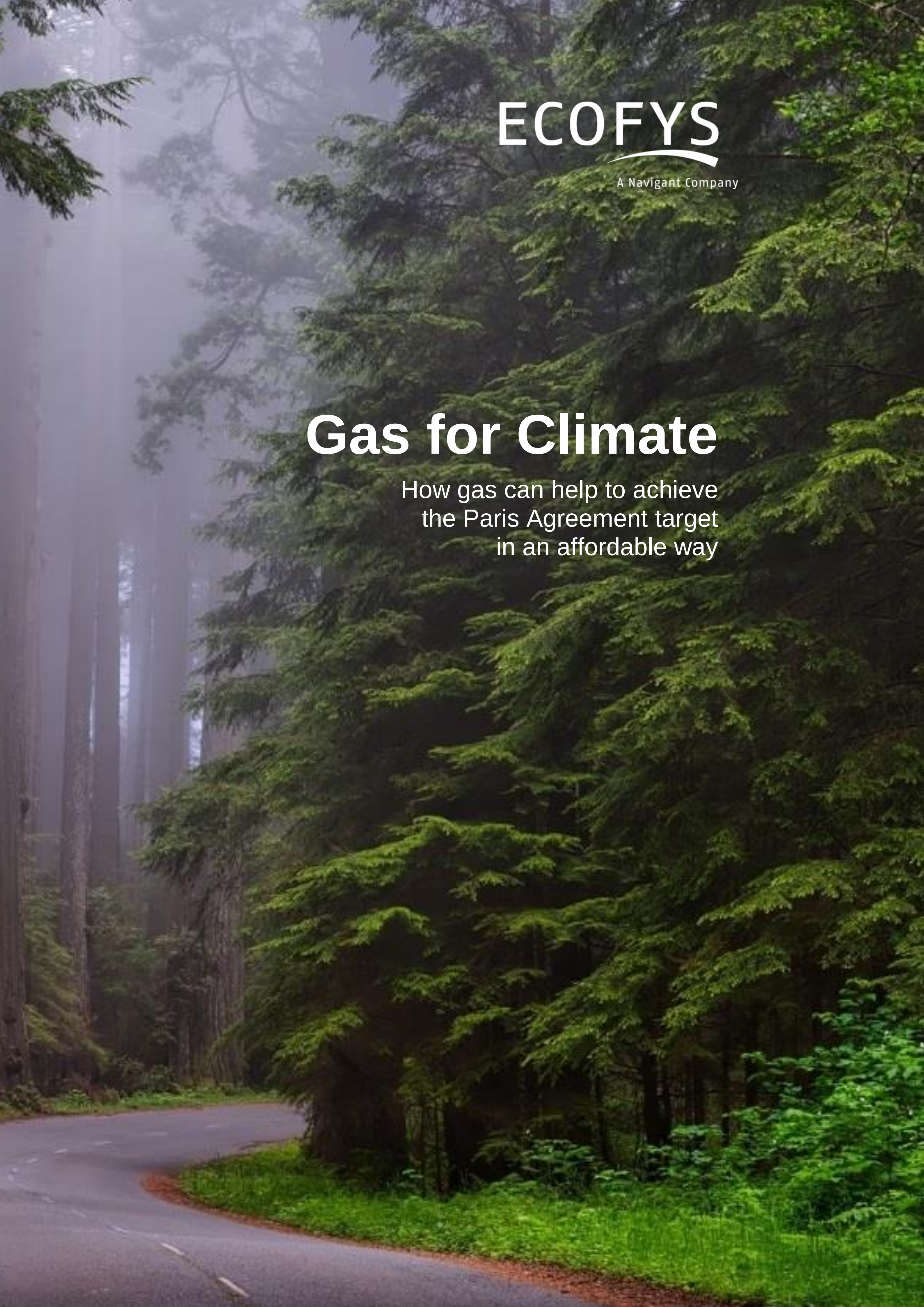

ECOFYS
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Gas for Climate

How gas can help to achieve
the Paris Agreement target
in an affordable way

Gas for Climate

How gas can help to achieve the Paris Agreement target in an affordable way

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Executive Summary

To achieve the Paris Agreement target of limiting global temperature increase to well below two degrees, a major redesign of the energy system is required. This study by Ecofys, a Navigant company, explores the role of gas in a fully decarbonised energy system by 2050. We conclude that it is possible by 2050 to scale up renewable gas (biomethane and renewable hydrogen) production in the EU to a quantity of 122 billion cubic metres by 2050. We also conclude that using this gas with existing gas infrastructure, smartly combined with renewable electricity in sectors where it adds most value, can lead to €138 billion societal cost savings annually compared to decarbonisation without a role for renewable gas.

This study has been commissioned by Gas for Climate, a consortium of seven gas transport companies (Enagás, Fluxys, Gasunie, GRTgaz, Open Grid Europe, Snam and TIGF) based in six EU Member States plus two renewable gas producing organisations (European Biogas Association and Consorzio Italiano Biogas). The group shares the vision that renewable and low carbon gas, transported, stored and distributed by the existing gas infrastructure, can help to achieve a net zero carbon European energy system by 2050 in a cost-effective way.

"Use of renewable gas can save €138 billion per year by 2050."

This study starts from the perspective that all gas consumption in Europe must, by 2050, be net zero carbon. This means that it is produced from renewable sources and that any remaining natural gas consumption will be combined with carbon capture and storage or capture and permanent utilisation[1]. Ecofys analyses how much renewable gas Europe can produce and what the societal value is of using this gas in existing gas infrastructure in various sectors of the economy. Based on conservative assumptions, we conclude that it is possible to greatly increase the production and use of renewable gas in the EU. Keeping the existing gas infrastructure in place to enable the transport, storage and distribution of this renewable gas significantly lowers the total EU energy system costs.

Gas can play a significant role in a fully decarbonised energy system. This is possible through the large-scale implementation of sustainable biomethane production produced from a range of agricultural and woody biomass types. A prudent estimation of a truly sustainable production potential of biomethane within the EU shows that it is possible to produce at least 98 billion cubic metres (bcm), i.e. 1,072 TWh of energy annually by 2050. By focusing on EU production, the security of Europe's energy supply will improve and the rural economy will be strengthened. In addition, we see the potential to produce 24 bcm of renewable hydrogen by converting low cost wind and solar electricity into hydrogen.

[1] For CCU to qualify as a decarbonisation measure, the products that are produced with CO_2 must have a sufficiently long lifecycle. Ideally the carbon is never released back to the atmosphere, but also with very long lifecycles (decades) and a cycle of CO_2 use and release, significant amounts of CO_2 can be kept out of the atmosphere.

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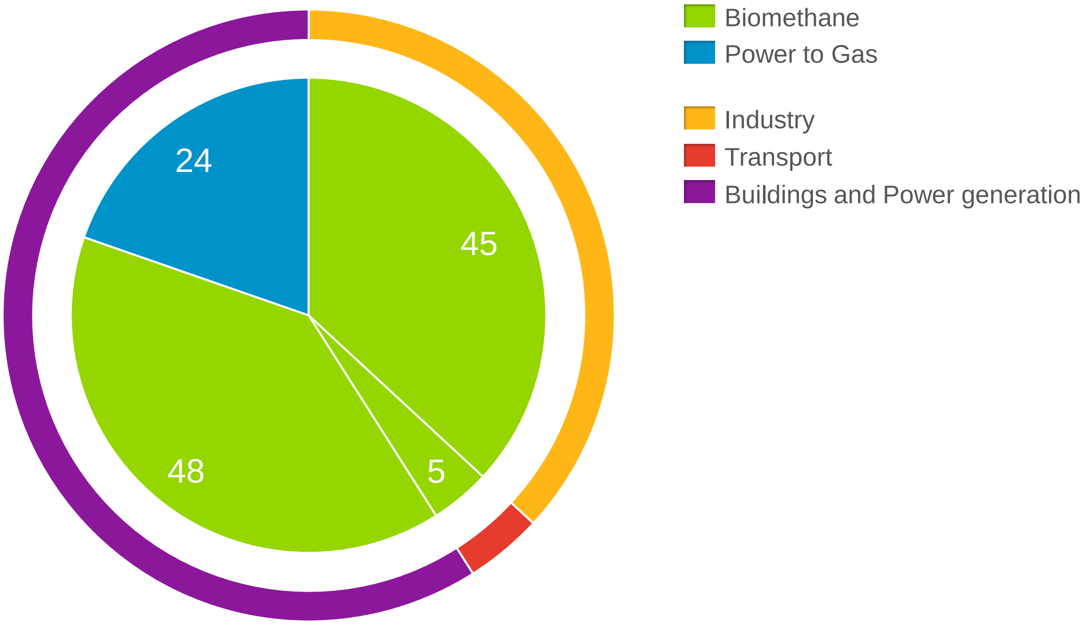
This leads to a combined renewable gas potential of 122 bcm of renewable gas per year. Imports may further increase this renewable gas potential. For example, Ukraine and Belarus could supply an additional 20 bcm of biomethane annually.

The 122 billion cubic metres of EU produced renewable gas is allocated over those economic sectors where we anticipate the highest societal cost savings, which are the heating of buildings and electricity generation. We also allocate a quantity of gas to heavy duty transport. In addition, we allocate a quantity of 45 bcm renewable gas to industry that should, according to the IEA B2DS scenario, be sufficient to decarbonise that sector by 2050, although the cost savings from using gas in industry are not modelled in this study. The figure below shows this allocation of gas over various sectors.

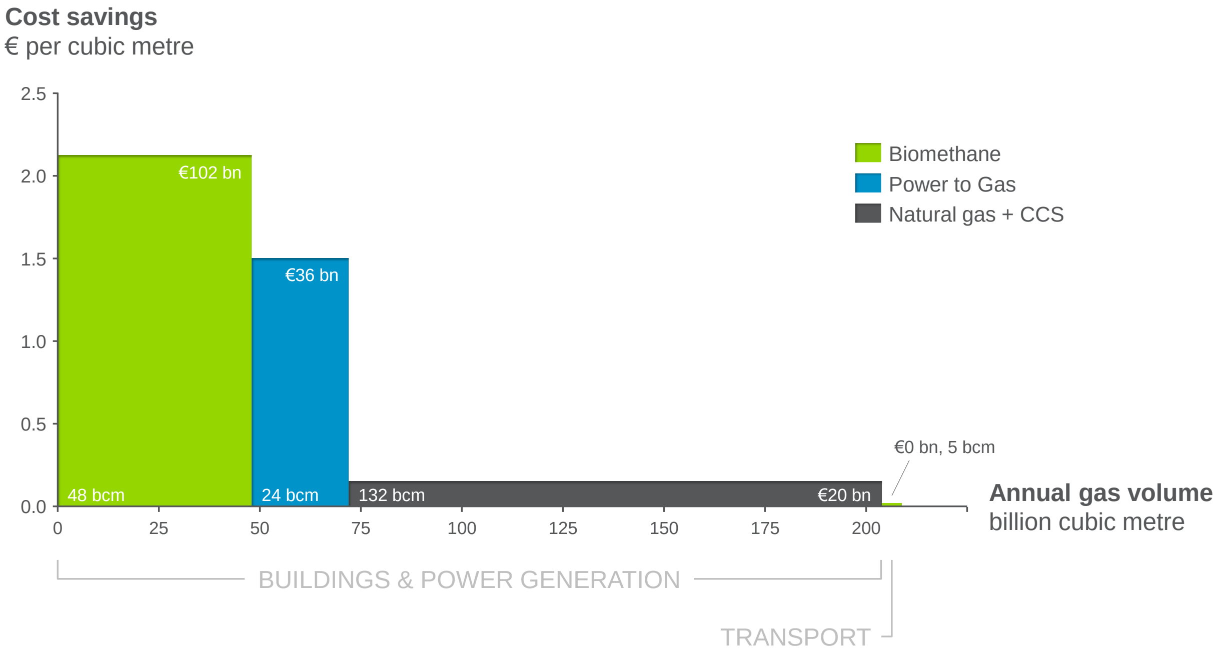


Allocation of renewable gas over various sectors in billion cubic metres of gas

Not taking into account renewable gas allocated to industry, Ecofys modelled the societal cost savings that can be achieved by using just 77 out of the 122 bcm of renewable methane and hydrogen in existing gas infrastructure to heat buildings, produce electricity and fuel heavy transport. Of this, 5 bcm allocated to transport is cost-neutral compared to biofuel, while providing a sustainable and scalable alternative to decarbonise heavy transport. The remaining 72 bcm of renewable gas used in buildings and electricity generation and leads to societal cost savings of €138 billion per year by 2050 compared to a decarbonised energy system without any role for renewable gas. These cost saving is equivalent to about €600 per EU household per year. They are achieved mainly by avoiding the costs associated with building and running the necessary generation capacity to meet high peaks in electricity demand, as well as through substantial savings on insulation costs for buildings to accommodate full-electric heat pumps.

The figure below shows the annual societal cost savings in the energy system from the use of renewable gas. The study does not estimate a certain consumption level of natural gas with CCS, given high uncertainties related to technical availability (long distance transport and storage within the EU) and societal acceptance.

The estimation of cost savings associated with a quantity of 132 bcm of natural gas with CCS is included (based on the IEA B2DS scenario extrapolated to 2050) as an illustration that also the use of low carbon gas leads to societal cost savings compared to an energy system without any gas.



Annual quantities of renewable and low carbon gas and associated societal cost savings associated with using this gas in the EU energy system by 2050

Sometimes it is argued that to meet the Paris Agreement climate change target, Europe should abandon the gas grid, stop the use of gas and focus on an all-electric energy system. Besides the notion that it will be challenging to implement this (e.g. in specific industrial processes), our analysis shows that the optimal energy transition combines renewable electricity with renewable gas, using existing gas infrastructure. Assuming further growth of renewable electricity and electrification of energy demand, we demonstrate that the right combination of electricity and gas is more cost-efficient while bringing additional societal benefits (e.g. improved security of supply, stronger rural economy), and is therefore closer to the socio-economic optimum. The energy transition remains an enormous challenge, and it is uncertain which combination of existing and future technologies will provide our energy services in 2050. Therefore, we should not exclude upfront any technology from playing a long-term role, and especially not existing gas infrastructure that has been paid for and is capable of transporting large volumes of energy efficiently over long distances. Europe does not have to stop investing in gas infrastructure but it must be ensured that these investments fit the long-term role of gas in the energy transition.

We recommend to further explore how the vision as described in this report can be achieved in practice by identifying the steps that are required from the gas sector, from policy makers and other stakeholders today and tomorrow to scale-up renewable gas production and to ensure its best use in our energy system.

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1 Introduction

In the Paris Agreement, 195 countries have agreed to keep global warming well below 2°C above pre-industrial levels. This requires strong greenhouse gas emission reductions, especially from the developed, generally high-emitting, countries. The European Union has committed to reduce its emissions by 80 to 95% by 2050 compared to 1990 levels. This target was set prior to the Paris Agreement and it seems likely that the target will move towards the upper end of this range. This requires a transition towards a zero-carbon energy system.

There is consensus that achieving a zero-carbon energy system will only be possible with forceful efforts to increase energy efficiency in all sectors including buildings, industry and transport, combined with a rapid scale-up of renewable energy and low carbon technologies. In addition, Europe's energy supply should also remain reliable, secure and competitive, which are crucial elements to ensure public acceptance of the energy transition. The threefold aim of sustainable, secure and competitive energy forms the core of Europe's energy policy.

"There will be a growing need for flexibility in the electricity system."

Europe has made important steps towards a more sustainable, secure yet still competitive energy supply. The share of renewable energy has greatly increased in recent years, mainly renewable electricity from wind and solar, driven partly by EU regulation centred around the Renewable Energy Directive. This large-scale implementation caused renewable electricity technologies to further mature, resulting in cost reductions. The costs of wind and solar have dropped by an impressive 40%[2] (onshore wind) to 80%[3] (solar PV) during the last 10 years. At the same time, the role of coal as a very carbon intense energy source slowly starts to dwindle, with coal gradually being replaced by renewables and natural gas, with a lower carbon intensity.

Renewable electricity provided 30% of the total EU electricity supply in 2016, which equals 17% of total gross final energy consumption in the EU[4]. With increasing levels of wind and solar power and increasing demand for electricity for heat pumps and electric vehicles, there will be a growing need for flexibility in the electricity system. The electricity system is designed in such way that supply and demand are in constant balance, without much possibility to store energy in the electricity network. Constantly changing electricity demand following changing weather conditions and differences in demand between day and night and between summer and winter needs to be met. Today, this function is performed by coal, oil and gas, all of which can be stored in large quantities at low prices. All provide flexibility in the energy system. The large additional benefit of natural gas is that it has a much lower greenhouse gas intensity compared to oil (-23%) and coal (-41%)[5].

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[2] IRENA, 2016: The Power to Change
[3] Agora, 2015: Current and future cost of Photovoltaics
[4] http://ec.europa.eu/eurostat/statistics-explained/index.php/Renewable_energy_statistics
[5] IPCC, 2006: IPCC Guidelines for National Greenhouse Gas Inventories.

Also, the combustion of natural gas reduces air pollution (e.g. NO_x, SO_x, small particles) compared to coal and oil. In addition to being used to produce electricity, natural gas is used to provide energy for industry, for space heating of buildings and also in mobility.

For the long-term however, there is a challenge. On the one hand, gas is a suitable companion of renewable electricity, allowing back-up and storage and increasing the affordability and security of supply. On the other hand, the emissions that are inherently related to the use of natural gas need to be reduced. All energy sources must be decarbonised to achieve the Paris Agreement target on climate change. This means that all gas that is consumed in the EU needs to be zero-carbon or net zero carbon, meaning that any remaining emissions have to be compensated by negative emissions. Sometimes it is argued that natural gas should be fully phased out and replaced by renewable electricity production.

Against this background, a group of European gas transmission system operators (TSOs) and biogas producing organisations came together in June 2017 to explore the future of gas and gas infrastructure in a decarbonised EU energy system by 2050. This became the Gas for Climate group. Gas for Climate fully supports the Paris Agreement target on climate change and the resulting need for deep decarbonisation, including in the EU. Gas for Climate asked consultancy firm Ecofys, a Navigant company, to analyse the future role of gas and gas infrastructure in the light of 'Paris'.

1.1 Aim and scope of this study

In this report, Ecofys analyses to what extent gas used in existing gas infrastructure can help to achieve the 'Paris' target to limit global temperature increase to well below two degrees Celsius. We assess to what extent renewable gas (defined in this report as hydrogen and methane produced from renewable electricity as well as biomethane) can be scaled up. We subsequently assess how renewable gas and low carbon gas (defined as natural gas combined with CCS or permanent CCU[6]) can be used in three sectors, namely the heating of residential and commercial buildings, electricity production and heavy duty transport.

We assess the societal cost saving of using gas in these sectors compared to a decarbonised energy system *without* the use of gas. We assume that renewable and low carbon gas will make use of existing gas transmission and distribution infrastructure.

[6] CCS stands for 'carbon capture and storage'. CCU means 'carbon capture and utilization'. In this report we include only CCU that leads to negative emissions through (semi) permanent CO_2 storage, for example by producing cement or through carbonation. The potential for such (semi) permanent storage through CCU is not expected to be very significant. CCU in the broader sense can have the benefit that it will generally have a better business case compared to CCS, because the CO_2 is being used by another industry and thus can reduce capturing costs during coming decades and thereby mature to play a role in decarbonisation. Due to the expected limited potential for CCU we expect that by 2050 CCS will have more potential to abate remaining natural gas emissions.

We chose to analyse the role of gas to heat buildings, produce electricity and fuel heavy duty transport for the following reasons. The residential and commercial building sector was chosen because it is possible to heat buildings fully with electricity and the role gas can play in the decarbonisation of this sector is not well understood. The electricity sector was chosen because an energy system with higher shares of wind and solar PV requires sufficient storage and balancing capabilities. Often battery storage is considered to be the most optimal solution, while electricity from renewable gas combined with gas storage can complement wind and solar PV to decarbonise the energy system, specifically at times of high demand, also called 'peak electricity'. The heavy transport sector (trucks and ships) was chosen because there is currently little use of gas in transport, while there is an opportunity to use biomethane to decarbonise this sector as an alternative or complement to liquid biofuels. The use of gas to produce industrial process heat is relatively widely recognised and therefore not included in our cost assessment. Because industrial heat also needs to be decarbonised, we 'reserve' a significant share of renewable gas to be used in industry.

"An energy system with higher shares of wind and solar PV requires sufficient storage and balancing capabilities."

The three sectors we assess in this report jointly consume a share of 57% of total final energy consumption in the EU today. The sectors are responsible for 42% of total EU greenhouse gas emissions.

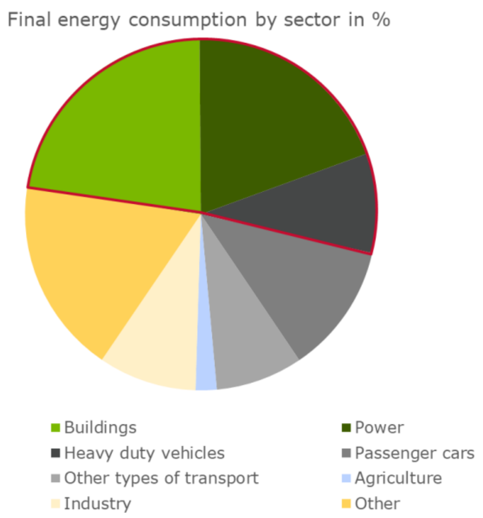

Figure 1 Current final EU energy demand per sector and share covered by our analysis

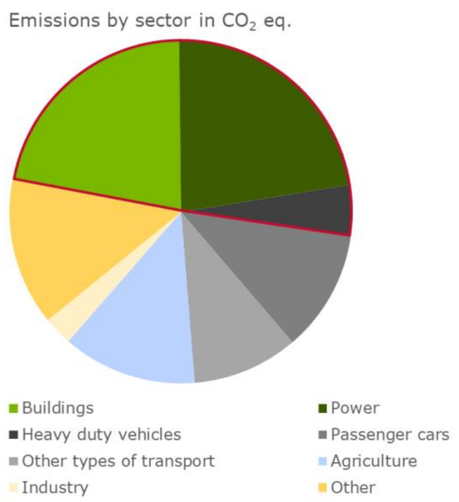

Figure 2 Current emissions per sector and share covered by our analysis

Our analysis starts from the perspective that the use of electricity in the EU energy system will increase. The European Energy Roadmap 2050 foresees that the share of electricity in final energy consumption will increase from about 22% today to 35-40% in 2050. Yet at the same time full electrification of the total energy system is very challenging. For example, many (chemical) processes in industry will continue to require combustible energy carriers. We explore in this study how much societal cost saving can be created by smartly combining renewable electricity with renewable and low carbon gas. Our starting hypothesis is that combining electricity with gas can speed up the decarbonisation of the energy system and allow Europe to achieve the Paris Agreement target at the lowest possible cost.

“Combining electricity with gas can allow Europe to achieve the Paris Agreement target at the lowest possible cost.”

1.2 Reading guide

This report starts by setting the scope of the performed study. Chapter 2 sets out the differences and similarities between the current gas and electricity systems. Next, Chapter 3 describes the sources of our renewable or low carbon gas including the related sustainability criteria. Chapter 4 then elaborates on how such an increased supply of renewable and low carbon gas can be used to create value in the future EU energy system. The main conclusions of the study are included in the Executive Summary above. This report presents the key findings, while additional details on our methodology and results are included in a separate Annex.

2 Complementarity of gas and electricity

Gas and electricity share certain important characteristics. Both are predominantly grid bound, historically have centralised production facilities and have regulated, finely mazed networks that connect many consumers and companies.

At the same time however, differences exist that have determined their development in the past and will determine their optimal deployment in the future. As this study aims to find an optimal deployment of gas and electricity, it is fitting to start with a summary of the differences and similarities in terms of production, storage, transport and distribution and use, and how these differences impact the costs of decarbonisation efforts.

Production

The production of (renewable) electricity can take place at low cost. The marginal cost of a unit of electricity from natural gas is about €40 per MWh today[7]. Solar PV is below grid parity in many countries, and starting to reach competitive wholesale prices. Required subsidies for onshore and offshore wind have dropped significantly in the past years. Whilst wind and solar resources are near inexhaustible, local resistance to onshore wind and centralised solar can be substantial.

Natural gas currently trades around €20 per MWh on the wholesale market currently. Renewable gas production is still more expensive, with costs of around €100 per MWh today to produce biomethane.[24] Renewable hydrogen is not yet produced or used at commercial scale because it is currently too expensive[8]. In addition to production costs, another important production-related element for biomethane – as with any energy from biomass – is the need to ensure environmental sustainability, especially when crop-based biomass or roundwood would be used.

Storage

The European gas and electricity systems are among the most stable and reliable in the world. Even in very hot summers or very cold winters the energy system provides the required energy. In the electricity grid, this stability is currently guaranteed by large dispatchable generation capacity. Also, gas infrastructure has been dimensioned to deliver sufficient energy during cold spells. The stability of the current system relies heavily on gas-fired generation and underground storage for large volumes of gas. In future low carbon energy systems, one of the main challenges will be to store large volumes of renewable energy.

With increased electrification, this will change. With increased wind and solar generation capacity it is expected that storage of electricity – in some form of energy carrier – will become necessary in large volumes. It is however expensive to store large volumes of electricity. Battery systems' efficiencies are improving and large technology companies have invested in scaling up battery production facilities, leading to rapid cost declines.

[7] Assuming a natural gas price of €20 and an efficiency of about 50%, http://www.eex.com/en/
[8] Further elaborated in chapter 3 and 4

However, costs are not likely to reach less than €80.000 per MWh of storage capacity within the next 35 years[9]. These high costs per unit of volume makes batteries unsuitable for long-term storage. Another possibility is (pumped) hydro storage. However, a GIS[10]-based study by JRC found EU-28 countries to have a limited realisable pumped hydropower storage (PHS) potential of 37 TWh[11]. This is approximately 4 days of the current EU power consumption.

Gas can provide the remaining storage requirements. Gas is routinely and cheaply stored in large volumes. Investment costs for creating underground gas storage are around €25/MWh. This makes gas very suitable for storing large volumes of energy over longer periods – for example for seasonal storage[12].

Transmission and distribution

Transmission and distribution grids – both for electricity and gas – create value by geographically linking supply and demand. This allows production to take place where it can at the lowest cost, and end use at places where it adds most value.

Transmission and distribution networks for electricity are not designed to meet weather induced peak demands of large amounts of additional electric heating. The balancing of the electricity system is delicate and requires supply to constantly match demand to avoid blackouts. Also, transmission power lines are often overhead lines, often perceived negatively by local communities which therefore often leads to opposition against the building of new lines. Even new underground lines meet local opposition in sensitive areas.

“The capacity of the gas grids is up to ten-fold of that of the electricity grids.”

The gas grid is designed to meet demand for heat, including the demand in severe winters. For this reason, in areas with substantial gas-fired heating, the capacity of the gas grids can be up to ten-fold of that of the electricity grids. Also, the balancing of the gas grid is relatively easy. Using ‘line pack’ (the volume of gas in the grid), imbalances within the hour can be facilitated, and some imbalance between supply and demand can be bridged for multiple hours without affecting supply to customers. This can add as much as 20 GW in flexible supply[13]. Once in place, gas grids have little impact on local residents, because they are mostly underground.

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[9] Ecofys et. al., 2017: Batstorm- Battery-based energy storage roadmap. Cost estimates include the full battery pack and are based on an exponential interpolation of battery costs estimates provided by IRENA, Epri, Rocky Mountain Institute, Bloomberg, EIA, Roland Berger, Deutsche Bank, Johns Hopkins University, Aalto University, Lazard and JRC.

[10] Geographic Information System.

[11] JRC, 2013: Assessment of European potential for pumped hydropower energy storage.

[12] Costs based on the replacement costs of the Gasunie storage facilities.

[13] See as example the average variation of line pack in the GRT Nord system: http://smart.grtgaz.com/en/stock_conduite/NordH.

Energy use

In homes and non-industrial commercial buildings electricity can supply all functionalities. Increasingly also, electricity is used in passenger transport. Electricity can also provide the low and medium temperature demands of many industrial processes. For energy-intensive high temperature industrial processes, the direct use of electricity is currently limited. However, electricity can be used to reach high temperatures and is already used in several high temperature processes, like in electric arc furnaces that are used in certain steel production processes, and furnaces to produce glass and in aluminium production.

In homes and commercial buildings, gas is specifically suitable for cooking, space and hot water heating, and in some cases cooling. It is also suitable for low to high temperature heat in industry and in some industries, gas is used as a feedstock. Gas can be used for the production of electricity, for example as back-up for wind power generation and solar.

Transport

Gas can be used in road transport, including passenger cars, light duty vehicles and trucks. Although the penetration of electric cars is increasing, biomethane can also be used for passenger cars and light duty vehicles, making use of existing and scaled up technology. Hydrogen-electric vehicles are seen as a promising future solution for passenger and freight transport. In the longer term it can be expected that the role of gas in transport focuses on heavy transport. This will be further investigated in Section 4.3.

Other sectors

There are other sectors where renewable gas might be used. For example, there are limited electric alternatives in agriculture. Renewable gas could be used for farming equipment and heating of greenhouses, in addition to renewable sources of heat like geothermal energy, and as a complement to electric heat pumps during peak demand.

Focusing the energy transition on electricity or also on gas?

Technological advances over the past decades allow us to harvest wind and solar energy more efficiently, and costs are decreasing further as the technologies are applied globally. Decreasing cost of generation makes these intermittent renewable electricity sources attractive. These developments have led to policy support and an increased share of electricity generated from wind and solar. It also means that proponents of the energy transition so far focus mainly on renewable electricity. At the start of the energy transition, renewable electricity was relatively easily and cheaply implemented, while the produced electricity could be used in a large variety of functionalities without end-of-pipe emissions. With the current penetrations of less than 30%, intermittency can be compensated by the available dispatchable power generation, using the flexibility (in volumes and capacity) of natural gas and other fuels to continuously match power supply and demand.

However, with higher penetration levels of wind and solar power, the difficulty of the intermittency of renewable electricity production will increase. Hour-by-hour, additional intermittent capacity will add supply at times when it is not necessarily needed, and create times of oversupply. To eliminate carbon emissions at all hours, climate neutral dispatchable back-up generation is highly valuable for the energy system.

With increasing intermittent supply, the need for back-up capacity will increase as well. At the same time, running hours of this capacity will decrease. This means the costs for building such capacity (capital costs) must be low while the variable costs for using such capacity can be higher without being detrimental to its business case. Batteries are an option for diurnal storage (short term peak storage), but they are very expensive per unit of energy stored and therefore it is unlikely that large-scale battery storage will be the preferred option for long-term storage. Pumped hydro power also helps, but the capacity is restricted by rainfall patterns and geographical limitations.

Running back-up generation capacity for longer periods requires storage of gaseous or solid fuels. In multi-year periods, there will be weeks in which electricity demand is exceptionally high while wind and solar supply is exceptionally low. To bridge these periods, a certain volume of energy must be stored.

All in all, as the energy system progresses towards full decarbonisation, a mix of technologies will be necessary to keep the energy system sustainable, i.e. secure, reliable, affordable, socially acceptable and environmentally friendly. To find the optimal mix, all possibilities must be investigated to the fullest. This report studies one of the possibilities in particular - the potential for renewable gas and the value it can add in a decarbonised energy system.

3 Renewable and low carbon gas in the EU by 2050

This study starts from the perspective that all gas consumed in the EU energy system by 2050 will have net zero greenhouse gas emissions. This could either be renewable gas or natural gas combined with CCS/CCU, also called low carbon gas.

Renewable gas is defined in this report as all gas produced from renewable sources. This includes methane and hydrogen produced from renewable electricity (Power-to-Gas) as well as biomethane. A scale-up of renewable gas can play an important role in the decarbonisation of gas supply. In this study, we focus on renewable hydrogen and biomethane as the two most important sources of renewable gas.

This chapter describes the potential production and production costs of renewable gas in the EU energy system by 2050. It also describes scenarios for future consumption levels of low carbon gas. We start with an overview of the overall potential. Subsequently, we discuss the sustainability of the assumed quantity of renewable gas, both in terms of greenhouse gas saving as well as wider sustainability impacts associated with biomethane production. Then we discuss biomethane and Power-to-Gas potentials and costs in more detail. And finally, we describe the viewpoints and possible future application of CCU and CCS in combination with natural gas.

This study does not estimate the future volumes of natural gas in the EU energy system. Section 3.6 describes potential scenarios for future natural gas consumption.

3.1 Total potential of renewable gas by 2050

Production of renewable gas is limited by the availability of low cost wind and solar power to produce renewable hydrogen and the availability of biomass resources to produce biomethane.

We estimate that it is possible to produce 122 bcm renewable gas by 2050 within the EU, while imports could further increase the potential. This is a prudent estimate of possible production within the EU within strict sustainability criteria. It consists of 98 bcm of biomethane plus 24 bcm of renewable hydrogen. The quantity of biomethane is much larger compared to renewable hydrogen because the production of renewable hydrogen is dependent on the availability of low cost renewable electricity. It is possible to increase the potential for renewable hydrogen by adding renewable electricity capacity on top of the very large increase in wind and solar PV that is assumed already. However, in our modelling this leads to an increase in the system costs. The 98 bcm of biomethane consists of 63 bcm of biomethane based on biogas from anaerobic digestion and 35 bcm of synthetic natural gas from thermal gasification, as will be further explained below.

3.2 Sustainability

Renewable and low carbon gas can only be scaled up in Europe if it is produced without adverse sustainability impacts, while environmental and social co-benefits would help its scale-up. In calculating the potential for renewable gas, we have carefully taken sustainability aspects into account. In this section we first explain how we ensure the sustainable production of biomethane including high greenhouse gas savings. Subsequently we discuss methane leakage and how it can be minimised.

3.2.1 Sustainable biomethane

The use of biomethane (as well as other forms of bioenergy) has many benefits. It can be easily stored and thus contribute to energy system flexibility and stability. Biomass production and processing contributes to the rural economy and job creation, plus biomethane can be produced domestically and thus reduces the dependency on energy imports. In recent years, the sustainability of all forms of bioenergy has been widely debated in the EU, with discussion focused on the sustainability of biomass feedstocks. If biomethane is to take an increased role in Europe's energy system, the sustainability of the associated biomass production has to be ensured.

Biomethane can be produced from agricultural residues and crops (via biogas) or from woody biomass, as will be further explained in section 3.3.1 below. Direct and indirect sustainability risks are mainly associated with crop cultivation and roundwood production. These risks have been widely documented and discussed[14] and will not be further discussed here.

Sustainable biomethane must lead to high greenhouse gas savings compared to the fossil alternative while preserving biodiversity and soil quality. Also, sustainable biomethane must not displace existing food and feed production nor lead to unwanted direct or indirect land use change effects. A simple solution to ensure sustainable biomethane production could be to refrain from using wood or crops for biogas. This is not the approach chosen in this study, since we believe that if done right and approached carefully, it is possible to use crops and certain wood types sustainably. We carefully assess which woody biomass types, which crop cultivation practices and which residues could be sustainably used, and in which quantities, to produce biomethane in the EU. This means that we restrict the production potential for biomethane to a relatively conservative 'no regret' potential produced from biomass that can be made available without negative sustainability impacts, and can even lead to positive impacts. On the agricultural side, we assume that residues such as straw and manure are used and no agricultural crops that are produced as the main crop are used to produce biomethane. Instead of the main crop, we include crops that are produced in additional to existing crop production in a 'sequential cropping' scheme.

[14] The EU introduced mandatory sustainability criteria for biofuels and biogas in the 2009 EU Renewable Energy Directive (RED) in response to growing concerns and the public debate on bioenergy sustainability. These sustainability criteria will be updated and expanded to woody bioenergy in the revised REDII Directive. The positions of various stakeholders in the debate can be viewed e.g. in three EC consultations on the topic.
https://ec.europa.eu/energy/en/consultations/preparation-sustainable-bioenergy-policy-period-after-2020
https://ec.europa.eu/energy/en/consultations/preparation-report-additional-sustainability-measures-solid-and-gaseous-biomass-used
https://ec.europa.eu/energy/en/consultations/indirect-land-use-change-and-biofuels, see further: http://task38.org/Sustainability_updated_2009.pdf

This means that two crops are produced on existing agricultural land within a year instead of one. This concept is not yet widely applied in Europe and is further explained in section 3.3.3 below.

On the woody biomass side, we assume that it is possible to use forestry harvesting residues, landscaping wood and a small share of wood thinnings, i.e. younger trees that are harvested from plantation forests to create more space and light for other trees to grow.

We assume that less than half of all agricultural crop residues and forestry harvesting residues can be collected, to leave sufficient biomass on the land to maintain soil quality. We also take into account that a portion of collectable residue material is used for other purposes.

This study does not assume a large-scale-up of algae biomass to be used for biomethane production. We are aware of promising new developments in this field and if low cost, large-scale algae cultivation solutions become available, the potential to produce sustainable biomethane in Europe and elsewhere could greatly increase[15].

Greenhouse gas emission reduction from biomethane

In international carbon accounting, biomethane has zero associated carbon emissions. The combustion of biomethane for power and heat production results in greenhouse gas emissions similar to those of natural gas. Yet in the process of growing the biomass feedstock, an identical quantity of CO_2 is captured from the atmosphere. This means that biomethane combustion emissions have a short carbon cycle and, according to the IPCC guidelines, count as zero emissions. At the same time, emissions occur in the cultivation, processing and transportation of biomass feedstocks. Taking these into account, the overall lifecycle greenhouse gas savings of biomethane compared to natural gas are typically 80 to 85% today. In the future however, lifecycle emissions will be further reduced when renewable energy is used in agriculture and processing. It is even possible to achieve negative overall emissions if biomethane upgrading and/or combustion emissions are captured and stored. In addition, negative emissions can also be achieved in the biomass growing phase by increasing soil carbon stock levels, for example by leaving a proportion of biomass residues on the field to decompose and be taken up into the soil as soil organic carbon or by either injecting biogas digestate to the soil or both.

The greenhouse gas saving potential of biomethane may be reduced, if its production causes land use change in the form of direct or indirect displacement of agricultural production and if this leads to the conversion of forests or other high carbon stock lands to new agricultural land elsewhere. In this study, we include only biomethane which does not lead to direct or indirect land use change, to ensure a high greenhouse gas saving from biomethane.

3.2.2 Methane leakage

In the gas production and use cycle, methane leakage is a great concern. In the World Energy Outlook 2017, the IEA investigated the methane leakage rates in the full natural gas chain and concluded that this rate is currently about 1.7% of the total amount of gas consumed. A kilogramme of methane, when released without combustion, is

[15] For example, Dutch engineering firm Inrada develops large-scale algae production solutions with the specific purpose to convert it to biogas that can be processed into biomethane. See http://www.inradagroup.com/seatech-energy/. Other promising projects are: http://www.seafarm.se/, and http://seagas.co.uk/.

estimated to be around 28 times more potent a greenhouse gas than a kilogramme of carbon dioxide[16]. This methane leakage rate therefore increases the global warming effect of natural gas by another 17%, relative to its CO_2 emissions. The IEA also concludes that the natural gas industry can reduce its methane emissions considerably, often by applying relatively simple and cheap measures. To fully realise the environmental benefits of gas, the industry must continue their efforts to avoid methane leakage in the near and long-term future. This section sets out the implications of moving to a renewable gas supply for the efforts around reducing methane leakage.

Methane leakages can occur across the entire gas chain, from extraction and processing to transmission and distribution. Extraction and processing of natural gas, together with transmission over long distances, accounts for the lion's share of methane leakage of the current gas supply (approximately 60% to 80%). This means that replacing natural gas with EU produced renewable gas would reduce the sources of the current methane leakages significantly.

Keeping methane leakage within the EU as low as possible requires continuing efforts of gas infrastructure companies to monitor and reduce methane leakage in their systems. Gas companies have individual programmes and best practices to reduce methane emissions. Operational rules can be adapted, after a case by case assessment, for example:

- TSOs can, where feasible, recompress gas during interventions that require emptying a pipeline, avoiding the release of methane emissions into the atmosphere;
- For gas pressure control systems: use of "auto-piloted" valves instead of "external pilot systems" enables pressure regulation without any gas emissions. Instead of natural gas, compressed air is used for pneumatic actuators. The compressors are electrically driven, in some cases by renewable sources or by cleaner-burning CHP (combined heat and power);
- Closed loop systems for truck transport of liquids to wells and treatment facilities, combined with recompression of natural gas flashing out of produced liquids on production sites and using these fuels for combustion (gas heater, glycol regeneration);
- Usage of hot taps for in-service pipeline connections, replacement or removal of unnecessary old equipment, lowering gas pipelines pressure before maintenance, replacement of pneumatic controls with air/electrical actuators.

Biogas and biomethane production also carries the risk of methane leakage. This leakage can be reduced to zero with the right industrial technologies:

- Using a closed digestate storage system to avoid methane leakage at the production stage;
- Equipping the upgrading module with an off-gas combustion system to avoid methane leakage during the biogas upgrading processes;
- Using high pressure pumps and regular maintenance of the sealings at the injection point to avoid methane leakages in grid injection.

There are also natural (non-anthropogenic) sources of methane emissions. Biomass used by the industry to produce biomethane will not contribute to these natural sources of methane emissions.

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[16] IPCC, 2015: Fifth Assessment Report (AR5)

3.3 Biomethane potential

Two main technologies exist to produce biomethane: anaerobic digestion and thermal gasification[17]. The first is currently widely used to produce biogas from agricultural biomass that can be upgraded to biomethane. The latter is an up and coming technology to produce biomethane from woody and lignocellulose biomass. As indicated in the previous section, it is well possible that further potential could emerge from, for example, large-scale cultivation of algae.

3.3.1 Two technologies to produce biomethane

Anaerobic digestion

This technology performs a series of biological processes in which microorganisms break down biodegradable material in the absence of oxygen. The process results in biogas and digestate. Biogas contains around 50% methane, the rest being mainly (short carbon cycle) CO_2. To enable its injection into the gas grid, biogas needs to be upgraded to biomethane with 97% methane content by removing the CO_2[18]. Digestate can be used as a fertilizer to enhance soil fertility.

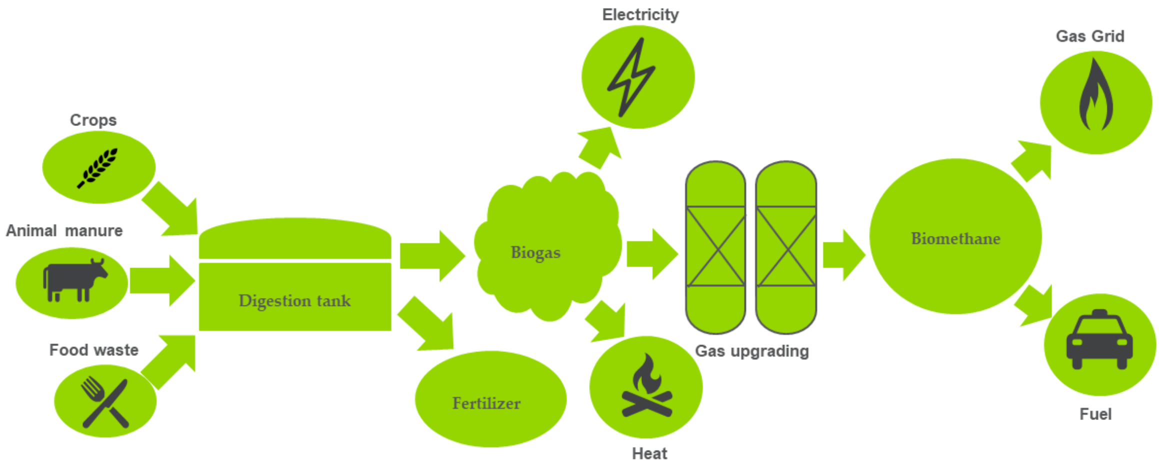

Figure 3 Schematic overview of the anaerobic digestion process

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[17] Additional processes to produce biomethane through gasification are under development, e.g. supercritical water gasification which transforms liquid biomass into biomethane.

[18] We note that in some countries, most notably the Netherlands and Belgium, the methane content of gas is about 80% today, due to the production of low calorific gas in Groningen. This means that biomethane used in these countries today should have a methane content of 80% instead of 97%. We assume that this gas will be fully used by 2050, meaning that all biomethane by then will have a 97% methane content.

Thermal gasification

In this technology, a complete thermal breakdown of woody biomass and consumer wastes takes place in a gasifier, in the presence of a controlled amount of oxygen and steam. A mixture of carbon monoxide, hydrogen and carbon dioxide is produced which is called syngas (synthesis gas). The gas is cooled and ash content is removed. In a gas cleaning unit, pollutants like sulphur and chlorides are separated. Methanation of the syngas is then performed in a catalytic reactor using nickel catalysts. With methanation, the cleaned gas is converted into biomethane, carbon dioxide and water. CO_2 and water are then removed in a gas upgrading unit.

At present, the production of biomethane from thermal gasification is small compared to the production of biomethane from anaerobic digestion in Europe: thermal gasification technology is not yet commercially available whereas anaerobic digestion is already used commercially in thousands of biogas plants across Europe. In developing our estimates, it is assumed that thermal gasification will have reached full commercial maturity well before 2050.

"The potential for biomethane is driven by the need to ensure sustainable production."

We estimate that by 2050 biomethane from thermal gasification will be cheaper than biomethane from anaerobic digestion, as will be further explained in section 3.4.

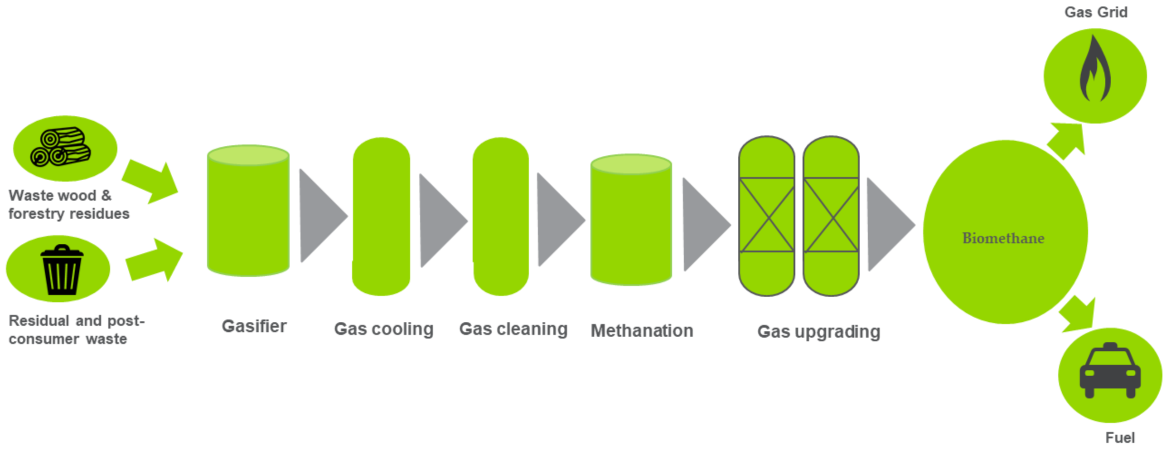

Figure 4 Schematic overview of the thermal gasification process

3.3.2 Biomethane potential

The total biomethane potential mainly depends on the assumed quantity of feedstocks and feedstock mix, as well as the assumed conversion efficiency of feedstock to biomethane. We considered both the production of biomethane from agricultural residues and sustainably cultivated crops through anaerobic digestion, plus biomethane from woody biomass and post-consumer waste through thermal gasification. The feedstock availability for biomethane is driven by the need to ensure sustainable production, as is discussed in section 3.2.1 above. Table 1 lists the feedstocks used to produce biomethane as included in this study.

Table 1 Feedstock categories and descriptions

Feedstock	Description	Assumed availability (dry tonnes)	References
Triticale and maize silage produced as sequential crops	Maize silage and triticale produced as additional (second) crop before or after the harvest of main crops on the same agricultural land.	130 mln tonnes assumed production on 50% of today's harvested area of wheat and maize (19 mln ha) within the EU excluding Nordics, Baltics and Ireland.	Eurostat, 2017: "Crop statistics"
Agricultural residues	Plant residues from the harvesting of agricultural crops: straw from cereal (wheat, barley, rye, and oat) and oil crops (rape seed, sunflower), maize stover and cobs, sugar beet leaves and residues from wine production. The category excludes grass.	50 mln tonnes assumed availability, based on using 67% of sustainable collectable residues, assuming that over half of agricultural residues is left on the field to ensure soil quality.	(Iqbal et al. 2016): "Maximising the yield of biomass from residues of agricultural crops and biomass from forestry".
Biodegradable wet waste	Food waste: mixed food waste plus vegetable waste.	7 mln tonnes availability. Does contain animal and mixed food waste. All available biomass is assumed to be used for biogas production.	(Elbersen et al. 2014): "Outlook of spatial biomass value chains in EU28".
	Wet manure: animal faeces and urine.	16 mln tonnes availability, based on the assumption that half of wet manure is used for biogas production.	Elbersen et al. 2014): "Outlook of spatial biomass value chains in EU28".
	Sewage sludge: sludges and liquid wastes from waste treatment.	2 mln tonnes	(Kampman et al. 2017): "Optimal use of biogas from waste streams".
Woody residues	Bark, branches and tops, that are left as residues from the harvesting of trees from forests.	15 mln tonnes, assumed a collection rate of 20%, the other 80% stays at the forest floor to ensure soil health and biodiversity.	(Ecofys, 2013): "Low ILUC potential of wastes and residues for biofuels".
	Thinnings: smaller trees that are cut to make forests less dense and thereby create space for other trees to further growth.	6.6 mln tonnes, assumed that 2% of total annual roundwood harvest from EU forests by 2050.	(Ecofys and Hohenheim 2016): "Maximising the yield of biomass from residues of agricultural crops and biomass from forestry", (Ecofys 2017): "Beschikbaarheid houtige biomassa voor energie in Nederland".
	Landscape care wood & roadside verge grass.	26 mln tonnes, this is 80% of the total assumed collectable quantity.	(Elbersen et al. 2014): "Outlook of spatial biomass value chains in EU28".
Residual and post-consumer waste	Municipal Solid Waste: includes the biomass share of municipal waste total waste generated from municipality.	17 mln tonnes, this is 10% of the total assumed available quantity, assuming a 30% decrease in MSW compared to today.	Eurostat, 2017: "Municipal solid waste by operations".
	Solid Recovered Fuel and Refuse Derived Fuel: derived from commercial and industrial waste and construction and demolition waste.	1 mln tonnes, this is 10% of the total assumed available quantity, assuming a 30% decrease in waste compared to today.	(CEMBEREU & ERFO, 2015): "MARKETS FOR SOLID RECOVERED FUEL: Data and assessments on markets for SRF".
	Waste wood from wood processing, paper and pulp and forestry.	7 mln tonnes, this is 20% of the total assumed available quantity, assuming a 30% decrease in waste compared to today.	Eurostat, 2017: "Generation of waste by waste category".

Based on this feedstock mix, with their respective energy densities, we calculate a total EU biomethane potential. We assume a biomass to biomethane yield of 0.36 m^3 biomethane per kg of biomass feedstock for upgraded biogas from anaerobic digestion and 0.55 m^3/kg for biomethane from thermal gasification. This leads to an estimated total EU biomethane production potential of 98 bcm per year by 2050 within the European Union [19] [20]. This number consists of 63 bcm produced through anaerobic digestion and 35 bcm produced through thermal gasification.

A breakdown of the assumed biomethane production potential per feedstock category is provided in Figure 5 and Figure 6 below. The biomethane potential from individual feedstocks is rounded so they do not always add up to the total.

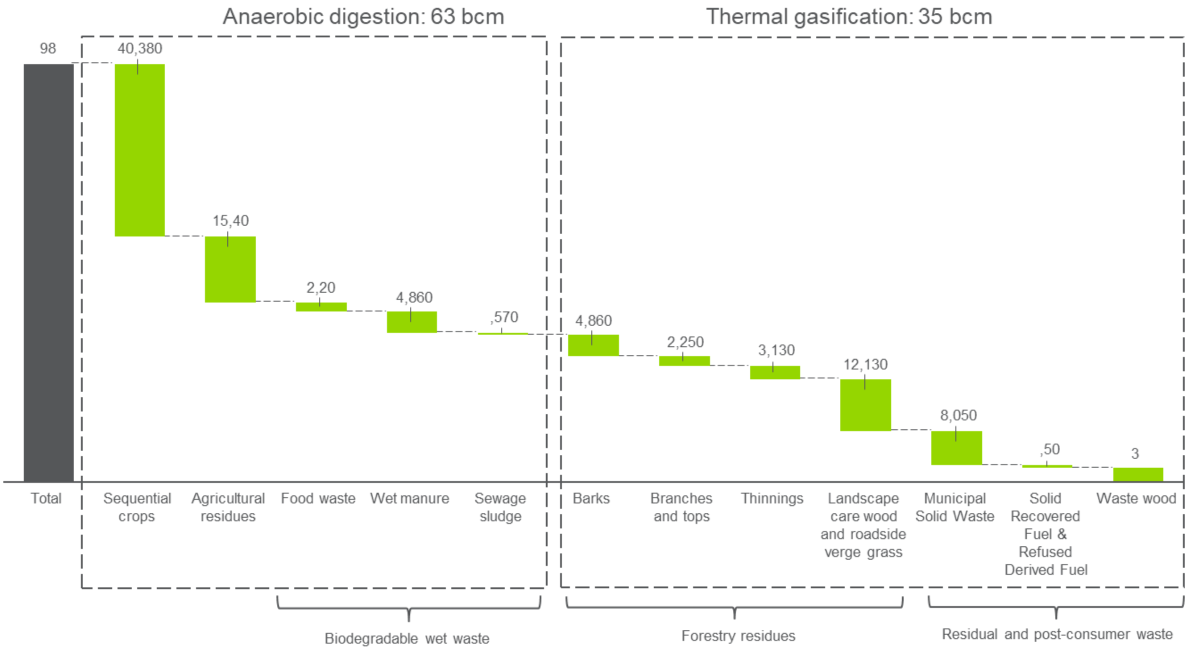

Figure 5 Biomethane potential per conversion technology and feedstock type by 2050

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[19] This value is calculated using gas yield (m^3/kg of volatile solid) of 0.36 for biomethane from upgraded biogas (anaerobic digestion) and 0.55 for biomethane from thermal gasification for their assumed mix of feedstocks. The methane potential, in addition to the design configuration of plants and plant operating conditions, depends significantly on the composition of feed mix. The biomethane yield from digestion has a wide range (0.21 m^3/kg for manure, 0.36 m^3/kg for maize, 0.40 m^3/kg for bio-waste; biogas yields are retrieved from http://publications.jrc.ec.europa.eu/repository/bitstream/JRC104759/ld1a27215enn.pdf, which are then adjusted for biomethane content of 55% in biogas) and with a large share of maize and triticale in the mix it is not completely implausible to assume that the yield would increase towards the high end of the range. Thermal gasification, on the other hand, is currently facing some technical challenges in the gasification step, especially with regards to feedstock treatment but syngas conversion into biomethane is already quite efficient. It is assumed that by 2050 with advances in research, the impacts of microbial cultures on biological transformation of organic matter into biogas and the effects of different combinations of feedstock mixtures on biomethane yield will be better understood. Also, an improvement in feedstock treatment methods is expected. These expected developments will allow for an increase in the efficiency of both processes. In our calculations, we used biomethane LHV of 33 MJ/m^3 to derive the energy content against the m^3 of biomethane produced. Finally, the biomethane potential is presented in natural gas equivalent terms using natural gas LHV of 38.2 MJ/m^3.

[20] Biomethane LHV (33 MJ/m^3) is for pure biomethane which is calculated using LHV (50 MJ/kg) of biomethane retrieved from the EU-RED and then corrected for its impurities and CO_2 content.

Figure 5 above provides the shares of biomethane potential per feedstock type. Sequential crops (40 bcm, further explained in section 3.3.3 below) have the largest share amongst all feedstocks followed by agricultural residues and landscape care wood and road side verge grass (15 and 12 bcm, respectively). Figure 6 below provides the percentage contribution of feedstocks to the total biomethane potential from their conversion technology.

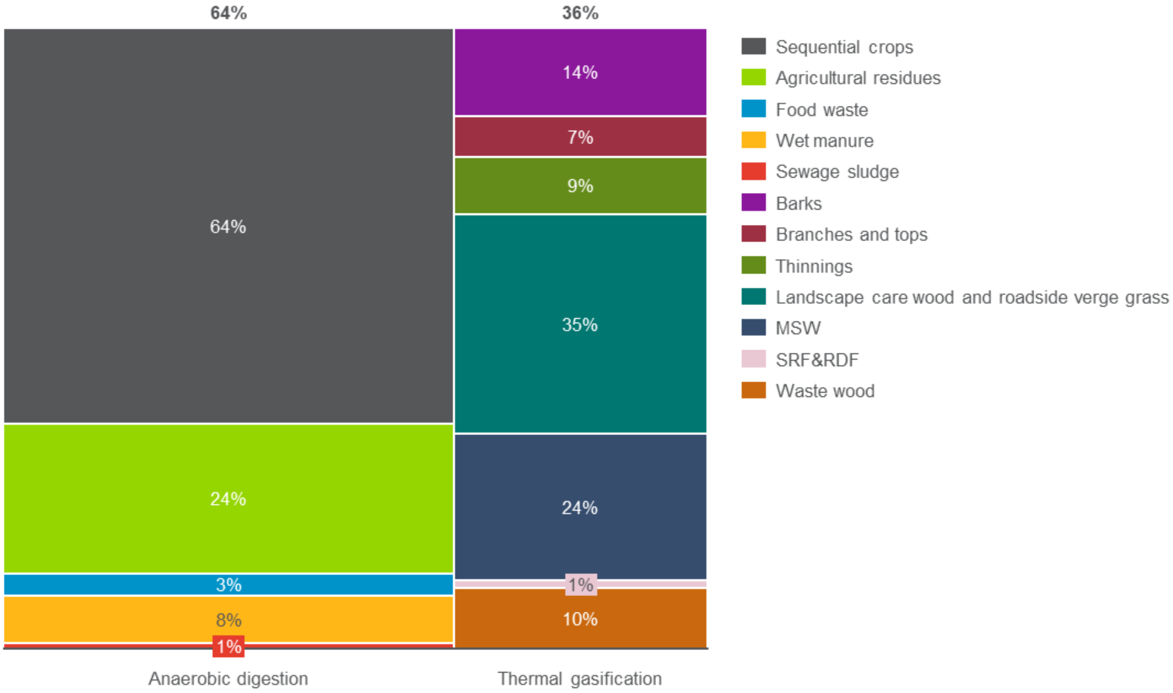

Figure 6 Percentage share of the total EU biomethane potential per conversion technology and feedstock type by 2050

3.3.3 Biogasdoneright

We assume in our analysis that the single largest contribution of biomass for biomethane comes from maize silage and triticale produced as sequential crops. These are crops produced as an additional (second) crop before or after the harvest of the main crop on the same agricultural land. We estimate that 40 bcm of biomethane can be produced from maize silage and triticale produced in this way. This requires some further explanation since sequential. cropping is hardly applied in Europe today. Our view on the potential for sequential cropping is based on an optimised concept developed in Italy called Biogasdoneright[21]. Biogasdoneright is a departure from a traditional way of farming towards more innovative and sustainable farming practices. It increases the agricultural productivity of existing farmland without negative environmental impacts and without direct or indirect land use change effects. Biogasdoneright leads to co-benefits such as decreasing soil erosion risks, an increase in on-farm biodiversity and a potential increase of the soil carbon content by leaving more agricultural residues on the land. It could also result in negative carbon emissions.

[21] https://www.consorziobiogas.it/wp-content/uploads/2017/05/Biogasdoneright-No-VEC-Web.pdf

Ecofys assessed the environmental sustainability of Biogasdoneright in Italy together with experts from Wageningen University and found it a promising concept[22]. We have not yet evaluated the soil carbon accumulation as this would require multi-year carbon budget assessments.

Biogasdoneright in the Po valley in Italy

Ten to fifteen years ago, a group of farmers in the Po valley in Italy developed a new practice for producing biogas. They kept producing crops for food and feed for their cows, as they always had. Like other farmers in the region they used their milk to produce cheese, as they always had. Supported by a biogas subsidy scheme, the farmers invested in anaerobic digestion biogas plants, using manure and maize to produce biogas. They did not want to use their existing maize production for biogas, because this would mean they had to buy animal feed on the market instead of producing it themselves. To control the quality of their cheese they wanted to continue to grow their own feed. So, they started to experiment with cultivating a second crop after the harvest of their main crops. Previously, their land had been fallow in winter, as is usual in Europe. Now, they started to produce two crops a year. The experiment worked and more farmers joined the initiative. They developed a set of best practices including strip tillage to keep soil disturbance to a minimum, using light machinery to avoid soil compaction and drip irrigation to minimise water consumption. They distribute the digestate, a nutrient-rich co-product of biogas production, back to their land thereby reducing the need for synthetic fertiliser. The farmers coined the term 'Biogasdoneright' for their way of farming and have applied it ever since.

We assume a nearly EU wide scale-up of sequential cropping. In our analysis, we assume that maize silage and triticale are cultivated as second crops on 50% of all agricultural land that is currently used to produce wheat and maize respectively within the EU, excluding Nordic countries (Finland, Denmark, Sweden), Ireland and Baltic States (Estonia, Latvia and Lithuania) where climatological conditions may not support the introduction of the concept. We therefore assume that sequential cropping is introduced by 2050 on 19 million hectares of existing agricultural land, or 11% of today's total utilised agricultural area (UAA) in the EU-28[23]. Zero additional hectares of land are converted to agricultural land, not directly nor indirectly, and no existing food and feed production is displaced towards biogas production.

Biomethane imports from Ukraine and Belarus

In this study, we assume that biomethane will be produced in the EU from EU-produced biomass feedstock. Based on a number of assumptions as outlined above, this leads to an estimate that 106 bcm of biomethane could be produced within the EU by 2050 annually. It is well possible that the future consumption of biomethane in the EU can be increased by imports from outside the EU. We can for example consider future biomethane imports from Ukraine and Belarus, countries whose gas pipeline network are connected to the EU network. We assessed the biomethane production potential for both countries using the same feedstock assumptions as applied for the EU. We assume that both countries would dedicate 60% of their available biogas feedstocks to production for the EU market. Based on this, a total quantity of **20 bcm of additional biomethane** could become available for the EU market annually.

[22] https://www.ecofys.com/files/files/ecofys-2016-assessing-benefits-sequential-cropping.pdf
[23] Utilised Agricultural Area (UAA) in the EU (2013); ~175 million hectares: http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=ef_oluft&lang=en

We assume that the second crop on average yields 40% of the biomass of the main crop on the land. This is a relatively conservative estimate, given that in Italy the second crop yields up to 60% of biomass compared to the main crop yield. We do note that, to better understand the potential of sequential cropping in the EU, a more detailed assessment would be needed, looking at a range of possible crop combinations in sequential cropping schemes.

3.4 Biomethane production costs

The combined weighted average cost per unit of biomethane is estimated to be around 52 €/MWh$_{th}$ in 2050. This is a significant decrease compared to today's costs of around 100€/MWh$_{th}$[24]. The calculated figure is based on a combination of production costs of biomethane from anaerobic digestion and of biomethane from thermal gasification, assuming a 64:36% split of the biomethane potential (see Section 3.3. above). The assumed average costs for biomethane in 2050 are 60 €/MWh$_{th}$ for anaerobic digestion and 37 €/MWh$_{th}$ for thermal gasification. These costs are production costs from a societal perspective. This means that we use the assumed average technical lifetime of production facilities of 30 years, do not take into account any subsidies and include only the societal WACC (weighted average cost of capital) which is assumed to be 3.5%. Figure 7 shows the Levelised Costs of Energy (LCoE) of Anaerobic Digestion and Thermal Gasification. LCoE is the total costs (including capital expenditure) of producing a unit of energy.

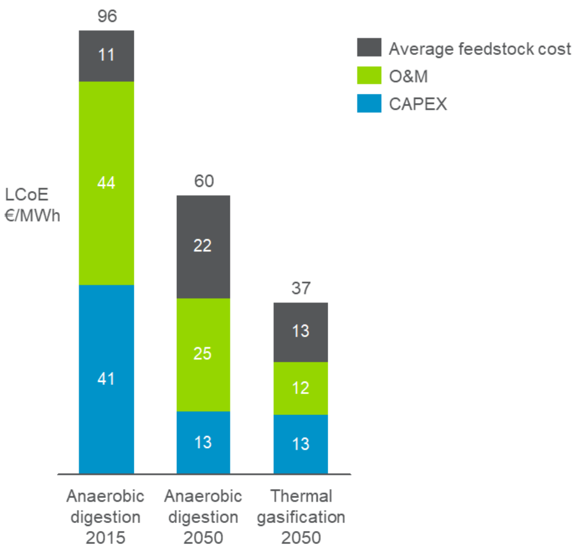

Figure 7 LCoE breakdown for anaerobic digestion and thermal gasification

[24] Costs include feedstock costs, CAPEX and O&M costs. Feedstock costs are based on EBA feedstock data whereas CAPEX and OPEX figures, against a plant size of 2 MW, are retrieved from "DECC, RHI Biomethane Injection to Grid Tariff Review (December 2014)": https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384202/Biomethane_Tariff_Review_-_Government_Response_-_December_2014.pdf

The significant cost reduction of biomethane production is due to the assumed commercial availability of relatively low cost biomethane from thermal gasification as well as a significant lowering of capital and operating costs of anaerobic digestion. We anticipate the following cost reductions:

- Process efficiency improvements, mainly via an increased throughput (with the same conversion efficiency), that lowers the capital cost per unit of biogas;
- Scale up of average production installation size, with capacities for digestion-based biogas increasing from the current <2 MW to 6 MW units by 2050 and assumed 60 MW for gasification-based units;
- Assumed large-scale installations to produce biomethane from multiple biogas production units, leading to lower biogas upgrading costs[25].

We assume an increase of average feedstock costs for anaerobic digestion-based biomethane because we assume that the scale-up potential for low cost residues is significant, yet still limited. For further scale up we assume the use of sequential crops which are low cost compared to main crops, yet more expensive than e.g. manure.

The weighted average cost per MWh for anaerobic digestion is higher than thermal gasification. The primary reason is the lower energy content per tonne of biomass. This is because the end product from anaerobic digestion is biogas which is further upgraded to biomethane by removing CO_2, resulting in a near-pure methane gas. We assume the biomethane content of biogas to be 55%[26], while the rest of the biogas generated contains mostly CO_2 and a small percentage of water and pollutants.

The most important reason for the difference in costs between the two biomethane production processes is a large difference in biomass to biomethane conversion efficiencies, which are 0.36 m^3 of biomethane per kg of feedstock for biomethane from anaerobic digestion[27] and 0.55 m^3/kg for biomethane thermal gasification. The assumed higher cost for anaerobic digestion is also linked to higher investment costs (CAPEX), as can be seen in Table 2. Another reason for the cost difference is the higher operation and maintenance costs (O&M) for the anaerobic digestion route.

Table 2 CAPEX and OPEX for anaerobic digestion and thermal gasification

Technology	2015 CAPEX (M€/ MW)	2050 CAPEX (M€/ MW)	Operation & Maintenance (% of CAPEX)
Anaerobic digestion	5.63[28]	1.84[29]	6-10%
Thermal gasification	1.87[30]	1.64[31]	5%

[25] CIB and CRPA, The development of biomethane: a sustainable choice for the economy and the environment. Notes for the elaboration of a road map for the development of biogas done right and biogas refinery technologies in Italy (February 2017).
[26] This is an assumed average figure. The methane content of biogas can be either higher or lower, depending on the composition of feedstocks used.
[27] Biomass to biogas yield is assumed to be 0.65m^3/kg. This biogas has a methane content of 55%. Upgraded biomethane has a yield of 0.36 m^3/kg, which is much lower than the biomass to biomethane yield through the thermal gasification route.
[28] DECC, RHI Biomethane Injection to Grid Tariff Review (December 2014). https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384202/Biomethane_Tariff_Review_-_Government_Response_-_December_2014.pdf
[29] CIB and CRPA, The development of biomethane: a sustainable choice for the economy and the environment. Notes for the elaboration of a road map for the development of biogas done right and biogas refinery technologies in Italy (February 2017).
[30] Low Carbon Innovation Coordination Group, Technology Innovation Needs Assessment (September 2012). https://www.carbontrust.com/media/190038/tina-bioenergy-summary-report.pdf
[31] Ecofys calculations based on TRL development.

In 2050, we assume that most on-farm agricultural residue-based feedstocks will be used on-farm to produce biogas and will be available for free. This is not the case for agricultural residues with established markets, such as straw and forestry residues, for which we include feedstock collection and transport costs. The latter can be significant depending on the logistics. Due to on site production of biogas from sewage sludge and wet manure, the costs are expected to be zero. With food waste, the costs of processing are assumed to be negligible. For (the biomass fraction of) municipal solid waste and waste wood, processing costs might be needed to separate organic matter from the undesired materials like plastics, metals, etc. Sequential crops require much lower production costs than conventional maize silage[32]. Table 3 provides the assumed feedstock costs for 2050.

Table 3 Feedstock costs[33]

Feedstock type	2050 Feedstock cost (€/ Oven Dried Tonne)
Sequential crop (triticale and maize)	90
Wheat straw, sugar beet tops and pulp, road side verges, citrus pulp, husks	61
Food waste	0
Wet manure	0
Sewage sludge	0
Barks	92
Branches and tops	92
Thinnings	92
Landscape care wood and roadside verge grass	92
Municipal Solid Waste (MSW)	12
Solid Recovered Fuel/Refuse Derived Fuel (SRF/RDF)	0
Waste wood	12

3.5 Renewable hydrogen potential

Renewable hydrogen is the product of a 'Power-to-Gas' process: the production of gaseous fuels from (mostly low cost) electricity. There are two main Power-to-Gas processes. The first is producing hydrogen (H_2) via electrolysis of water, using electricity. The second is to, subsequently, use hydrogen to hydrogenate CO_2 in a methanation process to produce methane (CH_4). Methane produced via methanation is often also referred to as synthetic methane. This process will be further described in the section below.

This report focuses also on renewable hydrogen as an energy carrier, produced from renewable electricity. In the future energy system, with its high penetration of intermittent renewable electricity, the potential volume for renewable hydrogen is considerable.

[32] Cost for conventional maize silage is 122 €/ODT whereas for sequential crops it is around 90 €/ODT, similar costs are assumed for 2050. Ecofys and WUR, Assessing the case for sequential cropping to produce low ILUC risk biomethane (November 2016). https://www.ecofys.com/files/files/ecofys-2016-assessing-benefits-sequential-cropping.pdf

[33] It is not possible to accurately predict feedstock costs as they are very volatile and depend on numerous factors. No detailed assessment was carried out to project cost figures for feedstocks. All cost figures for 2050 are based on expert judgement.

The electrolysis of water to produce hydrogen is proven technology. Hydrogen is used for many industrial processes already today, e.g. in hydrogenation reactions in the chemical industry (ammonia) or in refineries. It can also be used as a fuel for heating and transport. The advantage of hydrogen is that it has no greenhouse gas emissions upon combustion, and that no methanation step is required in the Power-to-Gas process. A disadvantage of hydrogen is that feeding it into the existing gas infrastructure would require adaptation of end use applications (and some adaptation of the gas infrastructure system).

"Producing renewable hydrogen creates value in future energy systems."

Renewable gas produced from power allows better use of the power generation capacity by increasing the ratio between feed-in renewable electricity and installed capacity (e.g. the utilisation of renewable electricity that would otherwise be 'curtailed' when there is no demand or storage capacity). Converting this Power-to-Gas allows excess renewable electricity generation to be stored.

Synthetic methane

Synthetic methane is a promising production source for renewable gas. We understand synthetic methane here as methane produced from residual CO_2 and hydrogen. It offers the opportunity to valorise CO_2 emissions from other industrial or biological processes acting as an accelerator of decarbonation of the economy.

Production of synthetic methane can be combined with the production of biomethane at Biogasdoneright farms. By using renewable power to produce hydrogen, and combine this with the short carbon cycle CO_2 that comes available from the upgrading of biogas to biomethane, it is possible to produce synthetic methane. In doing this, the efficiency of the conversion process is greatly improved. Also, negative emissions can be achieved when applying CCS when using the synthetic methane. This means the rural production of biomethane and synthetic methane will help electricity grid stabilisation, offering new kind of services, with multiple synergy effects[34].

Disadvantages of the production of synthetic methane is that it is considered to be a developing technology, and the methanation of hydrogen involves some conversion losses of energy. Also, additional capital expenditure is needed for the methanation process.

What is the potential for EU produced renewable gas from power by 2050?

In our analysis, the volume of renewable hydrogen and synthetic methane depends on the electricity generation mix. The volume of low cost electricity (being economically feasible to convert into gas) is strongly related to the installed wind and solar power generation capacity. To calculate the potential for renewable hydrogen, an assumption must be made on the share of production of hydrogen and methane.

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[34] It is also possible to produce hydrogen from dedicated (far offshore) wind parks. This would eliminate the need for (expensive) subsea power cables (a pipeline is per MW much cheaper than a power cable) and moreover, the connection of that power cable to the onshore backbone (and eventual expansion of that backbone).

We have chosen to assume that the entire volume of surplus renewable electricity will be used to produce hydrogen that will be used in industry in the vicinity of the production site. This is linked to the expectation that industry will use this supply of hydrogen in their processes and the replaced biomethane will be used in the gas infrastructure, possibly with hydrogen mixed in. Producing hydrogen without methanation lowers the costs for Power-to-Gas investment as only one processing step is required.

The resulting potential equates to 24 bcm of hydrogen in methane energy equivalent. The analysis underpinning this number will be further described conjointly with back-up power technologies and residual power demand in Section 4.2.3.

Renewable hydrogen production cost

The costs related to producing renewable hydrogen depend mainly on two factors: the cost of electricity per unit of hydrogen produced (taking into account the efficiency of the electrolyser) and the capital costs. In this study, only low-cost electricity is used to produce renewable hydrogen. This means electricity with low alternative value and low marginal costs is converted high value hydrogen. Therefore, the added value of renewable hydrogen production is quite high.

The costs for installing the capacity are substantial. It is therefore essential to have sufficient running hours to make the investment worthwhile. How this can be quantified is explained as part of Section 4.2.3.

Producing renewable hydrogen creates value in future energy systems. Optimising the installed capacity and running hours with the available electricity surplus in a scenario, maximises the use of intermittent renewable electricity by minimising curtailment. This benefits the entire system as electricity that would otherwise be wasted is upgraded to a fuel that helps balance the system and which has value for industry and other uses. The costs of producing renewable hydrogen are highly dependent on the final configuration of the future power system. The cost figures for producing hydrogen as well as the analysis behind the costs are therefore presented in detail with the description of back-up power technologies and residual power demand in Section 4.2.3.

The resulting overall[35] costs for producing hydrogen are 23 €/MWh in the scenario with renewable gas.

3.6 The role for low carbon gas

In addition to renewable gas, there is the possibility to use natural gas in combination with CCS to provide the benefits of natural gas without emissions. This is referred to as ‘low carbon gas’ in this report. The potential for low carbon gas is highly dependent on the level to which carbon capture is implemented throughout Europe. The availability of natural gas resources is unlikely to be the limiting factor.

Our analysis does not include a bottom-up approach of CCS or CCU capacities, we have not estimated potential volumes of low carbon gas (natural gas combined with CCS/CCU). Rather, we have included an indication of the expected cost savings when more low carbon gas is viably included in the energy mix.

[35] This includes capital expenditure

We have capped our analysis at the volumes indicated in the International Energy Agency (IEA) Energy Technology Perspectives (ETP) Beyond 2 Degrees scenario (B2DS). Here, 2050 EU-28 primary energy consumption of natural gas roughly equals 132 bcm[36].

Looking at the future of gas, forecasts show that gas demand in the EU in 2050 will be lower compared to today's consumption of 465 bcm per year[37]. The IEA forecasts the future developments of energy consumption in two authoritative reports each year: World Energy Outlook (WEO) and ETP. Both reports contain several scenarios including a scenario that starts from the perspective that greenhouse gas emissions will be strongly reduced to mitigate climate change. The latest WEO, published in November 2017, contains the Sustainable Development Scenario (SDS), in which global CO_2 emissions are reduced to 18 Gt per year by 2040[38]. ETP 2017, published in June 2017, includes the B2DS, which starts from the target to limit the global temperature increase to 1.75°C, in line with the "well below 2°C" target of the Paris Agreement. Both IEA forecasts run to 2040. We took the forecasts for natural gas consumption in the EU in both the SDS and the B2DS scenarios and extrapolated the consumption numbers to 2050. The result is a forecast of 132 bcm natural gas in 2050 in the B2DS[39] while the WEO 2017 SDS forecasts that EU natural gas consumption will fall to 343 bcm by 2040, which extrapolates to 279 bcm in 2050.

Unfortunately, the IEA is not clear on the extent of the role of CCS in the scenarios above. It is however inherent to full decarbonisation that any use of natural gas will have to be combined with CCS. The current study works with this assumption, but does not forecast how much natural gas will be used in the EU energy system by 2050. We assume that the numbers as provided in the IEA climate change scenarios provide a good indication of what could be possible. The use of natural gas by 2050 combined with CCS assumes efficient mitigation of methane leakage emissions, as explained in section 3.2.2. How much gas will be used in the future energy system depends heavily on the choices made in the various sectors and will be elaborated on in Chapter 4.

3.6.1 Carbon capture and storage or utilisation

There are two main applications of carbon capture. The first and best-known application is the 'end-of-pipe' solution for power plants and industrial facilities, where the CO_2 that results from the use of natural gas is captured and thereby prevented from entering the atmosphere. This is a demonstrated technology. Another application is capturing CO_2 during the steam methane reforming (SMR) process, in which natural gas is converted to hydrogen. Currently, around 95% of hydrogen is obtained from fossil fuels, a process in which significant amounts of CO_2 are produced as a by-product. Capturing the CO_2 from this process would make the hydrogen carbon-neutral. CCS is a well-known technique. At present, the technique is mostly used to enhance oil recovery.

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[36] IEA, 2017: Energy Technology Perspectives 2017, Beyond 2 degrees scenario
[37] Eurostat, 2017: Natural gas - Gross Inland Consumption 2016 (nrg_103m)
[38] Global greenhouse gas emissions currently stand at around 50Gt annually and were 38Gt in 1990 (IPCC 5th Assessment Report). A decrease to 18Gt thus represents a 53% decrease by 2040 compared to 1990 levels
[39] IEA, 2017: Energy Technology Perspectives 2017, Beyond 2 degrees scenario

In Norway, CCS is used with the single objective of reducing CO_2 emissions; an example is the Sleipner project at a natural gas production site in the North Sea. The combination of SMR with CCS/CCU is not commercially available yet, although several pilot plants are currently testing it[40].

Once captured, there are two approaches to deal with the captured CO_2. The most widely known approach is to store CO_2 underground, in depleted gas fields or dedicated salt caverns. This is CCS. If the CO_2 is used for other purposes, this is known as Carbon Capture and Utilisation (CCU).

An additional configuration is methanation of renewable hydrogen with CCU. As methanation requires CO_2 to convert hydrogen to synthetic methane, a closed system could be developed with CCU and natural gas combustion. When the CO_2 for methanation comes from CCU in combination with a gas power plant or industrial process, it creates a system in which the carbon is continuously reused. Moreover, if biomethane is used in the gas-fired power plant or industrial process, negative emissions can be achieved if combined with (semi)permanent[41] use or storage. Biomethane producers can play an important role in this process by using their biogenic CO_2 streams and grid connections for gas and electricity to produce methane from electrolysis and methanation, see section 3.5 above.

3.6.2 What are the limitations of CCS?

The most important limitation for the application of CCS is the need for long-term storage, its costs and its political acceptance (socially and environmentally). On the one hand, several EU Member States have significant storage capacity with large underground gas reservoirs that are (almost) depleted, while other member states have limited capacity. Political and social attitudes towards CCS differ between countries. Any inclusion of CCS solutions in future scenarios should therefore be based on bottom-up calculations, taking into account national specificities (storage availability, local opposition, political will, environmental requirements, Health & Safety regulations, etc.) and the effect of long-term carbon prices that could increase the number of more profitable CCS projects.

3.6.3 The role of CCU and CCS

There is considerable discussion on the future role of CCU and CCS in the energy sector. Some see it as essential to keep global warming well below 2ºC, others see it as an expensive technology with limited applicability. With low and further decreasing prices of wind and solar, the competitiveness of fossil gas with CCS is under pressure. Several European countries have included ambitious targets for CCS in their climate policies (e.g. the Netherlands) but so far there are only two operating plants in Norway and three more proposed or under construction (two in the UK, one in Norway). There are also several pilot plants spread out throughout Europe, at various development stages[42]. Outside Europe, there is considerable expertise with CCS in countries such as Canada, USA and China.

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[40] IEAGHG, 2015: Understanding the Potential of CCS in Hydrogen Production.
[41] For CCU to qualify as a decarbonisation measure, the products that are produced with CO_2 must have a sufficiently long lifecycle. Ideally the carbon is never released back to the atmosphere, but also with very long lifecycles (decades) and a cycle of CO_2 use and release, significant amounts of CO_2 can be kept out of the atmosphere.
[42] https://www.globalccsinstitute.com/projects/large-scale-ccs-projects

4 Value created by using renewable and low carbon gas

Having established the potential for renewable and low carbon gas in Chapter 3, this chapter will discuss in what way renewable gas can be used to add maximum value in the energy system. We explain the reasoning behind the savings and describe the methodology behind the quantification (technical details are provided in the Annex). The chapter starts with an allocation of the overall potential for renewable gas over all sectors in which it might be used. Subsequently we model the societal cost savings that are realised through the use of renewable gas in the buildings, electricity production and heavy transport sectors.

4.1 Allocation of renewable and low carbon gases to sectors

Gas has many potential roles in the future energy system. The available volume of renewable gas must be distributed across the sectors. This section will highlight the sectors where it can be deployed advantageously. We describe per sector how renewable and low carbon gas create value compared to alternatives. Subsequently, we explain the focus of our quantification and how we allocate renewable gas potentials across the different sectors in the overall energy system. The allocation is not limited to the sectors that are part of the detailed quantification.

The following sectors have been included in the allocation.

Buildings sector

The buildings sector is one of the key focus sectors of this study because of the large financial and practical impact on house owners and the existence of competing technologies with and without renewable gas. In addition, there is insufficient insight in the value of gas in this sector, looking at a fully decarbonised energy system.

In large parts of Europe, a big part of a building's energy use is for space heating, currently often relying on fossil fuels. The most-discussed low carbon options are distribution of renewable heat, which can be attractive in high-density urban areas, and electric heat pumps, using renewable electricity. However, electrifying heating in buildings requires high levels of insulation to maintain comfort levels on cold days. This is because heat pumps work with low capacities (in view of investment cost) and low temperature heat delivery systems (in view of performance), limiting the amount of heat loss that can be compensated for. Besides, electricity generation, transmission and distribution expansion is required to meet higher electricity demand peaks[43].

“Gas has many potential roles in the future energy system.”

[43] An additional complication is that high levels of insulation trap heat in buildings, increasing the cooling demand in summer.

Opting for the use of renewable gas in the building sector can create great value for the energy system. Gas-fired boilers, hybrid and gas-fired heat pumps can deliver peak demand at lower societal costs. They can also make use of the existing heat delivery systems, avoiding replacement costs in existing buildings. It will also make better use of existing gas transmission and distribution infrastructure, reducing investments in alternative infrastructures.

Electricity generation

Wind and solar will be the mainstay of renewable electricity production in the future. However, intermittency of these renewable electricity generation sources requires smarter electricity grids, wide-spread introduction of flexibility measures, and higher levels of (seasonal) storage and back-up capacity. Full electrification would also require upgrading electricity transmission and distribution infrastructure to meet demand increase, production volatility and more frequent, less predictable and higher peaks on both the demand and generation side.

In a decarbonised energy system without renewable gas, residual demand has to be met by large-scale power storage, natural gas- or coal-fired power plants with CCS or biomass plants[44]. With renewable gas and low carbon gas, efficient gas-fired power plants can be used to provide back-up capacity in combination with storage of renewable gas. This also means better use of the existing infrastructures and less investment in replacement electricity infrastructure. Gas infrastructure is well developed in large parts of the EU and has a remaining lifetime far beyond 2050.

Heavy Duty Transport

The search for emission-free options heavy duty transport is ongoing. Heavy duty transport generally requires energy carriers with high energy density such as biodiesel, bioethanol or Liquified Natural Gas (LNG). Recently, several manufacturers have announced promising battery-electric[45] and hydrogen-electric trucks[46] for freight transport but these promises are yet to be realised. This means that there is a role to play for renewable gas in the form of bio-CNG/LNG, as an efficient, sustainable and scalable alternative to other energy dense fuels.[47] A societal costs comparison for heavy duty transport is included in section 4.3. In this study we assume that electricity, maybe in the form of fuel cell vehicles, will be the dominant route to decarbonise light duty transport and passenger cars.

Industry

In industrial applications the challenges for decarbonisation are considerable due to the high temperature heat required for various processes. Approximately half of industrial heat consumption goes to medium and high temperature (>200ºC) heating. Industry has limited technically feasible electric solutions for some (high temperature) processes, with most studies pointing towards electric arc furnace heating. High temperature electric heat pumps are being developed but it is uncertain when these technologies will reach maturity and at what costs they could be implemented.

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[44] We assume nuclear power is not an option in the long term, due to the high cost, especially when running at low capacity factors. Most of the present nuclear capacity in the EU will be out of service by 2050, and not a lot of new capacity is being built.

[45] http://www.emoss.nl/en/electric-vehicles/full-electric-truck/

[46] https://nikolamotor.com/motor

[47] Biodiesel is produced from vegetable oils and waste oils, which scale-up potential is limited given that the use of oil crops as feedstock is being capped in the REDII. Biomethane as a basis for bio-LNG and bio-CNG can be produced from a wider variety of feedstocks. To be able to fully decarbonize transport we foresee a role for both biofuels and renewable gas in heavy transport.

The industry sector currently gets most of its heating through combustion of fossil fuels and to a lesser extent biomass. The most feasible way to decarbonise, in addition to on site or near site production of hydrogen, is through the increased use of bioenergy, including renewable and low carbon gas.

4.1.1 Allocation of renewable gas to the sectors

To allocate the available volume of renewable gas to the various sectors, we start with the B2DS scenario of the IEA that estimates the use of gas in a zero-emission energy system. This assumes a consumption of 45 bcm of natural gas by the industry sector in 2050. In our scenario we allocate 45 bcm of renewable gas to industry to ensure that the industry sector will be decarbonised. The associated cost savings of using this gas are not modelled in this study, although we anticipate that large societal cost savings are associated with this use. Remaining renewable gas potential is mostly allocated to the buildings and electricity generation sectors, where the highest societal cost savings were expected. A quantity of 5 bcm of biomethane is reserved for heavy duty transport, as an alternative to biofuels. A cost comparison between biomethane and biofuel is included in section 4.3. The figure illustrates the allocation of renewable gas are allocated to various sectors.

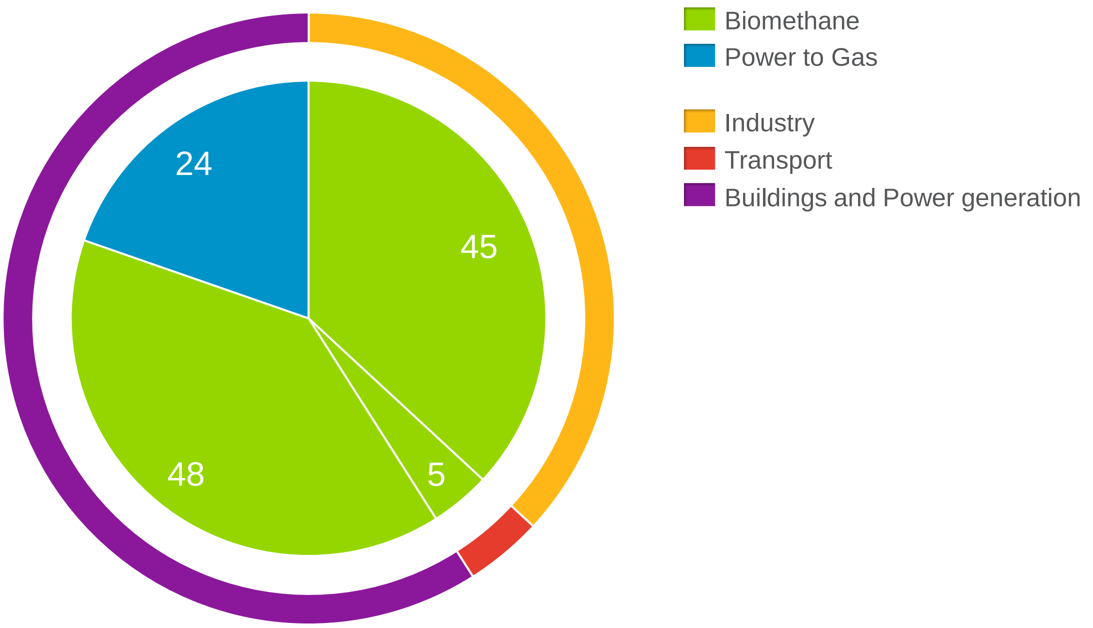

Figure 8 Allocation of renewable energy over various sectors in billion cubic metres of gas

4.2 Quantification of the value of gas in the buildings and electricity sectors

Making a choice between electrification or continuing gas usage implies changing the current energy system in one way or another. For policy makers, it is essential to understand how these changes could influence the future energy system and what the associated societal costs could be. Our quantification of the societal *value*[48] of renewable and low carbon gas can be used to support political decisions on future energy policies. Finding the optimal mix between electricity and gas is particularly difficult when looking at the buildings and power production sectors. For this reason, they are a main focus of the quantification. The estimation of value looks at the optimal use of gas in these sectors in 2050.

To estimate the value in these sectors, two energy scenarios have been modelled in this study. Both scenarios assume a greenhouse gas emission reduction of 95% (as compared to 1990 emissions). One scenario assumes renewable and low carbon gas can be used as an energy carrier in the EU energy system by 2050 ("electricity with renewable gas" scenario), compared to a scenario where gas plays no role in buildings ("electricity only" scenario). Subsequently we compare these two scenarios. The value of renewable and low carbon gas is then defined as the potential cost savings to be achieved when EU policy makers pursue an electricity with renewable gas scenario instead of an electricity only scenario. The scenarios focus on the buildings sector.

The figure below gives an overview of the main cost components which differ between the scenarios. In the following sections, these will be discussed in more detail.

	Electricity only	Electricity with renewable gas
Space heating & insulation	Costs for heat pumps and low-temperature delivery Costs for renovations to extremely high level	Costs for combination of heat pumps and gas boilers Costs for renovations to high level
Transmission & distribution	Costs of maintaining and expanding the electricity grid No costs for gas grid	Costs of maintaining and (to a lesser extent) expanding the electricity grid Costs of maintaining the gas grid
Electricity production	(CAPEX and OPEX) for required wind, solar, and biomass generation	(CAPEX and OPEX) for required wind, solar, biomass and renewable gas generation
Storage	Costs of non-gas storage	Costs of gas storage
+		
Total costs	**Electrification**	**Electrification with gas**

Figure 9 Main cost component differentiation between two scenarios

[48] We define 'societal costs' as the total financial costs for society of the energy transition. The societal value of renewable and low carbon gas are the cost savings that can be realised by including these energy carriers in the overall energy system.

In the following sections, all costs are calculated on an annual basis (using an annuity factor) for the EU-28. The outcome reflects the overall annual costs in 2050, including operational and capital costs. The value is expressed in 2017 euros. The annuities are calculated based on a WACC of 5%.[49]

4.2.1 Space heating and insulation

Decarbonisation of space heating requires major changes in the energy system. A comfortable temperature of 20°C has become the expected standard of living for developed countries. The challenge is to decarbonise the energy system while maintaining this comfort level in all circumstances. There are several solutions.

District heating can provide waste heat, geothermal heat or renewable heat from heat pumps or biogenic sources to homes and buildings in densely populated areas. However, this is not a solution for areas where renewable sources are not available, as heat cannot be transported over long distances, like electricity and gas.

Another solution is to provide space heating with **all-electric heat pumps**. There are two types of all-electric heat pumps available: electric air-source heat pumps (ASHPs) and ground-source heat pumps (GSHPs). Electric heat pumps work in the same way as a refrigerator, transferring heat from one space to another by using electricity. The heat pump absorbs heat from outside and transfers it to the space that needs heating. The difference between ASHPs and GSHPs is that ASHPs absorb the heat from outside air while GSHPs absorb the heat from the ground. GSHPs have better performance at ambient temperatures below zero than ASHPs, but they are significantly more expensive. Heat pumps can be both a space heater and cooler.

Generally, all-electric heat pumps are more efficient than conventional electric heating and gas boilers. ASHPs allow the harvesting of ambient heat even in circumstances where the ambient temperature is lower than the indoor temperature. The ratio between the energy that can be harvested and the electricity required is called the Coefficient of Performance (COP). In cold spells the COP of ASHPs goes down significantly[50] because of the larger difference between source temperature and heating system temperature. This negatively affects their efficiency. Unfortunately, this means that peak heat demand coincides with low efficiencies, causing high demand for electricity. While this does not occur often, the overall system must be designed to accommodate them to prevent loss of load in periods of cold weather.

To achieve high performance, all-electric heat pumps require low temperature heating, meaning that the buildings will need to be well insulated, and that their heat delivery systems will need to be replaced in many cases. The necessary renovation of existing buildings requires a large effort with high impact on residents and owners. The required renovation for using all-electric heat pumps is referred to as **deep renovation**.

Renewable gas allows zero-emission use of gas boilers, gas-fired heat pumps and hybrid heat pumps. **Gas boilers** are ubiquitous in the current energy system, using a significant amount of natural gas.

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[49] Required investments will be partly done by governments, partly by households and partly by private investors. The level of the WACC reflects this. It takes into account inflation (around 2%) plus costs against which governments can borrow (0-3%), a household mortgage interest rate of 4-5%, as well as a higher return on capital provided by the private sector.
[50] As low as 1 with temperatures of -15 degrees Celsius.

As renewable gas will be scarcer than natural gas, it is not feasible to use them for all of the heat demand in the long-term as volumes are significant.

Gas-fired heat pumps would reduce demand for gas by using ambient heat, but in our estimation the remaining demand for gas would be too high to be met with renewable gas. Gas-fired heating requires less rigorous insulation as the gas heaters are better suited to meet peak demand. In this report, the required renovation for gas-fired heating is referred to as **less deep renovation.**

Gas-fired heat pumps versus hybrid heat pumps

Gas-fired heat pumps are being developed as a heating solution which reduces gas demand while avoiding expensive building adjustments and electricity peak supply problems. To make a choice between the technologies, we carried out a short comparison between gas-fired heat pumps and hybrid heat pumps. To gain some insight, we compared the volume of gas required for installing either hybrid heat pumps or gas-fired heat pumps in one-sixth of all households and commercial buildings.

Hybrid heat pumps are designed in such a way that the air-source heat pump serves as baseload and covers the heat demand up to 40% of the yearly peak. The remaining peaks are covered by a gas boiler. For the course of a year, that results in 231 TWh heat that is covered by the heat pump and around 106 TWh of heat that is covered by the gas boiler. Assuming an energy efficiency of close to 100% for the gas boiler and the hourly COPs for air-source heat pumps, the electricity demand of hybrid heat pumps in Europe would amount to 98 TWh per year. In many hours, the heat pump has to operate in sub-optimal conditions in which the COP is around 1 to 2. Additionally, as the heat pump usually performs worse in hours with a particularly high heat demand and better in hours with a low heat demand, the overall yearly performance of the heat pump is worse than an average hourly COP would indicate. The gas demand would be around 10 bcm. Assuming renewable gas costs of €52/MWh and electricity costs of €84/MWh, which result from our analysis, the heating costs using hybrid heat pumps would be around €13.7 bn.

Gas-fired heat pumps can be absorption and endothermic heat pumps. COPs of endothermic pumps range between 1.3 and 1.8 while absorption heat pumps range between 1.2 and 1.4[51]. Given an optimistic COP of 1.8, replacing all hybrid heat pumps with gas-fired heat pumps would result in a gas demand of 17.6 bcm and gas costs of around €8.4 bn. Excluding the technology costs, an additional use of 7.6 bcm of gas would result in around €4.0 bn savings.

However, the scenario analysis shows savings of nearly €20 bn could be achieved by increasing the usage of gas in the heating sector by 10 bcm through increasing the share of hybrid heat pumps to 37%, replacing full-electric air-source and ground-source heat pumps. Therefore, it can be concluded that even though the energy savings of gas-fired heat pumps are considerable, there is more added value in renewable gas if it used to lower system costs by replacing air-sourced and ground-sourced heat pumps and distributing the limited available renewable gas volume among more buildings.

Hybrid heat pumps are the most promising alternative for all-electric heat pumps. A hybrid heat pump is a relatively small electric heat pump with a gas boiler to meet peak demand. The gas boiler is deployed in the few occurrences where peak supply is required. It is assumed that the electric heat pump is an air-source heat pump with a

[51] Gas Heat Pumps. Efficient heating and cooling with natural gas. GasTerra.

comparable performance and the same COPs as the all-electric air-source heat pumps. The advantages of hybrid heat pumps are:

- They can make use of the existing gas infrastructure in the buildings sector, reducing the required expansion of electricity grids;
- They can deliver heat using the existing heat delivery systems, avoiding replacement of existing heat delivery systems;
- They require less deep renovation as they can deliver peak demand efficiently and at limited additional cost (see also Figure 10);
- The equipment is relatively low cost, because expensive heat pump capacity is replaced with low cost gas boiler capacity;
- Because of the usage of existing networks and the requirement of less deep renovation, the introduction of hybrid heat pumps can occur much faster than other techniques to reduce CO_2;
- Hybrid heat pumps allow for somewhat lower insulation levels, limiting heat entrapment in the summer and thereby avoiding increasing demand for cooling.

The figure illustrates electricity demand of an all-electric and a hybrid heat pump. It shows that peak electricity demand is substantially lower for the hybrid heat pump. The troughs are explained by the COP changes that take place as the weather changes. These are not directly linked to heat demand for the home.

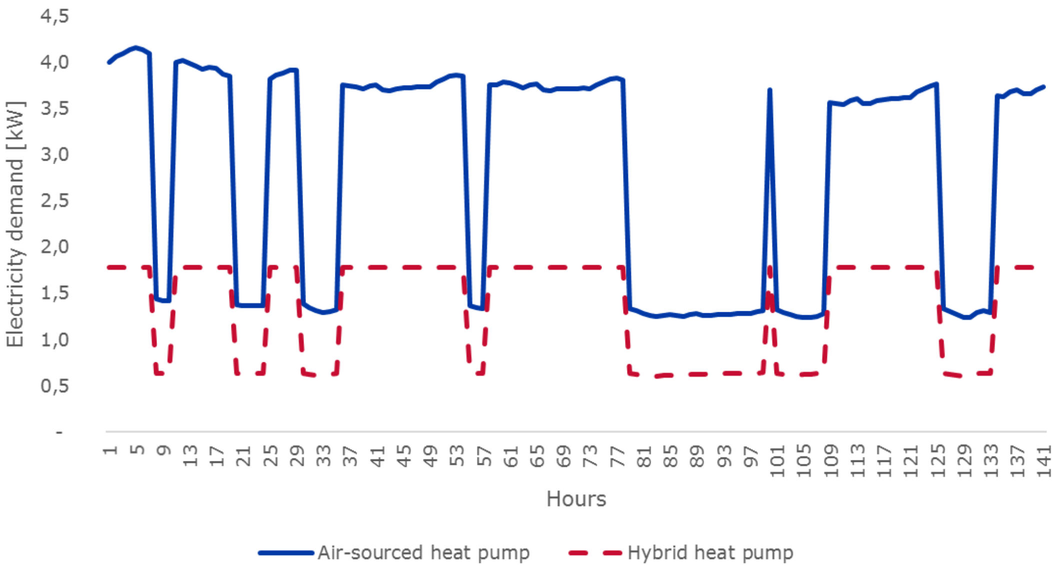

Figure 10 An illustrative profile for power demand of heat pumps of a single-family home in Western Europe

Modelling approach in the building sector

The impact of space heating on the energy system is largely determined by the heating equipment used, the local climate characteristics and the characteristics of the buildings. Particularly the insulation level of the buildings strongly affects the heat loss during cold weather and therefore the heat demand. In our modelling, the building stock and thereby the energy consumption for heating is differentiated in five geographical regions throughout Europe.

To compare the costs in the building sector between the two scenarios that were modelled (as discussed in section 0) we applied the following assumptions. In the electricity only scenario, most households are heated with ASHPs (60%) and GSHPs (20%). In the electricity with renewable gas scenario, this is done with ASHPs (29%), GSHPs (14%) and hybrid heat pumps (37%). The amount of hybrid heat pumps is restricted by the existing connections to the gas grid. In both scenarios, we assume the remaining 20% of buildings are supplied with district heating.

The chosen insulation level of a building is connected to the heating technology chosen. Extreme insulation is required for the households with electric heat pumps, while medium insulation is sufficient for district heating and gas-fired heating technologies. Existing buildings need to undergo deep renovation to reach high insulation. Medium insulation can be accomplished with less deep renovation. The Annex provides a more detailed description of the assumptions behind the building stock distribution and renovation levels. Table 4 shows the range of insulation costs between medium to high levels of insulation.

Table 4 Overview of the range of annual insulation cost depending on the renovation level per region and building type (Ecofys, 2012: Renovation Tracks for Europe up to 2050. Building renovation in Europe- what are the choices?)

Region	Building	**Annual costs related to insulation** (€1000 per building)
Northern Europe	Single-family home[52]	2.9 – 4.2
	Multi-family home[53]	42.0 – 58.9
	Commercial building	21.7 – 30.5
Western Europe	Single-family home	1.0 – 1.4
	Multi-family home	13.8 – 19.8
	Commercial building	7.2 – 10.2
Southern Europe	Single-family home	1.0 – 1.2
	Multi-family home	13.5 – 17.5
	Commercial building	7.0 – 9.1
North-East Europe	Single-family home	0.5 – 0.6
	Multi-family home	6.1 – 7.8
	Commercial building	4.3 – 5.4
South-East Europe	Single-family home	0.6 – 0.8
	Multi-family home	11.0 – 14.1
	Commercial building	4.5 – 5.8

Including renewable gas in the building sector has significant value

Full electrification of space heating will lead to higher costs related to buildings, due to high insulation and heating technology costs. A small share of gas-fired boilers and hybrid heat pumps already has the potential to save up to €52 billion per year (excluding infrastructure costs). The table below gives an overview of the potential savings connected to the buildings sector.

[52] Living area per building type:
Single-family home: 125 m² for all areas
Multi-family home: 3811 m² for NO, WE, SO, 2825 m² for NE and 4796 m² for SE
Commercial building: 1972 m² for all areas
[53] About 40 homes

The highest savings occur through lower insulation costs as hybrid heat pumps do not necessarily require deep insulation. However, the lower insulation level results in a slightly higher energy demand. The higher energy demand and lower efficiencies of hybrid heat pumps compared to air- and ground-sourced heat pumps therefore leads to slightly higher energy costs in the electricity with renewable gas scenario.

Table 5 Potential savings through replacing air-sourced and ground-sourced heat pumps with hybrid heat pumps. Figures are annual costs and cost difference by 2050 for the 'no gas' and 'with gas' scenarios (rounded)

Costs for	'no gas' (bn. €)	'with gas' (bn. €)	Annual savings (bn. €)
Heating technologies	210	173	37
Insulation	180	159	21
Energy use for heating	61	67	-6
Total buildings	**451**	**399**	**52**

Note: this calculation omits the benefit of renewables gases as a quick conversion method for the building sector in the EU. After all, insulation of all buildings in the EU, required for a switch to all-electric solutions, will require several decades. The same applies for building heat networks. On the other hand, installation of e.g. hybrid heat pumps can be carried out (like smart metres) in just 5-10 years for all gas-connected buildings in the EU.

4.2.2 Transmission & distribution

Reliable electricity infrastructure is essential for a power system to work. The electricity grid must at all times ensure sufficient capacity is available to match demand and supply. There are two main levels in the electricity grid, the distribution grid and the transmission grid (with its medium and high voltage grids). Households and decentralised generation are connected to the distribution grid. Large (industrial) consumers and power plants are connected to the transmission grid. The grids must be dimensioned to meet peak transportation and distribution needs. The figure below illustrates the main components of the electricity grid.

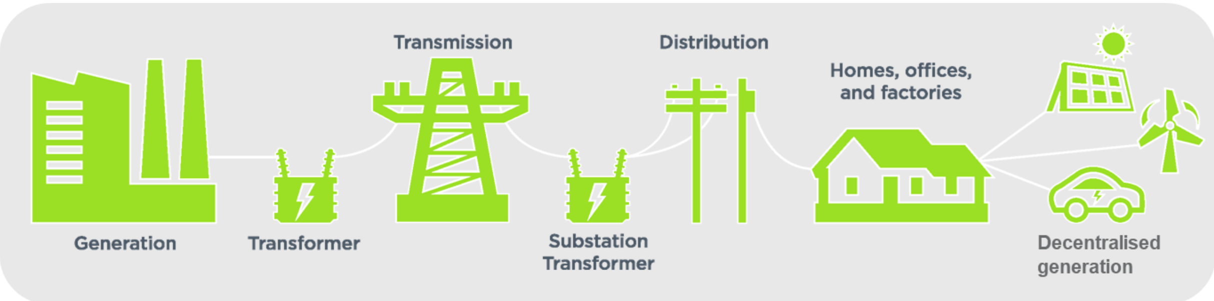

Figure 11 Power system components

The electricity grid is designed to match power demand and supply at any time. Electrification in buildings and mobility will cause an increase in electricity volume but also in peak demand. Meanwhile, more decentralised generation, such as rooftop solar PV, is being introduced. These changes all impact the distribution grid, which will need to be upgraded to facilitate higher peak demand.

The current average distribution grid capacity in the EU is about 1 kW per household. This is expected to grow to 3-5 kW in 2050 if heat and other energy consumption is electrified.

Due to high electrification, the total electricity demand, and thereby the potential for renewable electricity, increases. Much of this will be generated in large wind and solar farms often far from the high demand regions (i.e. cities). Higher transmission capacity will therefore be necessary to transport the generated electricity to the place of demand.

The current gas infrastructure can alleviate this effort. The existing gas infrastructure has a remaining lifetime until after 2050, meaning a low level of investment is needed. In a scenario including renewable gas, energy can also be transported via the gas infrastructure. Moreover, the electricity demand from buildings, and thereby the total demand, is lower in a scenario where hybrid heat pumps provide peak generation using renewable gas (see section 4.2.1). This reduces peak demand on the electricity grid both at distribution and transmission levels, and avoids the need for costly electricity infrastructure upgrades.

To calculate the costs for upgrading the electricity infrastructure, we apply different approaches for high voltage, medium voltage and low voltage grids.

High voltage

The necessary reinforcement of the transmission grid depends on a wide range of factors, among them the location of energy production means, the volatility of energy supply and demand and the type of cables used (e.g. overhead cables vs. underground cables). The first two factors are influenced by the energy scenario choice (i.e. renewable electricity production, demand profiles), the details of which will be explained in the next section. However, the acceptance of new overhead lines or the preference for underground cables influences investments in both scenarios.

"The use of power-to-gas allows useful exploitation of excess renewable generation capacity."

The e-Highway 2050 project calculated the necessary investments into the pan-European transmission grid for different scenarios[54]. The study focused mainly on the requirements for bulk capacities between different clusters within the EU. The "100% RES" scenario of the e-Highway study includes high levels of electrification across the EU. These are the costs we assume to be applicable in the electricity only scenario. For the scenario in which gas plays a role, a lower electrification in the building sector is partly offset by lower renovation levels in the building sector.

The resulting power demand, peak load and amount of installed renewable energy generation is comparable to the electricity only scenario. However, in the electricity with renewable gas scenario the electricity transmission costs are expected to be lower than in the electrification only scenario mainly for two reasons. Firstly, as the transport of solid biomass is costlier than of biomethane, power plants that run on biomass will be built closer to ports and rivers and

[54] www.e-highway2050.eu/e-highway2050/

further from demand. In contrast, power plants running on biomethane can be more distributed and located more closely to areas with a high demand for electricity demand.
Secondly, the use of Power-to-Gas allows useful exploitation of excess renewable generation capacity and generation capacity in remote areas. Instead of the construction of expensive transmission lines, the existing gas grid can be used for transporting the energy. Therefore, in the electricity with renewable gas scenario, the “Small & local” scenario is used to estimate the electricity transmission costs[55].

Medium voltage

To calculate the cost for medium voltage grid reinforcements, it is assumed that the costs depend on peak demand and on the costs per capacity unit for different locations (urban/intermediate/rural areas). These annual medium voltage grid reinforcement costs vary between €21/kW for urban areas and €57/kW[56] for rural areas. The average costs per capacity unit were calculated based on the trend of population growth and the distribution of the population within urban, intermediate and rural areas. The peak demands are based on the profiles as created in the modelling for buildings (as explained in section 4.2.1). Full electrification increases peak electricity demands, meaning higher transport capacity is required.

On the medium voltage level, an indication of the average cost for additional grid capacity is available for the urban, suburban, and rural areas from a previous Ecofys study on the value of congestion management in the Netherlands.[56] The current study used these costs as a simplification for the Europe-wide electricity grid extension cost. The average medium voltage electricity costs are calculated based on the expected density of the European network in 2050.

Low voltage

The costs for upgrading the distribution grid can only be partly allocated to full electrification of space heating. We assume that in the “electricity only” and the “electricity with renewable gas” scenarios there will be similar levels of electrification for mobility and for decentralised power generation. Due to the additional demand from electric vehicles and local surpluses from solar PV, it is likely that refurbishment of low voltage grids will be necessary, regardless of the level of implementation of heat pumps.

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[55] Because CAPEX estimates for the transmission grid in the literature are not robust and vary largely by region, transmission line, cable length and technology, the transmission costs were approximated with the cost estimates provided by the e-Highway study. The e-Highway study provides only indicative numbers as it partly over- and partly underestimates the required costs in the transmission grid.
On the one hand, the study underestimates the necessary investments into the transmission grid as it does not take into account the investment requirements within countries at transmission level. While many countries seek to be (close to) self-sufficient and would therefore prefer more local even though inefficient energy systems, this study assumes a rather optimised energy system which is in line with the European vision of an Energy Union and a pan-European electricity network.
The e-Highway study also excludes investments that have to be done by 2040 anyway independently from the scenario chosen. This leads to overall lower estimates for investments in the transmission grid but leaves the cost comparison between different scenarios unaffected.
On the other hand, the two e-Highway scenarios “100% RES” and “Small & local” are contrasting scenarios. While the former expects PV in North Africa and offshore wind in remote areas, the latter expects that considerable amounts of the electricity demand can be covered at local level (residential PV). By using the “Small & local” scenario in the electricity with renewable gas scenario the transmission costs are probably underestimated given the fact that the amount of renewable generation installed is approximately the same in the electricity only and electricity with renewable gas scenario.
In this study, the reinforcement of the high voltage transmission grid is based on the medium scenario of the e-Highway project. It is assumed that the use of overhead lines is slightly limited, but still possible. Also, it is assumed that the difference in peak capacity which results from a different share in electric heat pumps leads to additional capacity reinforcements of the grid. The necessary investments would therefore follow the medium scenario in the e-Highway 2050 cost predictions. Following other studies for the European Commission (Ecofys, 2017, Investment Needs in Trans-European Energy Infrastructure up to 2030 and beyond) OPEX for the grid was left out from the analysis. These costs are relatively small and very variable.
[56] Ecofys, 2016. Waarde van congestiemanagement (available in Dutch).

The electricity grid operator's approach when refurbishing is generally to put generous overcapacity down, as the marginal costs per kW are very small compared to the overall costs of refurbishment. This means that a refurbished low voltage grid can often accommodate additional demand from electric heat pumps. Therefore, additional costs for infrastructure upgrades cannot be fully allocated to electric heat pumps. To reflect this dynamic, this study allocated 50% of the one-off costs for expanding low voltage grid to electric heat pumps.

Gas infrastructure

In the electricity with renewable gas scenario, the gas infrastructure will be kept in place. As the lifetime of the existing gas infrastructure is estimated to be at least another 50 years[57], it is assumed no investments are needed. This means investment costs in both scenarios are equal. There are operational costs related to maintaining the gas infrastructure and replacing parts that have a shorter lifespan, like compressors. These costs are included only in the electricity with renewable gas scenario.

An investment that is required for enabling the gas infrastructure for renewable gas is the collection infrastructure from biomethane production sites. These include additional compressors and pipelines to feed biomethane from distribution grids into the transmission grids. These are included in the scenario with renewable gas. Detailed assumptions can be found in the Annex.

Including renewable and low carbon gas has value for infrastructure

The costs of maintaining the gas infrastructure are more than offset by the investment costs avoided in the electricity grid. It should be noted that this is based on our conservative estimate for biomethane production. It is likely that the real potential is higher, and there are other sources of renewable gas. While such additional volumes do not increase the cost of maintaining the infrastructure, they would allow additional savings in the electricity system.

Table 6 Potential savings in the gas and electricity infrastructure. Figures are annual costs and cost difference by 2050 for the 'no gas' and 'with gas' scenarios (rounded)

Costs for	'no gas' (bn. €)	'with gas' (bn. €)	Cost difference (bn. €)
Gas infrastructure	20	24	-4
Electricity distribution infrastructure	31	30	1
Electricity transmission infrastructure	70	65	5
Total infrastructure savings	**121**	**119**	**2**

4.2.3 Electricity production

Electrification of heat will require a significant increase in the production of electricity. At the same time, all production of electricity must decarbonise. This means there will be fundamental changes in the production of electricity. This section will briefly describe the considerations around electricity production in a decarbonised system, followed by the assessment of the value of using renewable and low carbon gas.

[57] Generally accepted by accountants and regulators (Gasunie annual report 2016). This is an indication of the financial amortization rate.

The most viable renewable electricity sources, wind and solar, are intermittent i.e. weather-dependent for their production. Meanwhile, electricity demand also varies in time. This will further increase if the heating and the transport sectors are electrified.

The difference between the intermittent renewable electricity production and the demand is called the residual load. If the intermittent electricity production is not sufficient to cover the power demand, additional electricity sources will be required (so-called dispatchable generation capacity). At other times, renewable electricity production will be higher than the power demand and the "surplus electricity" must be either stored or curtailed.

We model the behaviour of the future power system through the following steps. To start, we estimate a viable capacity of wind and solar capacity. We set the capacity to meet 85%[58] of the yearly electricity demand in both scenarios. Both renewable power generation and electricity demand are constructed from hourly profiles of an average year in Europe. The hourly difference results in the residual load profile.

The table below gives the general assumptions behind the electricity generation and demand analysis in this study.

Table 7 Electricity technology cost assumptions used in this study

	Electricity without gas	Electricity combined with gas
Demand	• Base demand profile is based on the 2015 EU demand profile extrapolated according to EU population growth forecasts towards 2050 (7%). • Electric mobility and space heating demand are added to demand profiles. • **80%** of space heating is based on electricity. • Space heating profiles have been calculated per region based on local climatology. • Typical load profile of single electric vehicle (EV) with congestion management is extrapolated to expected number of EVs in 2050. • **No change in demand due to changing consumption patterns (e.g. increasing digitalisation) or efficiency improvements were taken into account.**	• Base demand profile is based on the 2015 EU demand profile extrapolated according to EU population growth forecasts towards 2050 (7%). • Electric mobility and space heating demand is added to demand profiles. • **65%** of space heating is based on electricity. • Space heating profiles have been calculated per region based on local climatology. • Typical load profile of single EV with congestion management is extrapolated to expected number of EVs in 2050.
Generation	• Gas generation is **not** possible. • Renewable energy sources (RES) cover 85% of the total power consumption. • RES profiles based on the wind (onshore and offshore), solar and hydro power generation profiles for NW Europe[58]. • RES generation is scaled according to the required demand volume.	• Gas generation is possible. • Renewable energy sources (RES) cover 85% of the total power consumption. • RES profiles based on the wind (onshore and offshore), solar and hydro power generation profiles for NW Europe58**.** • RES generation is scaled according to the required demand volume.

[58] Ecofys, 2017. Translate COP21: 2045 Outlook and implications for offshore wind in the North Seas.

The role of batteries and Power-to-Gas

Besides pumped hydro, our modelling assumes the use of batteries and Power-to-Gas. An advantage of Power-to-Gas over batteries is that hydrogen or renewable gas can be stored significantly more cheaply (up to a factor 1000) than electricity. A disadvantage of Power-to-Gas is the efficiency losses in the cycle of Power-to-Gas-to-electricity when used for power generation, which are high on a short-term basis compared to the cycle with battery storage (battery losses over longer periods can be very significant too). These two characteristics mean that battery storage is well-suited for short term storage, while "Power-to-Gas-to-Storage-to-Power" is well-suited for long-term storage. Besides, stored gas can be used at a time when it has the highest marginal value over a period of several months. A well-designed energy system would mitigate the disadvantage of converting gas to power by using it directly in gas appliances.

The electricity only scenario does not include any gas infrastructure, meaning Power-to-Gas-to-Storage-to-Power is not an option. This limits the options for storing surplus electricity. In addition to pumped hydro, high capacities of expensive battery storage are then needed to keep curtailment to a minimum. It is not deemed viable to use batteries for seasonal storage due to the high costs of storage. Seasonal "storage" in an electricity only scenario will be supplied by bioenergy using expensive solid biomass back-up plants.

In our model, we apply battery storage where economically viable for short term balancing – within the limitations of battery storage capacity. There will be a moment where they are fully charged (in case of surplus electricity) or fully discharged (in case of residual load). The hourly residual load or electricity surplus can be higher than the battery storage volume. Battery storage is applied in all scenarios even if Power-to-Gas is available. While Power-to-Gas is very suitable for long-term balancing, battery storage is regarded as a low cost option when no spinning reserve[59] is available. Therefore, in order to avoid must-run capacities of gas generation, a small amount of battery storage was considered even in combination with Power-to-Gas.

The profile that remains is to be supplied with dispatchable power in case there is residual demand, or, if there is electricity surplus, can be used for producing renewable hydrogen.

Subsequently, the electricity surplus that remains after using battery storage is either used for renewable hydrogen or curtailed as a last resort. If a residual load remains after battery storage, dispatchable generation is needed to produce this power. Figure 12 gives a schematic overview of the steps as described above.

[59] Very flexible power generation based on standby (running) power plants (often gas fired).

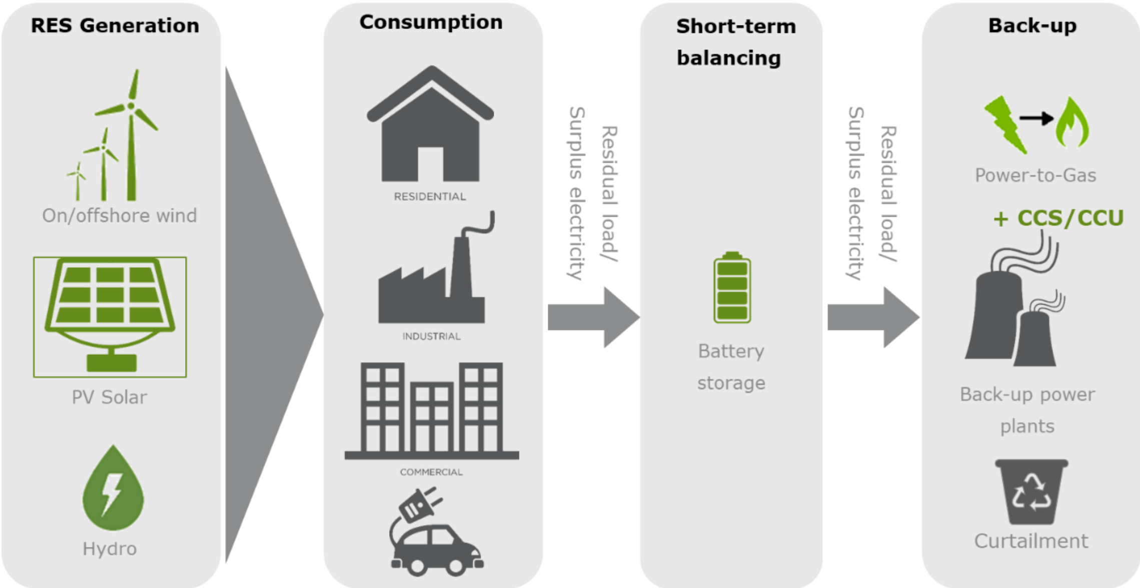

Figure 12 Schematic overview of energy production modelling

Electricity cost model

To estimate the costs related to meeting residual demand with dispatchable electricity generation, we developed an electricity cost model. This model uses the fixed and variable generation costs to calculate the lowest cost combination of generation technologies to provide the required electricity at all times. The possible dispatchable generation technologies are biomass back-up plants, Open Cycle Gas Turbines (OCGT) and Combined Cycle Gas Turbines (CCGT) with the option to include CCS in case of natural gas combustion. It results in a set of required installed capacities per technologies and their related costs for capital and operational expenditures. Table 8 shows the technology cost assumptions used in this study.

Table 8 Technology cost assumptions used in this study

Technology	CAPEX	Fixed OPEX	Variable OPEX	Cost of fuel	Efficiency	Load factor	Lifetime
Unit	€/MW	€/MW/a	€/MWh	€/MWh			Years
Gas CCGT	750,000	11,250	2.7	52	60%	n/a[60]	30
Gas OCGT	300,000	7,500	2.7	52	40%		30
Gas OCGT with CCS	880,000	15,000	2.7	52	34%		30
Gas CCGT with CCS	1,500,000	22,500	2.7	52	51%		30
PV	893,000[61]	8,935	0	0	n/a	12%	30
Wind onshore	1,195,000	24,443	0	0	n/a	35%	25
Wind offshore	2,400,000	92,500	0	0	n/a	45%	25
Hydro	1,700,000	7,500	0	0	n/a	35%	50
Solid biomass	2,450,000	17,150	9	29	35%	n/a	30
Battery storage costs	n/a[62]	0	0	0	90%	n/a	5
Power-to-hydrogen	640,000	0	0	0	86%	n/a	30

To explain the logic behind the electricity cost model, the figure below shows an example of the residual load curve for different technologies in the scenario with renewable gas. In this example, the renewable gas volume is 122 bcm. As we can see, from an economic point of view, using renewable gas with OCGT and CCGT to supply the peak load is the most viable option. Even though using solid biomass plants is never the most economic option, due to the limited volume of gas in the system, biomass is used to cover the remaining residual demand. We also see that when there is electricity surplus, the model will first allocate this to renewable hydrogen production. Curtailment of electricity is only used as a last resort.

[60] The load factors for dispatchable technologies are not an input, but a result from the modelling.

[61] As the capacities will be installed between now and 2050, these costs represent the average costs between now and 2050. Significant cost reductions are expected for wind and solar energy towards 2050, hence their corresponding costs have been taken as the average between now and forecasted cost for 2050.

[62] Expressed in capacity price per MWh of storage capacity: 80,000 €/MWh.

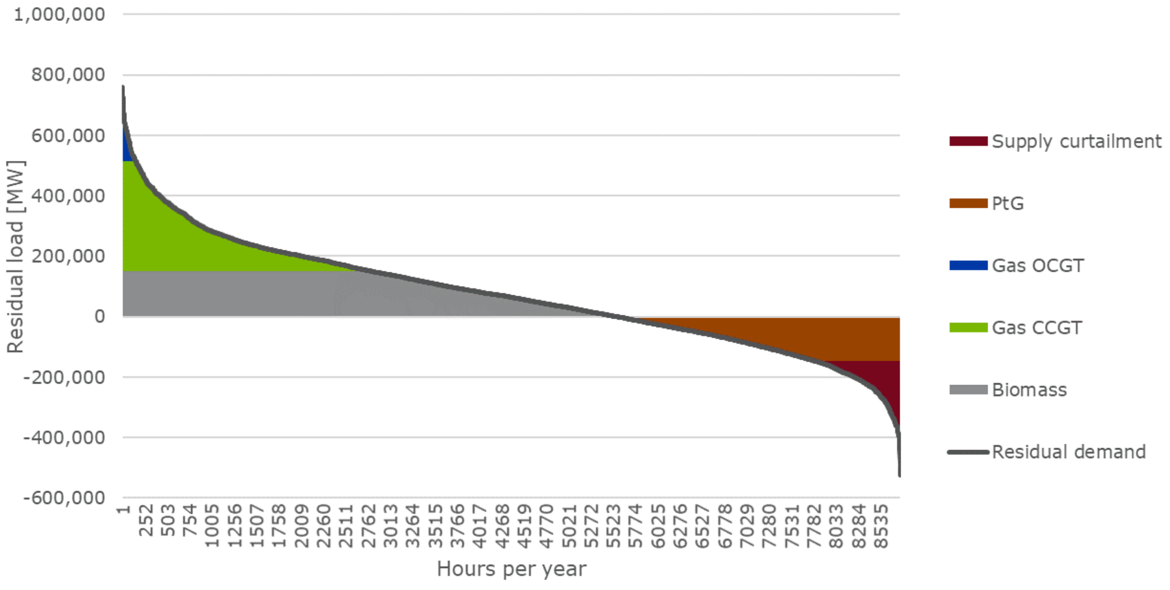

Figure 13 Example of residual load curve in scenario with renewable gas

To estimate the value of renewable gas in electricity production, we compare the overall generation costs of the electricity only and electricity with renewable gas scenarios. These scenarios differ in the following ways:

In the electricity only scenario, the overall electricity demand from buildings is close to the scenario with renewable gas. However, due to full electrification, the peak demand is higher. This has an impact on the required dispatchable generation.

Additionally, excluding gas from the generation mix in the electricity only scenario leaves as most viable options for covering residual load batteries, hydro and solid biomass generation. This has an impact on the capital and operational expenditure that is related to power generation.

Scenario with renewable gas results in lower costs for power production

The result of the analysis shows that in a scenario with renewable gas, the power demand is roughly the same due to the higher share of less deep renovated buildings with hybrid heat pumps. This requires a similar amount of renewable electricity capacity to be installed.

Having the possibility to use renewable gas for generation instead of solid biomass is an advantage.

“Choosing an energy system where gas is still used will be significantly cheaper than an energy system based only on electricity.”

As Figure 14 and Figure 15 show, the residual load in the electricity with renewable gas scenario can be covered through a combination of renewable hydrogen production, OCGT and CCGT powered with renewable gas or low carbon gas. These options are all much cheaper than using solid biomass and make better use of the existing gas and electricity infrastructure. As there is a limited volume of renewable gas, some biomass generation is required also in the electricity with renewable gas scenario.

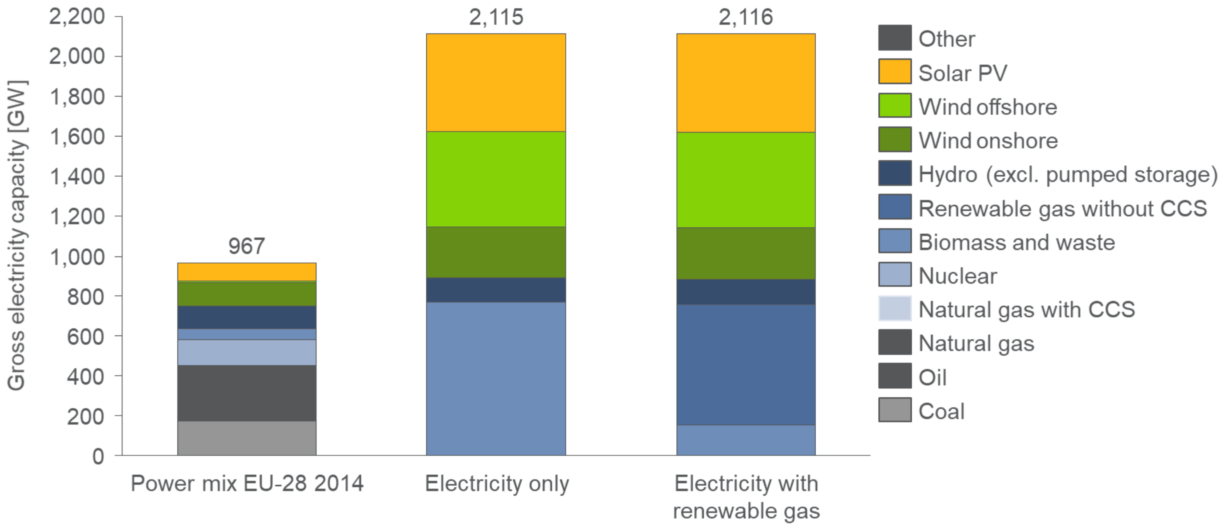

Figure 14: Power mix in both scenarios compared to EU-28 power mix in 2014

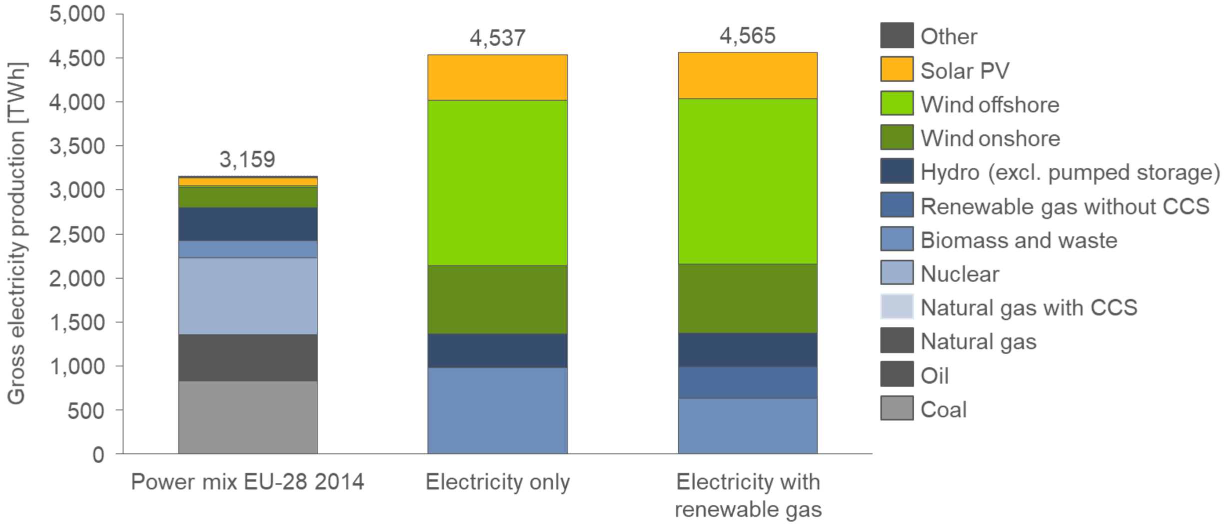

Figure 15 Electricity generation mix in both scenarios compared to EU-28 power mix in 2014

The electricity production modelling shows that significant cost savings can be realised if a scenario which allows gas usage is chosen. Both scenarios will require significant investments towards 2050. However, choosing an energy system where gas is still used will be significantly cheaper than an energy system based only on electricity. The model shows that annual cost savings in 2050 reach up to €84 billion, equalling on average €370 per European household. Table 9 gives an overview of the results. Figures are annual savings in 2050[63].

Table 9 Potential savings in the gas and electricity production. Figures are annual costs and cost difference by 2050 for the 'no gas' and 'with gas' scenarios (rounded)

Costs for	**'no gas'** (bn. €)	**'with gas'** (bn. €)	Cost difference (bn. €)
Electricity production	386	302	84
Total	**386**	**302**	**84**

4.2.4 Summary

The results above show that there is a cost saving potential if renewable and low carbon gas is included in the buildings and power sector in future energy scenarios. When adding the potential for renewable hydrogen, the annual savings increase to €138 billion, as more homes can be heated with hybrid heat pumps and less solid biomass back-up capacity is required. The table below gives a breakdown of where savings are achieved.

[63] The electricity production costs also include the profile costs (value of electricity at different moments in time). A major driver for profile costs is the reduced utilisation of capital-intensive plants. Although these costs are often disregarded in the literature, they are significant and are greatly influenced by the penetration rate of wind power. As the investment cost of generation capacity influences the resulting electricity price, the profile costs are taken into account in the cost model. If the penetration of variable renewable power generation increases but a high peak load remains, the cost for the remaining residual load will increase accordingly. Balancing costs (net cost of intra-day trading and imbalance cost, e.g. operation reserve) depend greatly on the quality of power production forecasts and the amount of flexibility in the market. As the balancing costs are relatively small compared to the profile costs, they were not considered in this analysis. This means that the integration costs are underestimated. The grid related costs (price spread across bidding areas) decrease with the reinforcement of the transmission grid and the integration of the European power market. For simplicity, it is assumed that the reinforcement of the transmission grid (the costs of which are explained in section 4.2.2) will lead to negligible grid-related costs of renewables. The OPEX for solar PV and wind are assumed to be zero. Therefore, curtailed power generation from these energy sources does not result in additional OPEX, but does not change the CAPEX either. As in case of curtailment the CAPEX is distributed over fewer hours, the power system becomes more expensive and the curtailment costs are taken into account indirectly.

Table 10 Summary of annual costs and cost difference by 2050 between the 'no gas' and 'with gas' scenarios (rounded) and resulting total annual societal cost savings achieved by using renewable gas in existing EU gas infrastructure

Costs for	Sector	'no gas' (bn. €)	'with gas' (bn. €)	Cost difference (bn. €)
Heating technologies	Building	210	173	37
Insulation	Building	180	159	21
Energy production for heating	Building	61	67	-6
Gas infrastructure cost	Infrastructure	20	24	-4
Electricity distribution infrastructure	Infrastructure	31	30	1
Electricity transmission infrastructure	Infrastructure	70	65	5
Heat infrastructure cost for heating	Infrastructure	37	37	0
Electricity production	Energy	386	302	84
Total		**995**	**857**	**138**

In total, the use of 72 bcm of EU-produced renewable gas to decarbonise the building and power sector results in total savings of €138 bn. This is around 14% less than the system costs for the infrastructure, building and power sector in the 'electricity only' scenario, without any gas.

4.3 Quantification of costs for Heavy Duty Vehicles

To assess the competitiveness of renewable gas in heavy duty transport, a cost comparison was made for small and large trucks[64] using either biodiesel or CNG for small trucks and LNG for large trucks. The following two tables provide an overview of the general assumptions regarding the two types of vehicle and the three types of fuel considered. The number of vehicles is based on the new registrations in 2015 and a vehicle lifetime of 11 years.

Table 11 General assumptions Heavy Duty Transport (Ricardo 2016)[65]

	Unit	Small trucks	Large trucks
Distance travelled	km/a	35,000	60,000
Lifetime	years	11	11
New registrations	'000	326	260
Number of vehicles	'000	3,583	2,861

Existing cost estimates for refuelling stations vary greatly. This is because the costs depend heavily on the utilisation and capacity of the stations. For the purpose of this analysis, the fuel cost estimates are 1,000 €/vehicle/yr for CNG small trucks and 1,200 €/vehicle/yr for LNG large trucks; at the lower end of the cost ranges provided in Table 12. In order to assess whether heavy duty vehicles running on renewable gas could potentially be cost competitive with biodiesel vehicles, a rather optimistic estimate for refuelling station costs for CNG and LNG trucks was chosen.

[64] The analysis includes rigid trucks, meaning trucks with a single frame, not combos with a tractor and a trailer.
[65] The Ricardo study also includes some values for large articulated (meaning tractor and trailer) trucks, but these are assumed to be dual fuel vehicles (operate 65% on methane and 35% on diesel). As such, they are not suitable for a cost comparison between biomethane and biodiesel.

If CNG and LNG trucks are more expensive than the biodiesel alternatives even using optimistic cost assumptions, then biodiesel for heavy duty vehicles appears to be more preferable.

Table 12 Main assumptions regarding heavy duty vehicles by fuel type (Ricardo 2016)

		Small trucks		Large trucks	
Fuel type	**Unit**	**Biodiesel**	**CNG**	**Biodiesel**	**LNG**
Cost per vehicle	€/vehicle	45,000	55,600	73,900	85,400
Refuelling station costs	€/vehicle/y	180	From 847 (low) up to 3,321 (high)	576	From 1,047 (low) up to 4,535 (high)
Energy consumption	MWh/y/vehicle	56.3	75	150.8	202

The costs for biodiesel are based on advanced renewable diesel as fuel. This is a drop-in fuel that can be blended in unlimited shares (up to 100%) with fossil diesel in existing internal combustion engine technology. This fuel is produced from advanced feedstocks including sequential oil crops. We estimate a price for this premium biofuel of €1100/tonne. This is higher than the average cost of conventional FAME (Fatty Acid Methyl Esther) biodiesel, for which prices currently fluctuate between €600/t and €1000/t[66], yet (we assume) lower than the current cost of advanced renewable diesel.

In order to derive the CNG and LNG fuel costs from the biomethane prices, estimates for conversion losses and liquefication expenditures were derived from literature. Prices for bio-CNG are comparable to the price of €52/MWh for biomethane (see section 3.4), divided by an efficiency of 98%[67]. Costs for additional compressor stations and storage tanks were not included. Therefore, the costs for the storage of biodiesel were not included either. For bio-LNG, the OPEX and CAPEX were approximated with €24.3/MWh, based on a study of liquefaction costs for biomethane. While literature suggested an efficiency of 100% for the liquefaction process, around 5% of the energy content of the gas is used during the conversion[68].

Based on the cost estimates for the fuel, vehicles and refuelling infrastructure as well as the number of vehicles and their usage, we calculate the costs for small and large trucks. The biofuel scenario is around €6.4 billion[69] per year (6%) cheaper than the scenario where CNG and LNG are used for heavy duty transport. If the price for biofuels vehicles and gas-fired vehicles become comparable, the renewable gas scenario remains slightly more expensive than the biofuels scenario.

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[66] Prices for biodiesel produced from vegetable oils depend heavily on feedstock costs, which are subject to changing markets and changes in weather conditions. We assume that in the future the role for crop-based FAME will reduce and advanced renewable diesel will be the dominant biofuel.
[67] https://www.nrel.gov/docs/fy16osti/64267.pdf
[68] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/336022/gasesous-fuels-report.pdf
[69] 2017 euros

Table 13 Cost comparison for heavy duty vehicles (own calculations)

Costs for	Biofuels (bn. € per year)	Renewable gas (bn. € per year)
Technology costs	45	53
Refuelling station costs	2	7
Energy costs	68	61
Total	**115**	**121**

The comparison shows that the costs for renewable gas in heavy duty vehicles are a little higher, but comparable. These similar cost levels and the uncertainty around the assumptions indicate that the lowest cost technology will mostly depend on policy and innovation, and that it is likely that biomethane will play a role in a decarbonised transport sector in 2050. Development of markets, costs and regulations will ultimately determine to what extent available biomethane will be allocated to the transport sector.

It is important to note that the analysis above does not include the disadvantages of pollutants including fine particulates from biodiesel transport. Local pollution related to gas transport is very low.

4.4 Other related benefits from using renewable gas

In this section, we highlight the benefits of renewable gas production that have not been quantified. These are related to strengthening the rural economy, synergy with food production and energy security and reliability.

“Significant volumes of renewable gas can be produced within the EU, reducing Europe's import dependency.”

Security of supply

Security of supply is an important pillar of the Energy Union and an important driver for the energy transition. This study shows that choosing an energy system with renewable gas can provide the EU a reliable and secure energy system.
Renewable gas produced within the EU increases the redundancy and stability of the energy system. This study shows that large quantities of biomethane can be produced within Europe, abiding by strict sustainability criteria, reducing the import dependency of the European energy system. All generation of electricity takes place within Europe. These considerations ensure a strong European Energy Union where all countries contribute.

Renewable gas production can strengthen the rural economy

The incomes of European farmers partly depend on EU subsidies. An increase of farmers’ revenues from biomethane production would reduce their dependency on subsidies and improve their quality of life and their ability to invest. Also, if biomethane production is based on sequential cropping (Biogasdoneright) the earnings from production on existing cropland increase.

4.5 Cost savings curve

At the start of this chapter we described how the 122 bcm renewable gas in 2050 is allocated over the economic sectors where we anticipate the highest societal cost savings. We allocated most renewable gas to the buildings and electricity generation sectors and a smaller quantity to transport. In addition, we allocate a quantity of 45 bcm of biomethane to industry that should be sufficient to decarbonise that sector by 2050, although we did not quantify the cost savings from using gas in industry.

This chapter also described the quantification of societal cost savings from using 72 bcm of renewable gas allocated to heat buildings and provide peak electricity, which can lead to 138 billion euro of annual societal cost savings by 2050. The allocated quantity of 5 bcm of renewable gas to help to decarbonise heavy duty transport is cost neutral or slightly more expensive compared to the use of biofuels, and provides a sustainable and scalable alternative to decarbonise heavy transport. The figure below shows the increasing amounts of renewable gas and their associated annual societal cost savings. This study does not estimate a certain consumption level of natural gas with CCS, given high uncertainties related to technical availability (long distance transport and storage within the EU) and societal acceptance. We performed an illustrative quantification of cost savings from using a quantity of 132 bcm natural gas with CCS[70] which shows that also the use of low carbon gas leads to societal cost savings compared to an energy system without any gas.

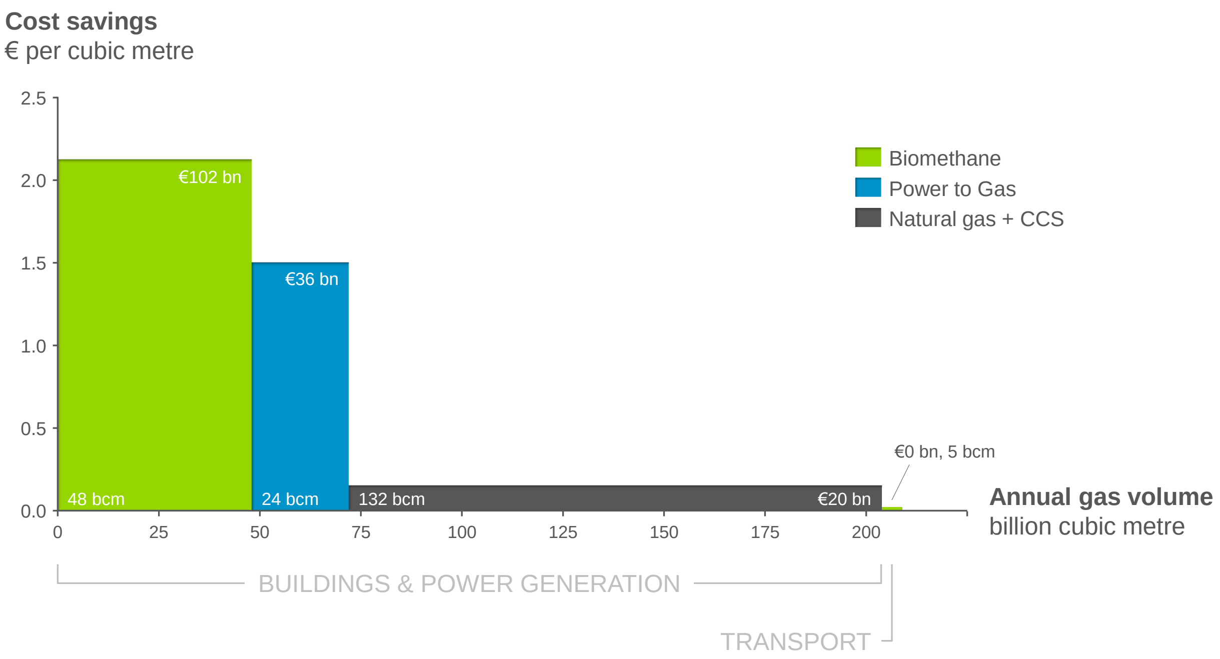

Figure 16 Renewable and low carbon gas annual cost savings curve. Figures are annual savings in the year 2050

[70] Cost savings calculations are based on assumptions for power generation (section 4.2.3).

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