontier Economics

In the "Electricity and green gas" scenario, there is a higher production of synthetic gas because of the specified minimum production requirements for gas-based end-user applications. The power-to-gas plants provide the system with considerable flexibility potential, meaning that when there is a lower availability of electricity, synthetic gas need not be produced, which temporarily reduces electricity load. The system can virtually operate autonomously, without any additional gas power plants.

System costs

Overall, the "Electricity and gas storage" scenario shows lower system costs for producing and converting electricity as with the "Electricity and green gas" scenario. This is mainly due to the additional capacities for renewable energies and power-to-gas plants, as well as the costs associated with operating the power-to-gas plants, particularly the cost of providing CO_2 for methanisation. **Figure 62** compares the system cost differences arising between the two scenarios.

Figure 62 Comparison of the system costs between the "Electricity and gas storage" scenario and the "Electricity and green gas" scenario in 2050



Source: Frontier Economics

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