European Carbon Neutrality: The Importance of Gas

A study for Eurogas

Report No.: OGNL.180049
Date: 30 June 2020

Project name:	Pathway study for Eurogas	DNV GL
Report title:	European Carbon Neutrality: The Importance of Gas	Energieweg 17
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Date of issue:	30 June 2020	Tel: [+00 000 000 000]
Project No.:	10157498	[Company Reg No]
Organisation unit:	DNV GL Netherlands B.V.	
Report No.:	OGNL.180049	

Applicable contract(s) governing the provision of this Report:

Objective:

To assess the role of gas in decarbonized European energy systems in 2030/2050

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Keywords:

Energy Transition, Decarbonization, Natural Gas, Hydrogen, Biomethane, CCS, European Union, ETOM,

Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
1	2020-04-01	Draft report	WtK, AvdN, MV, OÖ	BB	JK
2	2020-06-09	Final Draft Report	WtK, AvdN, MV, OÖ	BB	JK

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EXECUTIVE SUMMARY

Considerable efforts to mitigate and adapt to climate change are needed to keep Europe's societies habitable. The European Commission (EC) is committed to tackling climate change head on and aims to make Europe the world's first climate-neutral continent by 2050. The impact of transitioning to a net zero economy without greenhouse gas (GHG) emissions will be felt throughout the EU and in the energy sector in particular.

The European gas industry must find ways to thrive in a world where greenhouse gas emissions are gradually eliminated. This will mean supporting a vast expansion of renewable electricity generation and aggressively reducing emissions from fossil fuel use. This report was commissioned by Eurogas and investigates a continued and supporting role for gas in a decarbonized European economy by 2050.

To assess how to achieve a decarbonized future for the European energy sector and European consumers DNV GL developed a 100% CO_2 emissions reduction pathway (net zero) - labelled the 'Eurogas scenario'. This scenario builds on the strengths of the European gas sector and the advantages of energy delivery through existing gas networks. The Eurogas scenario was subsequently compared with an alternative pathway focusing on replacing gaseous energy with (primarily) electricity. This is called the 1.5TECH scenario in this report, and is DNV GL's interpretation of the EC's 1.5TECH scenario presented in 2018 as part of the *"long-term strategic vision for a prosperous, modern, competitive and climate neutral economy"*.

In both scenarios, all sectors need extensive decarbonization to achieve the reductions in emissions needed to meet the EC's net zero target by mid-century. In particular, it is clear that the electricity generation and manufacturing sectors (in both scenarios) must go carbon negative to achieve this. In the Eurogas scenario, electricity generation and manufacturing use energy produced from biomethane and biomass – decarbonized through carbon capture and storage (CCS) technology – to compensate for the remaining emissions produced by the increasingly less carbon-intensive buildings and transport sectors. The same occurs under the 1.5TECH scenario, although to a lesser extent. This scenario sees emissions reduced more evenly across all sectors.

There are several noteworthy similarities between both scenarios:

- Decarbonization of the electricity and manufacturing sectors depends on CCS technology and infrastructure being scaled
- Biomass use and second-generation biomethane technologies are pillars of Europe's decarbonization efforts. They are crucial for net negative emissions
- The road transport sector becomes increasingly electrified in both scenarios lead by battery electric vehicles (BEVs). Fuel cell electric vehicles (FCEVs) complement BEVs in commercial road transport.

In both scenarios, energy demand from the buildings sector does not reduce to the same extent as in other sectors in 2050. However, the energy carrier supplying this sector varies between the two scenarios. In the Eurogas scenario, natural gas and the scaled use of biomethane and hydrogen continues to deliver a substantial share of the sectors energy use. While in the 1.5TECH scenario a strong increase in the use of electricity for heating is observed.

The overall comparison of the two scenarios provides us with the following key findings:

Decarbonization of the European energy system

- In 2050 gaseous energy supply continues to play an important role delivering 32% of European final energy demand in the Eurogas scenario.
- The use of biogas and biomethane can result in significant negative carbon emissions (when coupled with CCS) making cost-efficient emission reduction available for otherwise hard-to-decarbonise sectors of energy demand.
- Hydrogen, biomethane and CCS can reduce the carbon footprint of the European gaseous energy supply chain by 89% in 2050 (and beyond if net negative emissions are included) in the Eurogas scenario.

Costs to society

- Continued gaseous energy supply in the Eurogas scenario delivers a net zero energy system at significantly lower cost (130 billion euro in annual savings) in 2050.
- Gaseous energy use reduces the cost of extensive renovation of the building sector and power grid expansion to accommodate for all-electric heating. It therefore provides society with a cheaper pathway to reducing emissions (~10 trillion euro in savings between 2018-2050).
- Continued use of gaseous energy in the Eurogas scenario reduces the estimated capex for European power grid expansion by around 1.3 trillion euros until 2050 (compared with the 1.5TECH scenario).

Decarbonization of gas supply

- Hydrogen production through methane reforming coupled with CCS (blue hydrogen) supplies the bulk of medium-term demand for hydrogen, reaching 820 terrawatt-hours (TWh) of supply in the Eurogas scenario in 2050.
- In both scenarios CCS is an indispensable technology for the decarbonization of the power and manufacturing sector with capacity between 895 and 1048 million ton of CO_2 sequestered per year (CO_2/yr) in 2050 for the 1.5TECH and Eurogas scenario respectively.
- Increasing availability of Variable Renewable Energy Supply (VRES) and cost reduction in electrolysis technology cause hydrogen production from renewable electricity ("green hydrogen") to reach 964 TWh in 2050 in the Eurogas scenario.
- Biomethane (second generation) can sustainably deliver 1014 TWh of energy in 2050, with supply costs impacted by feedstock scarcity in the longer run.

Infrastructure investment needs

- The combined effect of continuing the use of gaseous energy supply infrastructure and demand response technologies in the power sector reduce the peak-to-average capacity need by 19% from 2017 to 2050.
- Investment need for the continued use of gaseous energy is a fraction (11% of total capex in the Eurogas scenario) compared to the investment needed in the build-up of power grids to 2050.
- In the Eurogas scenario over 80% of the investment need in gaseous energy networks is for the accommodation of hydrogen into the networks (blended, retrofit and new build).

An energy supply for society

The energy sector underpins much of the lifestyle that citizens of advanced economies have become accustomed to, and that developing economies are increasingly relying on. Therefore, the symbiotic relationship between the need to decarbonise and the means that society has available to deliver decarbonized energy, are crucial to achieve deep decarbonization. As such, economic costs to society are of special concern, particularly to the economically disadvantaged.

In the Eurogas scenario, the total cost of delivering the EC's net zero ambitions by 2050 is 4.1 trillion euro (7%) lower than the 1.5TECH scenario. This difference approximates 0.5% of European GDP. This is equivalent to saving 130 billion euros per year or 600 euros per household per year over the 32-year period between 2018 and 2050. There are two primary reasons for the lower costs in the Eurogas scenario:

1. The subsidies required to incentivise/help consumers choose decarbonized energy are 80% or (10.1 trillion euros) lower in the Eurogas scenario. The comparable 1.5TECH scenario requires subsidies of 300 billion euros per year to electrify heating in the buildings sector.
2. The Eurogas scenario saves cost by repurposing the existing gas infrastructure instead of building new electricity infrastructure. The capex need in gas and electricity networks combined are 35% lower in the Eurogas scenario than in the 1.5TECH scenario.

1 INTRODUCTION

Mitigating and adapting to the challenge of climate change will require considerable efforts to ensure full decarbonisation, while safeguarding and growing the prospects for future generations. The European Commission (EC) is committed to achieve this ambition, presenting the European Green Deal in late 2019 as a roadmap to reach this goal: "*A growth strategy to transform the EU into a fair and prosperous society, with a modern, resource-efficient and competitive economy where there are no net emissions of greenhouse gases in 2050 and where economic growth is decoupled from resource use.*"

The EC proposed a European Climate Law on 4 March 2020 in order to embed the Green Deal's goal of achieving climate neutrality by 2050 into European Union (EU) legislation. This would enable the EU to contribute to achieving global net zero emissions by 2050 – a measure that would keeping global warming within the Paris goal of 'well below 2 degrees'.

When presenting the draft Climate Law, EU Commission's Vice President Timmermans stated that the current Covid-19 pandemic strengthens the need for action on climate change and a European Climate Law rather than negates it. [1] This indicates continued EU resolve to press on with the Green Deal agenda, ideally aligning immediate post-Covid recovery policies with the Deal's carbon neutrality objectives. [2]

The transition to a net zero economy will be felt throughout the EU, and particularly the energy sector. Presently, Europe consumes around 500 billion cubic meters (bcm) of natural gas annually. [3] Given the abovementioned climate goals, it is difficult to see a future for continued, robust demand for unabated natural gas. This was already recognized in the EU's *Strategic long-term vision for a prosperous, modern, competitive and climate neutral economy (SLTV)* published in November 2018. [4] The baseline scenario in the SLTV —assuming current policies put in place by the Member States— already projected a 30% decline in natural gas use between 2015 and 2050. [4]

For the European gas industry to support a net zero energy system, it must find ways to survive and thrive in a world where greenhouse gas emissions are continuously reduced and eventually eliminated. This will not only mean supporting a vast expansion of renewable electricity generation, but also aggressively reducing the emissions associated with natural gas use. Both of these tasks are achievable through the development of a decarbonised gaseous energy supply consisting of hydrogen, biomethane, and gas decarbonized through the application of CCS technology.

This report investigates a continued and supporting role for gas in the transition of the European energy system towards 2050.[1] To do this we have modelled two different scenarios using our proprietary Energy Transition Outlook Model (ETOM) that deliver two different energy futures that both reach net zero CO_2 emissions for the European energy sector in 2050.

One scenario builds on the strengths of the European gas sector and the advantages of delivering energy to society through gas networks. This Eurogas scenario sees a continued, albeit changing role, for gaseous energy in a zero emissions future for Europe. The Eurogas scenario is compared with an alternative pathway focusing on replacing gaseous energy with electricity as the preferred energy carrier for the energy transition. We dubbed this scenario the "1.5TECH" and is DNV GL's interpretation of the European Commission's 1.5TECH scenario presented in 2018.

This study analyses the difference in the cost of transitioning to net zero carbon emissions between the two scenarios.

[1] This reports investigates CO_2-emmissions related to energy supply and use, but also CO2-emissions related to processes in the manufacturing sector

This report starts by presenting our methodology, the scenarios and the high-level outcomes of the two energy futures. We then explore the role of gaseous energy by discussing three decarbonization options: biomethane, hydrogen and the use of CCS technologies. We also provide the forecasted energy mixes for the major energy consuming sectors under the Eurogas and 1.5TECH scenario, and finally we outline the benefits to European consumers by comparing the costs of the net zero energy system in both scenarios.

2 A DECARBONIZED EUROPEAN ENERGY FUTURE

2.1 Scenario introduction

The 2015 Paris Climate agreement pursued "*to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius*". [5] It thus aimed to set the world on an ambitious path of global greenhouse gas reductions.

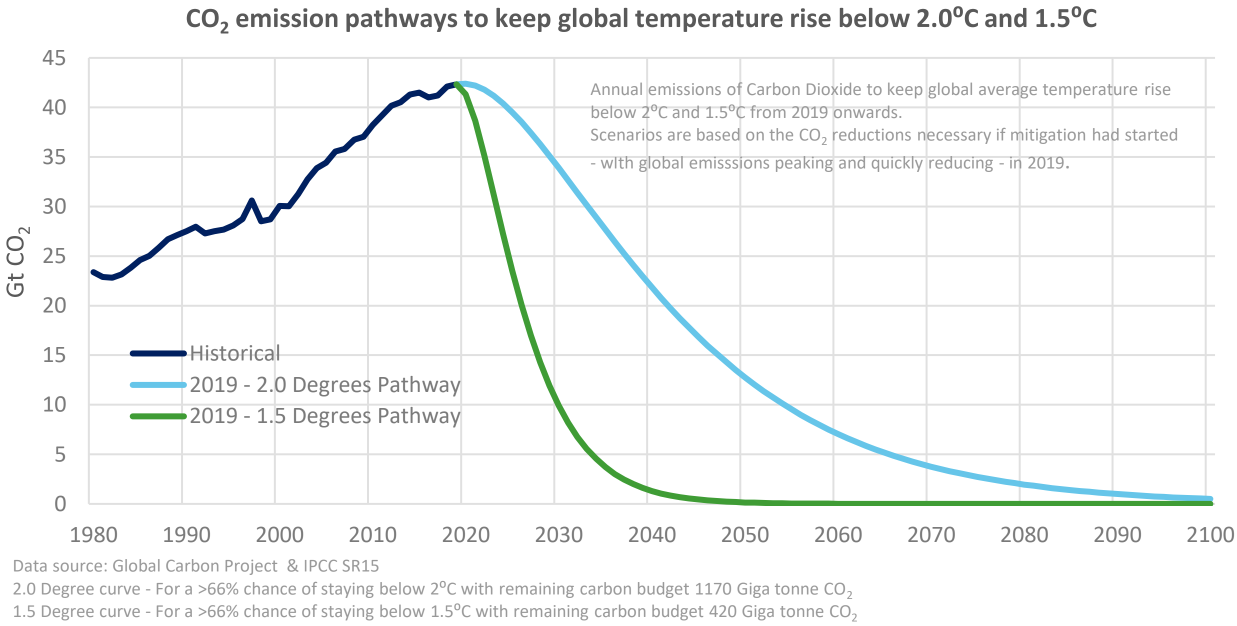

Figure 1 Carbon reduction pathways for 2 and 1.5 degrees temperature rise[2] [6]

However, since 2015 the realizations have failed to meet ambitions: as emissions have steadily risen, the remaining carbon budget has decreased leading to increased urgency and deeper cuts needed to limit the global rise in temperatures. Although increases in global energy related emissions flattened in 2019, figure 1 shows future carbon reduction pathways available, but they are becoming increasingly challenging as time progresses, particularly with regard to the limits on the carbon budget associated to the 1.5 degree pathway. [6]

DNV GL's global Energy Transition Outlook, which forecasts and provides the CO_2 emissions related to energy use (including process emissions from manufacturing)[3] does not see the Paris Agreement ambitions achieved. In 2019 we forecasted that compared to 2018 by 2050, globally 45% of energy-related CO_2 emissions are eliminated. For Europe, arguably the most "climate conscious" developed economic region in the model this resulted in a 72% emissions-reduction (compared to 2018 levels).[4] As such additional decarbonization efforts are urgently needed (also globally) on top of those that were already on the horizon in 2019.

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[2] Annual emissions of Carbon Dioxide under various mitigation scenarios to keep global average temperature rise below 2°C. Scenarios are based on the CO2 reductions necessary if mitigation had started - with global emissions peaking and quickly reducing - in the given year.

[3] DNV GL's Energy Transition Outlook is updated and published yearly the 2019 edition available at: https://eto.dnvgl.com/2019/index.html

[4] The underlying model, ETOM, is based on behavioural economics, and ensures that cost effective energy solutions are preferred by decision makers, given the current political, institutional and cognitive constraints (but no new policies, beyond the already announced at the date of publication are included in the forecast). The model is used in this study to asses alternative pathways that meet a net emissions energy future in 2050.

The new European Commission, acknowledged the growing urgency to act and the existential threat that Climate Change poses when it unveiled its "Green Deal" in December 2019, that sought to develop: "a new growth strategy that transforms the Union into a modern, resource-efficient and competitive economy". [2]

Core pillars of this "Green Deal" strategy for the European Union are formulated as following:

- there are no net emissions of greenhouse gases by 2050
- economic growth is decoupled from resource use
- no person and no place is left behind

The "Green Deal" radically increases the overall decarbonization ambitions of the largest economic bloc in the world (responsible for 9% of GHG-emissions and 22% on a cumulative basis since 1850 in 2018) [7] to net zero by 2050. In addition, an intermediate economy wide decarbonization target of 50 to 55% was tentatively proposed raising the bar from the earlier 40% decarbonization target. Finally, the European Commission provided a road map for legislative actions to support the Green Deal with a timetable for 2020-2021.

As a first step, the key (draft) legislative proposal for a "Climate Law" was unveiled on March 4th that aims to enshrine the 2050 climate neutrality objective in European (and subsequently Member State) legislation. Despite the growing, and ongoing, uncertainty surrounding the consequences of the global Covid-19 pandemic on European economies this aim of climate neutrality by 2050 is broadly supported.

To assess how to achieve a decarbonized future for the European energy sector and European consumers DNV GL was commissioned by Eurogas to develop a 100% CO_2 emissions reduction pathway (net zero) - labelled the 'Eurogas scenario' - and compare it with DNV GL's interpretation of the European Commission's 1.5TECH scenario that was presented in 2018 as part of the *"long-term strategic vision for a prosperous, modern, competitive and climate neutral economy"*. We have remodelled the latter scenario through DNV GL's own Energy Transition Outlook Model (ETOM) to match, as closely as possible given the data available to us and its outcomes [3].

The two scenarios both arrive at net zero CO_2-emissions related to the use of energy (including industrial process emissions) in Buildings, Transport, Manufacturing and Power generation. The related CO_2-emissions do not include other GHG-emissions and emissions from other economic sectors, particularly agriculture and waste management. As such both scenarios are not an economy wide net zero decarbonization pathway, but do represent a proportionate contribution from the energy sector to such a pathway as it makes up 75% of all CO2 related emissions.[5]

We primarily compare the outcomes of Eurogas and 1.5TECH scenarios as these both have the European region as their focus. However, sometimes we will refer to the ETO2019 forecast as to illustrate the strengthened efforts required to achieve net zero emissions versus our own forecast which does not meet this objective. Although both the Eurogas and 1.5TECH scenario reach 100% CO_2-reductions by 2050, they achieve this objective in two distinctly different ways.[6]

[5] As these modelled emissions do not include economy wide emissions we investigated whether they would constitute a representative contribution toward a net zero economy. As EEA emission data show a near linear correlation between economy wide GHG-reduction and CO_2-reduction in the energy sector, as such the 55% emissions reduction can be considered a representative contribution for the energy sector to the "Green Deal".

[6] For a comparison of the input values and modelling approach of the scenarios see Appendix A.

1. The Eurogas scenario represents a choice for gaseous energy delivery in which the existing gas infrastructure continues to be used to deliver a decarbonized energy supply. This includes an important role for the supply of renewable and decarbonized gases. As such, it focusses on an evolution of the existing energy system through ease of adaptation and implementation.

   In this scenario gaseous energy provides a backbone for the transforming European economy through the supply of decarbonized gaseous energy to all economic sectors as a mix of natural gas, biomethane and hydrogen, complemented with CCS technology that help deliver neutral or net negative emissions.

2. In contrast, the 1.5TECH scenario supports the decarbonization of energy demand in the individual economic sectors through (renewable) electricity uptake where other sources of energy are now supplied.

   The role of natural gas in this scenario is a distinctly supportive (primarily to the power sector), and (in the long term) diminishing one. This scenario limits biomethane and hydrogen supplies to hard-to-decarbonise sectors and is therefore not an all-electric scenario.

As a point of comparison, DNV GL’s ETO2019 baseline is a forecast of expected changes in the energy system. Many of these are trend extrapolations of cost declines. The forecast is what DNV GL considers *‘a best estimate future’*. Globally, it sees decarbonization policies reflect the Paris ambitions, but not fully. Thus, by 2050 global CO_2-emissions are cut in half from current levels in the ETO 2019.

In our 2019 forecast, CCS takes off mid-century with natural gas supply playing a dominant role in decarbonization due to fuel switching from coal to gas. Hydrogen plays a role in manufacturing, buildings and heavy road transport. The use of Biogas and Biomethane stagnates at current levels. Electrification of buildings and light vehicles, and use of wind and solar energy are the main vehicles for decarbonization. However, in Europe decarbonization efforts fall short of the Paris agreement and reach only a 76% decrease in GHG emissions from 1990 levels by 2050. Increasing the need to explore more ambitious pathways.

Figure 2 below shows what both the Eurogas and 1.5TECH scenario reveal in terms of electricity's and gas' (comprising of natural gas, biomethane and hydrogen) shares in final energy demand. In 1.5TECH, electricity's share in final energy demand sharply increases to more than 50% in 2050. At the same time, gaseous energy supply is reduced to 20% in 2050. In the Eurogas scenario, both the shares of electricity and gaseous energy delivered to consumers increase. Even though electricity increases its share in final energy faster than gaseous fuels, its share is more balanced with gaseous energy in 2050 and does not witness as steep a development as in the 1.5TECH.

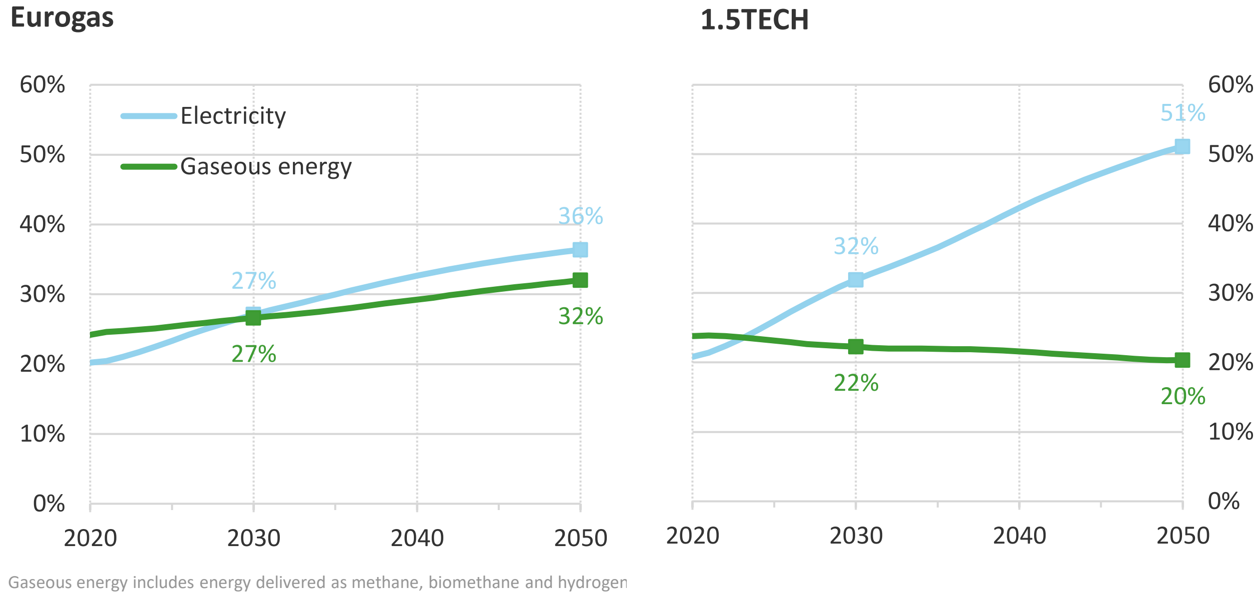


Figure 2 Share in final energy demand by scenario

In general energy policy makers will try to achieve a balance in the "Energy Trilemma" of policy objectives otherwise known as the triple A's: Availability (secure energy supply), Affordability (cost efficient energy supply) and Acceptability (environmentally sustainable energy supply).

In this analysis two of the three pillars of energy policy making are 'fixed', namely Availability and Acceptability, as DNV GL's ETO model ensured that:

1. Demand and supply are matched (for the power sector on an hourly basis) for every year until 2050;
2. The net zero CO_2 emissions target establishes what is considered (at an overarching European level) environmentally acceptable in 2050.

The scenarios also share identical technologic and economic assumptions such as:

- Technology starting costs for the year 2017;
- Technology learning rates for key supply technologies VRES, natural gas reforming, CCS, biomass gasification and electrolysis;
- Conversion efficiencies in power sector and critical user technologies.

Overall cost competition within the ETOM determine which technologies are selected to supply energy to consumers, and thus how various energy supply options compete over time. This cost competitiveness can subsequently be influenced by specific technology support mechanisms (e.g. subsidies), and an overall carbon price. This sequence then generates two different decarbonized energy systems in 2050 that can be compared on costs.

The main differentiator between the two scenarios is then 'Affordability' or the costs European societies will incur for a specific energy supply system. Next to the fuel/generating cost, the costs of transmission and distribution, the energy system faces a number of costs induced by authorities, such as neutrality fees to finance support schemes and subsidies, consumer taxes and VAT. These costs fluctuate through time as the current energy supply system evolves into a net zero energy supply system.

Each scenario features a uniform carbon price applicable to all sectors of energy demand (this uniform carbon price is different between the Eurogas and 1.5TECH scenario). In addition, each scenario also features public support (through subsidies) to specific consumers ("energy poverty"), technologies and sectors as to help decarbonise the energy system as a whole.

One of the most influential of these state-induced costs is the uniform carbon price. The 1.5TECH scenario is defined by a carbon price of 350 EUR/tCO_2 that ensures net zero emissions by 2050.[7] The Eurogas scenario requires a more modest 100 EUR/tCO_2 carbon price in 2050 to achieve the same net zero emissions goal. For reference, our 2019 ETO forecast forecasts carbon prices doubling to 50 EUR/tCO_2 in 2050 (See Appendix C for energy and carbon price developments).

2.2 Decarbonization, primary energy supply and costs

Our ETO 2019 CO_2-emission forecast points towards 2.4ºC warming of the planet by the end of this century. CO_2-emission reductions in Eurogas and 1.5TECH both reach 100% compared to 1990-levels in 2050 and also meet the 2030 decarbonization targets of 50-55% in 2030 (Figure 3). These pathways thus support the EU member state commitments to deliver Europe's fair share in global emission reduction.

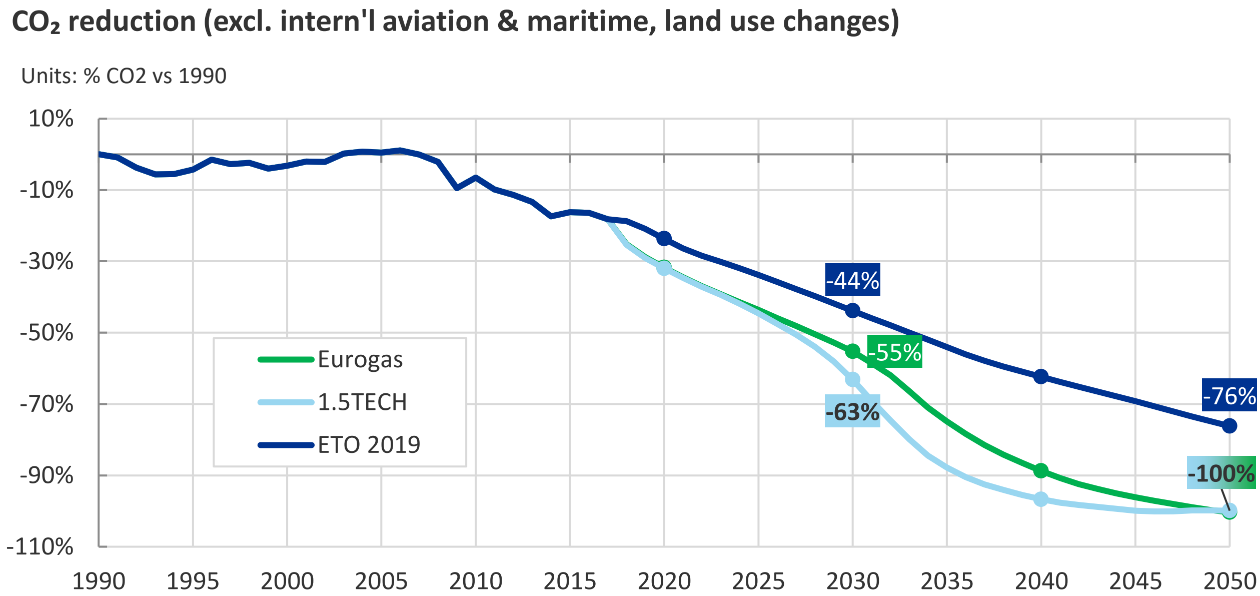


Figure 3 CO_2 reduction for each scenario in Europe

As the ETO2019 forecast does not achieve the net zero decarbonization objectives it shows that the forecasted EU policies, notably emission pricing, do not sufficiently incentivise the roll-out and uptake of the available demand-, transformation-, and supply technologies fast enough to achieve the decarbonization required. However, whilst the ETO2019 does not achieve the overall decarbonization objectives set out by the European Commission, both the Eurogas 2019 and 1.5TECH scenarios do, albeit at different speeds.

Emissions are reduced more gradually under the Eurogas scenario with 30% (1.37 Gt CO_2) of required CO_2-reductions from 1990 levels achieved between 2018-2030 and 45% (2.06 Gt CO_2) between 2030-

[7] A steadily increasing carbon price of 350 EUR/tCO_2 in 2050 is also applied in the EC's original 1.5TECH pathway. DNV GL's interpretation of this pathway also arrives at 350 EUR/tCO_2 in 2050, but requires a higher intermediate carbon price level to achieve overall decarbonization in combination with sectoral energy supply mixes. Also see Appendix A and C.

2050. 1.5TECH follows a steeper path with 38% (1.73 Gt CO_2) of CO_2-reductions (of 1990 level emissions) achieved between 2020-2030 and 37% (1.68 Gt CO_2) between 2030-2050. However, Eurogas' more gradual path comes with lower overall cost to society and reduced overall risks to implementation.

Primary energy supply in all three scenarios decreases resulting in similar outcomes in 2030 (Figure 4). However, as the carbon price pressure increases at different levels different energy efficiency improvements are causing energy supply levels to diverge toward 2050.

Increased electrification of economic sectors is a primary driver of energy efficiency for all scenarios. DNV GL's ETO 2019 forecast showing the steepest decline (37%) ending up at 12.700 TWh/year by 2050. However, the ETO2019 scenario has considerable unabated CO_2-emissions in buildings and heavy transport which account for 60% of remaining CO_2-emissions in 2050. Both Eurogas and 1.5TECH see a decline (29% and 34% from 2030 levels respectively) in primary energy use, with Eurogas' primary energy supply level at 14.500 TWh/yr in 2050.

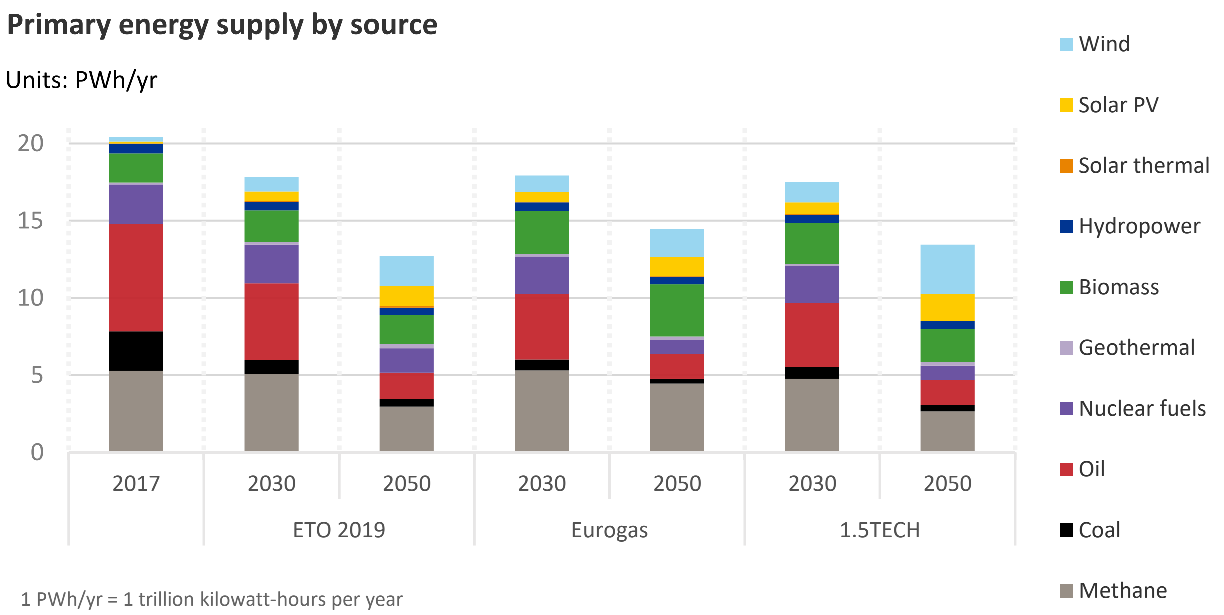


Figure 4 Primary energy supply by source in Europe

Total costs for the Eurogas scenario over the period 2018-2050 are 4.1 trillion euro (7%) lower compared to the 1.5TECH scenario, equalling to about 130 billion euro per year.[8] Figure 5 details the total cost to the economy for all three scenarios.

[8] We performed an analysis to validate our findings regarding the lower costs to the economy of the Eurogas scenario and the relative impact of the carbon price difference (100/350 EUR/tCO_2) for both scenarios. This has led us to conclude that our asessment of the lower costs to the economy for the Eurogas scenario have been prove robust. (for analysis see appendix C)

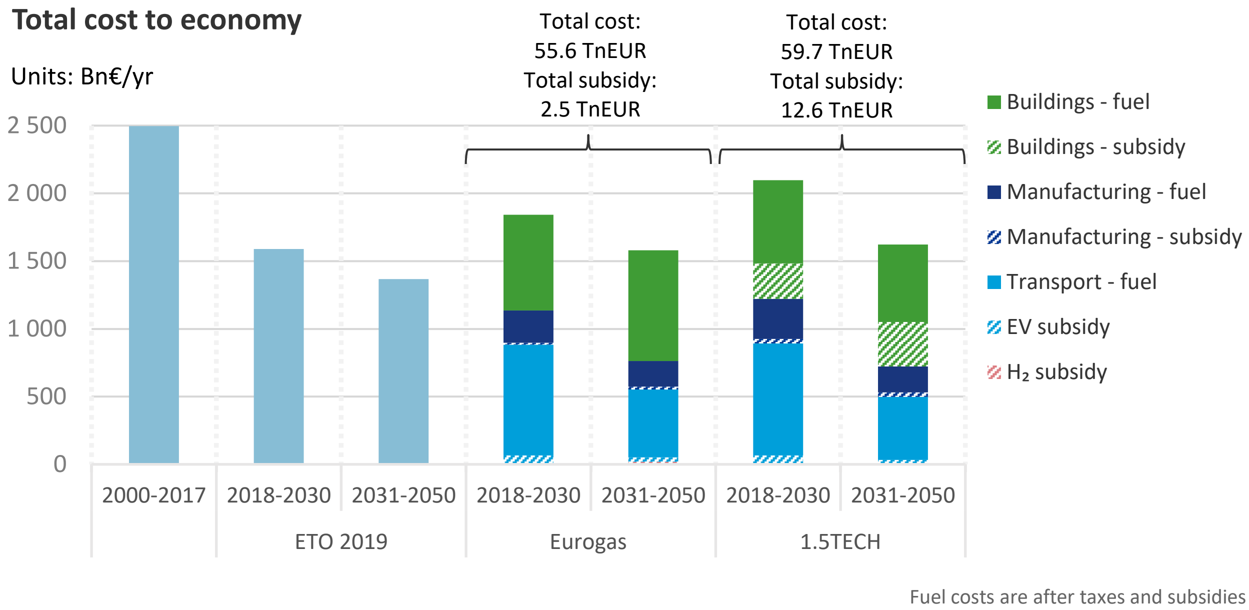


Figure 5 Total cost to the European economy of ETO 2019, Eurogas and 1.5TECH scenario

The scenario cost differentials stem mostly from subsidies incentivising consumers to choose decarbonized energy (e.g. tax breaks, investment grants etc.). Such subsidies are 80% (10.1 Trillion euro) lower in the Eurogas scenario over the forecasted period.

The trade-off between subsidies and energy costs is most prevalent in the buildings sector, where the 1.5TECH scenario requires subsidies of roughly 300 bln euro per year to electrify heating demand.

Significant savings can be obtained through using existing gas infrastructure instead of developing new electricity infrastructure. This is an important factor for the Eurogas scenario's lower costs: The power grid CAPEX requirements are 34% (1.3 trillion euro) lower in the Eurogas scenario as are the risks

Textbox 1 - Definitions of costs

Fuel Costs: All costs of energy to final energy users, including production, transmission, distribution, supply and marketing, and taxes, but discounting eventual subsidies

Subsidies: all direct or indirect payments, economic concessions, or privileges granted by EU or Member States governments to energy users, such as private firms, households, and governmental units

associated to such a large capital intensive infrastructure build-up.[9] In total, network investments in the Eurogas scenario are 35% lower than in the 1.5TECH scenario for 2018-2050, with a decline of 1% per year on average for 2018-2050 compared to the years 2000 to 2017.

As shown in Figure 6, investments in the power grid dwarf the investment in the gas network in both scenarios. To 2050 investment in gas supply networks in the Eurogas scenario are 10% of total network investments (5% of total network investments in the 1.5TECH scenario). As (decarbonized) gaseous energy supply increases by 18% (936 TWh) in the Eurogas scenario, the associated additional

[9] General financial, development and societal risks that can be associated with any energy project/investment. Such as delays, cost overruns, stranded asserts, NIMBY and public support in general.

investment needs for expanding, refurbishing and decommissioning gas networks are on average 4.2 bln Euro per year higher than the investments needed in the 1.5TECH scenario where 31% (1630 TWh) less gaseous energy is supplied to final customers in 2050.

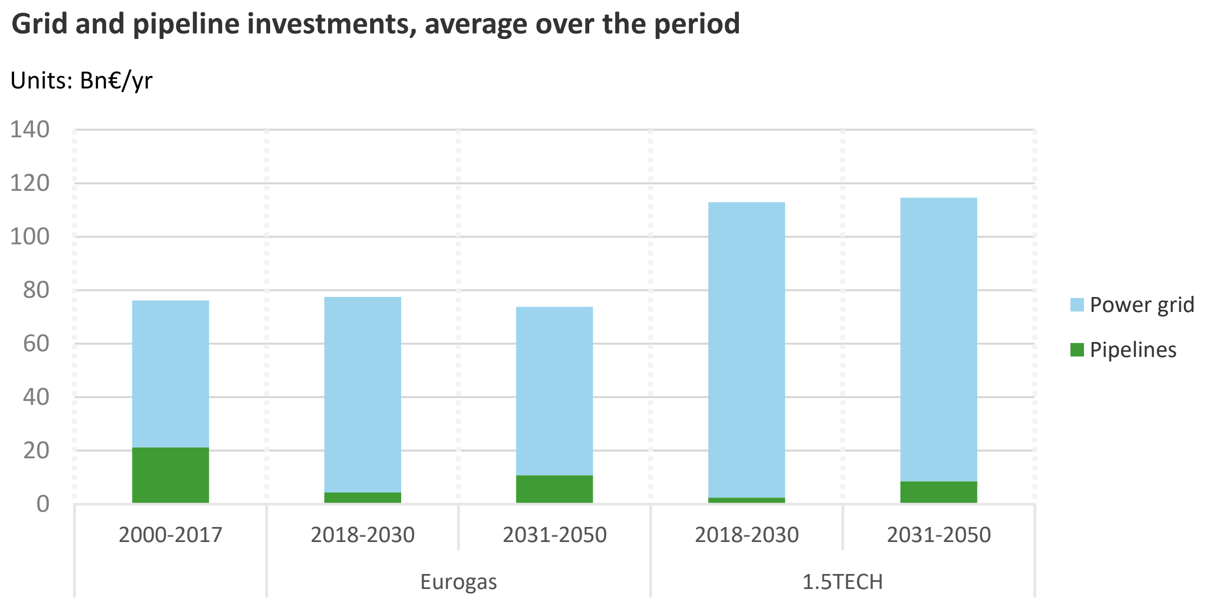


Figure 6 Investments in gas and electricity networks, average of the indicated periods

The two alternative scenarios demonstrate that reaching EU-wide net zero emissions in 2050 is possible. While both scenarios require a massive outlay in capital spending and political determination to achieve their net zero objectives, continued use (and investment in) gas grids and gaseous energy supply is a less costly way for Europe to fully decarbonise.

2.3 Pathways towards net zero decarbonization

We assessed the high level outcomes of the Eurogas scenario with alternative scenarios that reach Paris Agreement Compliant" decarbonization outcomes in 2050 (95%-100% decarbonization) for the European energy sector.[10]

In comparison to the Eurogas scenario, two additional scenarios were analysed: the 2018 Eurelectric study on "*Decarbonizing Pathways*"[11] and the 2019 Gas for Climate study on "*The optimal role for gas in a net-zero emissions energy system*"[12]. In Table 1 the main commonalities and differences of each scenario are outlined, indicating that the scenarios are roughly comparable in overall ambition and scope.

[10] For the expanded comparison see Appendix D of this report.

[11] Available at: https://www.eurelectric.org/decarbonization-pathways/

[12] Available at: https://gasforclimate2050.eu/publications/

Table 1 – Scope of the three decarbonization studies

	Eurogas	Eurelectric - 95%	Gas for Climate - OGS
Geographical	Global, covering 10 regions, with Europe (EU-27 plus UK, Norway, Switzerland and Balkans) as one region	Global, covering 8 regions and the EU28 plus EEA	EU-28
Timeframes	Annual up to 2050, results available for 2030 and 2050	Annual projections up to 2050	Results only for 2050
Sectors	Power, Manufacturing, Buildings, Transport	Power, Industry, Buildings, Transport	Power, Industry, Buildings, Transport
Emissions	Energy-related and process CO2 (incl. intra-European aviation and Shipping)	Energy-related CO2 (incl. international aviation)	Energy-related and process CO2 (incl. international aviation)

Eurelectric "Decarbonization Pathways" – 95% Decarbonization

The main objective of the Eurelectric study is to assess the role of electrification in transport, buildings and industry to achieve 80-95% decarbonization of the EU economy in 2050. Three scenarios are developed to assess implications for the European Power sector with one scenario (scenario 3) achieving 95% CO_2-emission reduction by 2050. To achieve this objective "*Major technology breakthrough*" are needed.

Gas for Climate – Optimised Gas Scenario (OGS) – 100% Decarbonization

The study aims to assess a cost-optimal way to fully decarbonise the EU energy system by 2050 and to explore the role of renewable and low-carbon gas used in existing gas infrastructure. Finally the study assesses the cost for society by comparing the OGS against a competing minimal gas scenario (MGS). The main body of the study was launched in 2019, and expanded with specific pathways for renewable gas supply in 2020.

High level scenario comparison

The high-level comparison in Table 2 is based on the individual reports available, highlights important differences between the three scenarios when looking at the (direct) electrification rate and gaseous energy consumption of final energy demand. Clearly the Eurelectric scenario's push for direct electrification results in higher share (60%) that the two alternative scenarios. Although the Eurelectric scenario provides limited information on the gaseous energy (still) delivered to customers in 2050, it is clear that this will remain significantly below the 32% of final energy consumption delivered in gaseous from in both the Eurogas and Gas for Climate scenarios.[13]

[13] The Eurelectric scenario does provide for 1200 TWh of indirect electricity consumption in 2050. Needed for energy use related to power-to-X and electricity demand driven by production of biofuels and CCS. If that would be directed to hydrogen production only (at a general 70% efficiency) this would amount to max. ~10% of gaseous energy consumption in the form of hydrogen.

Table 2 – High-level outcomes of the three scenarios

	Unit	Eurogas	Eurelectric - 95%	Gas for Climate - OGS
		2050	2050[14]	2050
Decarbonization	**(% vs 1990)**	**-100%**	**-95%**	**-100%**
Gross Inland Consumption	**(TWh/yr)**	**12.703**	**N/A**	**13.386**
Final Energy Consumption	**(TWh/yr)**	**9.831**	**8.417**	**9.019**
Buildings	(%)	50%	36%	11%
Manufacturing	(%)	22%	40%	16%
Transport	(%)	22%	24%	24%
Electrification[15]	(%)	36%	60%	49%
Gaseous Energy Consumption[16]	(%)	32%	N/A	32%
Gaseous Final Energy Consumption	**(TWh/yr)**	**3.148**	**N/A**	**2.880**
Hydrogen	(%)	57%	N/A	59%
Biomethane	(%)	11%	N/A	41%
Natural Gas	(%)	33%	N/A	N/A
Installed Power Generation Capacity	**(GW)**	**1926**	**2700**	**2795**
Renewable[18]	(%)	84%	83%	96%
Fossil	(%)	13%	~15%[17]	4%
Nuclear	(%)	3%	~2%[18]	0%
Power Generation	**(TWh/yr)**	**5.304**	**7.000**	**7.430**
Renewable[19]	(%)	78%	82%	92%
Fossil	(%)	16%	~5%[16]	8%
Nuclear	(%)	6%	~13%[17]	0%
CC(U)S Deployment	**(MTCO2/yr)**	**1.048**	**200**	**N/A**

Decarbonization pathways

All scenarios focus on decarbonization of the energy sector and assume the efforts in this sector are of a proportionate effort to achieve economy wide GHG-emission reductions put forward in the Paris Climate agreement in 2050.

For 2030 the Eurogas scenario achieves the intermediate goal of 50-55% decarbonization that is now the focus of the "Green deal" in 2030. For the two alternative scenarios it remains unclear whether the 50-55% target for 2030 is achieved. Although the 2020 Gas-for-Climate follow-up study does indicate that additional efforts are needed to achieve an accelerated 2030 pathway [8] the long run net zero emissions are primary. For 2050 the Eurelectric scenario does achieve a 95% decarbonization target which should be in line with the Paris Climate agreement objectives, but naturally does not achieve the net zero ambitions now put forward in the European Commission's "Green Deal".

[14] Decarbonization projected until 2050, energy supply/demand data available for 2045
[15] Direct Electricity consumption (excluding Hydrogen produced through electrolysis)
[16] Energy supplied as Biomethane, Natural Gas, and Hydrogen
[17] Natural gas fired power generation only
[18] Nuclear rest of capacity as coal is phased out
[19] Includes Wind, Solar, Hydro, Geothermal and Biomass

Energy efficiency

All scenarios see considerable energy efficiency gains as "Negawats" are arguably the best and easiest way to accelerate decarbonization of energy use. The Eurogas scenarios has a -1.2% yearly reduction in final energy demand (over the period 2015 – 2050) while Eurelectric achieves -1.3% per year for the same period. The OGS does not provide a starting point for final energy consumption, but when taking Eurogas scenario final energy demand in 2015 (14.820 TWh) achieves a reduction of -1.4% in yearly final energy demand.

Power generation

All scenario's see a massive and concerted push to expand renewable power generation resulting in high levels of variable renewable (VRES) power generation. This high penetration of renewables in all the scenarios is driven by both the untapped potential and the rapidly declining costs for both wind and solar. Eurogas scenario reaches the lowest share of renewable electricity production (3056 TWh in 2050) although in installed generation capacity achieves similar shares of capacity (84%) as installed in the Eurelectric scenario (83%).

Gaseous energy delivery

All scenarios see a clear (but undefined in Eurelectric) cost benefit of continuing gaseous energy supplies to certain economic sectors (e.g. not aiming for a 100% electrification) although for different reasons. Both the Eurogas and the OGS scenario aim to use the existing natural gas supply infrastructure, thus foregoing the additional investment needed in the power grid. Both these scenarios achieve similar shares (32% of final energy demand in 2050) of gaseous energy delivered to consumers.

The Eurelectric study does not provide an amount of gaseous energy delivered to consumers,[20] but does indicate that as power generation is net zero by 2045 that other technologies (such as CCS and power-to-gas) are needed to balance the electricity market and offset remaining emissions in other sectors.

Renewable gas supply

Both the Eurogas scenario and the OGS scenario project similar hydrogen and biomethane supply development with 1783 TWh (blue/green) hydrogen and 1014 TWh of biomethane supplied in the Eurogas scenario, and 1710 TWh of hydrogen and 1170 TWh of biomethane delivered in 2050. Both scenarios have biomethane production through gasification technologies as a core pillar for decarbonization in the scenarios.

Main differentiator is the significantly higher level of blue hydrogen production in the Eurogas scenario (46% in 2050), while the OGS sees electrolysis arriving as the mainstay for hydrogen production post 2040. In the OGS' blue hydrogen production is recognized as a technology that can help grow the hydrogen market in the short to medium term. The Eurelectric scenario this role is limited to a balancing one in support of the power sector with demand for Hydrogen driven by sectors and in need continued support to overcome advantageous power sector economics.

Role of CCS in decarbonization

All scenarios recognise the role that CCS can play in decarbonizing the energy system. Its contribution is however not extensively quantified in the Eurelectric and OGS scenarios. With Eurelectric limiting the EU wide uptake below 200 MT/year and OGS providing a rather wide potential range of 190 TWh and 1500

[20] The Eurelectric scenario does provide for 1200 TWh of indirect electricity consumption in 2050. Needed for energy use related to power-to-X and electricity demand driven by production of biofuels and CCS. If that would be directed to hydrogen production only (at a general 70% efficiency) this would amount to max. ~10% of gaseous energy consumption in the form of hydrogen.

TWh blue hydrogen production (as a proxy for CCS-need) in 2050. This contrasts starkly with the CCS uptake in the Eurogas scenario that reaches roughly 1 GT/yr in 2050.

CCS is a decarbonization technology with significant societal concerns that will need to be addressed to facilitate expedient uptake and deliver any of the decarbonization benefits (including net negative emissions). In addition to societal and NIMBY, technological maturity and technology cost are a particular factor in each scenario.

In the Eurelectric scenario CCS is considered *"immature and expensive*" it is stressed that "*there are potential synergies in technology development and scale advantages as it is also likely to be needed for other sectors where no other solution is feasible (e.g. abating process emissions in cement production)".* The Gas for Climate study stresses the technological readiness of CCS (and potential of other capture and use technologies), but does see uptake as uncertain due to societal concerns.

Cost to society

All scenarios consider a decarbonized energy future more costly to society than a "Business as Usual" scenario (not taking into account the likely devastating effects and costs of climate change on societies) due to an added investment need in the energy sector overall. Costs for society are difficult to compare due to the different costs used in the model and focus of the studies.

The Eurelectric study focusses on the power sector and indicates that most emissions could be abated at 18-64 Euro/ton, but that the last tons are significantly more expensive (e.g. 130 Euro/ton in the 95% decarbonization scenario). These are costs for the power sector, and as such do not provide an indication of costs in harder to decarbonise sectors such as industry and buildings that are likely to be considerably higher. Overall costs to society are not quantified for the Eurelectric scenarios.

The Eurogas scenario and OGS scenario derive at different (but significant) costs savings as both are compared to different alternative scenarios (Eurogas is compared to 1.5TECH, OGS to the MGS). The OGS sees average annual cost of 2026 billion Euro per year with 217 billion Euro of yearly savings to society. The Eurogas scenario sees average annual costs of 1670 billion Euro per year with 130 billion Euro of savings.

3 DECARBONIZING GAS

To achieve a net zero contribution of gaseous energy to the European energy system we have reflected gaseous energy usage and supply in four sub-types until 2050.

1. Hydrogen
2. Biomethane
3. Natural gas combined with CCS[21]
4. Natural gas

Considering the need for CCS to be applied to natural gas in a carbon neutral future, the first three subtypes are used to decarbonise gas demand. Biomethane is indistinguishable from natural gas once injected into the networks, while hydrogen can both be used purely in dedicated networks and blended with methane up to a certain level in gas networks used to supply consumers.

Carbon capture and storage refers to sequestering carbon atoms, usually as CO_2 molecules, from emitters and storing them in depleted oil and/or gas fields including their transportation to the storage site. CCS can be applied at the point of consumption but also to produce hydrogen from natural gas in a more centralized model. Technically, in the former case, both pre- and post-combustion of natural gas can be applied.

Under pre-combustion, natural gas is converted into a mix of mostly hydrogen and CO_2. The CO_2 is subsequently removed from this mix, while hydrogen is used as an energy carrier or act as a feedstock. Post-combustion CCS extracts CO_2 from exhaust gases after the fuels have been burned or converted into products when used as a feedstock.

In the centralized model, hydrogen is produced by reforming natural gas and the related emissions are captured and stored; hydrogen is then transported to end consumers. Hydrogen produced in this way is sometimes called 'blue hydrogen'. In essence, this is pre-combustion CCS where hydrogen is not used on site but distributed to different end consumers.

Lastly, hydrogen produced through electrolysis using renewable electricity as a source is referred to as 'green' hydrogen. Figure 7 below provides an overview of the cost of the three decarbonized gases included in our analysis.

An important driver for cost reductions are cost learning rates: with each additionally doubling of installed capacity, the cost of the technology comes down with a fixed fraction. Fixed learning rates are found in most technologies and include all effects that relate production volumes to cost reduction. This includes, but is not limited to, economies of scale -as average plant size typically increase and allow for efficiencies. Another factor is engineering, management, and man-power skills that improve with experience. Machinery tend to become more advanced, as more R&D resources allow for improvements, but also supply chains tend to become more efficient with added industry-level experience. A similar effect is also observed with the introduction of (renewable energy) technologies.

[21] In this analysis we assume that carbon which is captured is stored underground and not utilized as feedstock for other processes.

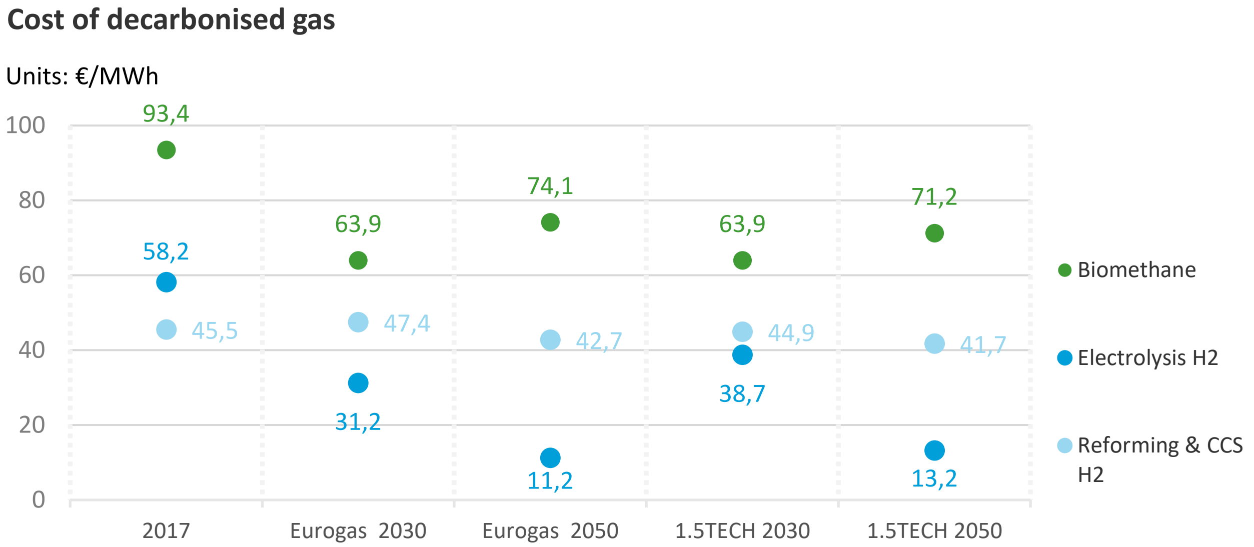


Figure 7 Cost of decarbonized gases

In addition to technology costs displayed in Figure 7 other costs such as biomass feedstock cost, power prices, and the cost of natural gas and CCS (i.e. the cost of the capture technology, and transport and storage) are also included.

The chart shows that most costs of decarbonised gases are expected to decrease over the forecasted period. However, biomethane costs will increase after 2030, especially as we approach 2050 when biomethane production pushes towards the limits of available sustainable feedstock. Consequently feedstock prices (second generation biomass) increase by 30% over 2030-2050. However, Biomethane prices rise by (only) 16% over the same period as cumulative learning effects have cut technology costs in half over the period 2018-2050. Both the technology-, and feedstock cost development which make up the total cost for biomethane cost are shown for the Eurogas scenario in Figure 8 below.

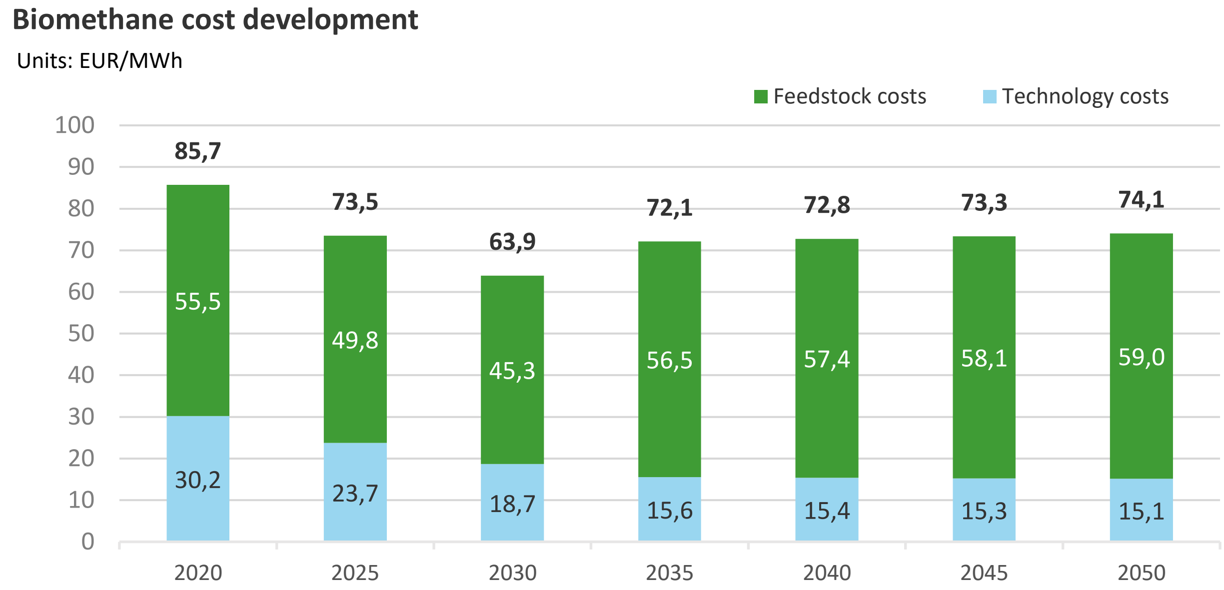


Figure 8 Development of biomethane costs by component in the Eurogas scenario

Looking towards 2050, the final demand—which excludes demand from power stations—for gaseous energy in the Eurogas scenario grows by 16% (843 TWh) compared to 2017 levels, while the 1.5TECH scenario sees a reduction of 31% (1630 TWh) in 2050. In terms of gaseous energy supply (Figure 9), the Eurogas scenario sees an increase of 18% (936 TWh) over 2017 levels (5,230 TWh) in 2050.

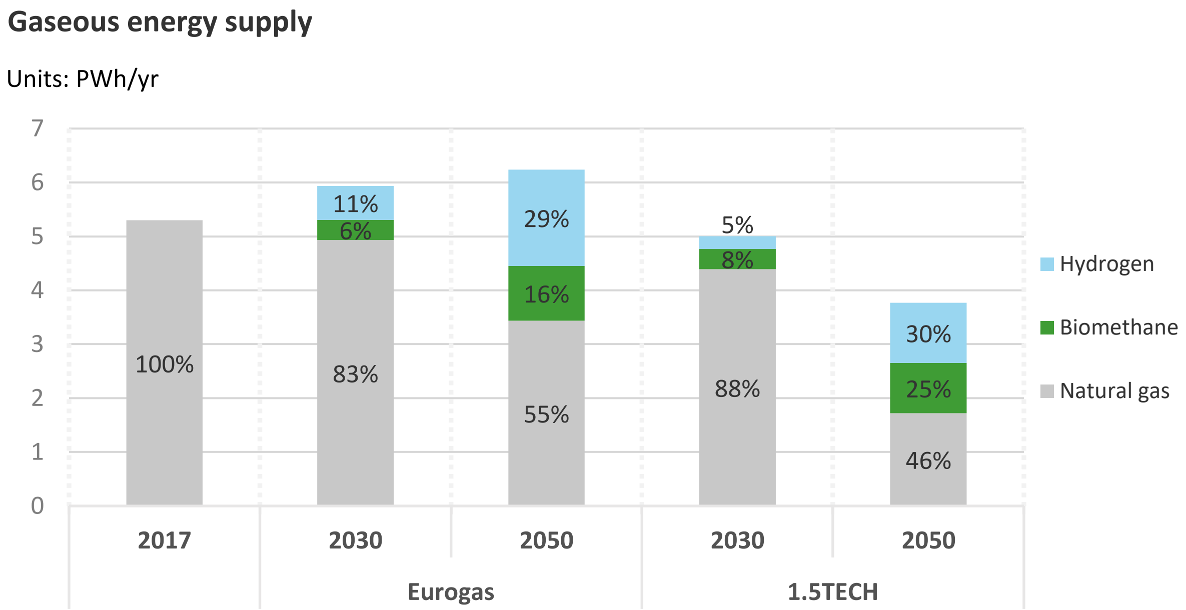


Figure 9 Gaseous energy supply under Eurogas and 1.5TECH

Although in the Eurogas scenario the supply of energy through gas networks remains high the carbon intensity of the energy delivered through these networks reduces significantly (through blue-, green hydrogen and biomethane and post-combustion CCS)[22] and reaches a decarbonization level of 89% (compared to the same energy supplied by unabated natural gas) in 2050 (Figure 10). If net negative emissions of methane-fired power generation (related to biomethane with CCS) were included the decarbonization level of the would reach 104% and thus ensure full decarbonization of the gaseous energy supply chain.

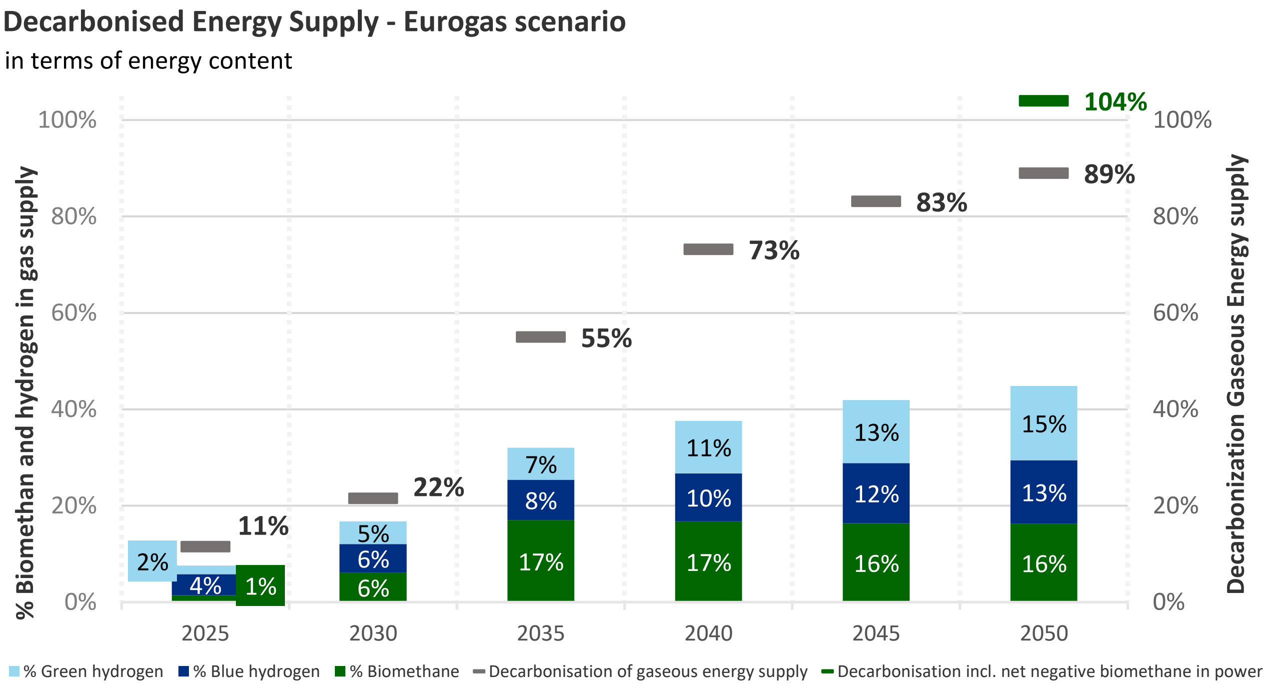


Figure 10 Decarbonization of gaseous energy supply in the Eurogas scenario[23]

Achieving these high shares of hydrogen, biomethane and the level of decarbonization depends on a rapid and sustained scaling up of biomass gasification and hydrogen production capacity by 5% per year until 2050. Similarly, as will be shown in Section 3.3, decarbonizing the remaining natural gas demand requires scale-up and significant deployment of CCS capacity.

3.1 Biomethane

Biomass constitutes the largest source of renewable energy in Europe providing more than 60% of total renewable energy consumption in 2017. Biomass can be used directly to produce heat and electricity but can also be converted into gaseous energy such as biomethane.

Biomethane is biogas originating from anaerobic digestion of biomass and upgraded to natural gas quality specifications so that it can be blended without restrictions in natural gas systems. Raw biogas consists of methane levels of 55 to 65% and CO_2 levels of 30 to 35% and smaller levels of other components and trace elements. As such, additional processing steps are required to assure network gas quality specifications are met, most notably CO_2 removal by water scrubbing and conditioning to remove sulphur components, siloxanes and other unwanted impurities. Also, network connections including

[22] Non-abated carbon emissions in other sectors are offset by negative emissions from biomethane and biomass, but are not accounted for in this overview of decarbonization

[23] The 2050 level of hydrogen supply in Eurogas scenario difference with Figure 9 due to rounding

measurement, quality control and compression are necessary steps before biomethane can be injected into the (natural) gas distribution or transmission network.

Alternatively, biomethane can be produced through gasification processes such as thermal gasification, super critical water gasification and plasma reactors. Gasification produces syngas consisting predominantly of hydrogen and carbon monoxide which can be further processed in a water-gas-shift reaction to convert CO to CO_2 and in a subsequent step called methanation to produce methane. This in turn can be fed into the natural gas system. Although promising technologies, biomass gasification is still under development and limited commercial endeavours have been made. The biomass gasification project GoBiGas in Gothenburg commissioned in 2013 (and decommissioned in 2018) was the world's first demonstration plant for large-scale production (20MW capacity) of biomethane.

Compared with anaerobic digestion, gasification can be easier scaled for larger production quantities. Innovative hybrid systems could see gasification added as next processing step to further utilize the residues from anaerobic digestion and maximize the energetic yields.

3.1.1 Biomethane uptake in scenarios

Eurogas and 1.5TECH have similar levels of biomethane demand in 2030 (~375 TWh or respectively 6% and 8% of total gas supply). By 2050, demand levels slightly diverge with Eurogas seeing 1008 TWh and 1.5TECH 900 TWh (Figure 11) in biomethane demand. All sectors use biomethane as it is blended into the natural gas grid. Electricity generation consumes most biomethane in both scenarios (respectively 33% and 24% or 336 TWh/year and 224 TWh/year). The biomethane fraction in natural gas is the same for all sectors as it is blended and spread evenly throughout the network.

Under 1.5TECH biomethane use in the manufacturing sector is higher than in the Eurogas scenario; a direct consequence of the overall methane use (i.e. the blend of biomethane and natural gas) in this sector being higher than under Eurogas. In the Eurogas scenario, the manufacturing sector is forecasted to shift to hydrogen instead of methane. The Eurogas scenario sees more methane use in buildings than under 1.5TECH resulting in a higher share of biomethane in this sector.

Section 4.3 will illustrate that 1.5TECH heavily relies on electricity to decarbonize the buildings sector. This requires strong subsidies to refurbish and convert buildings on time to allow such a high-level of electrification. In comparison, the Eurogas scenario's continued use of natural gas combined with biomethane allows for less strenuous and costly decarbonization efforts imposed to the buildings sector.

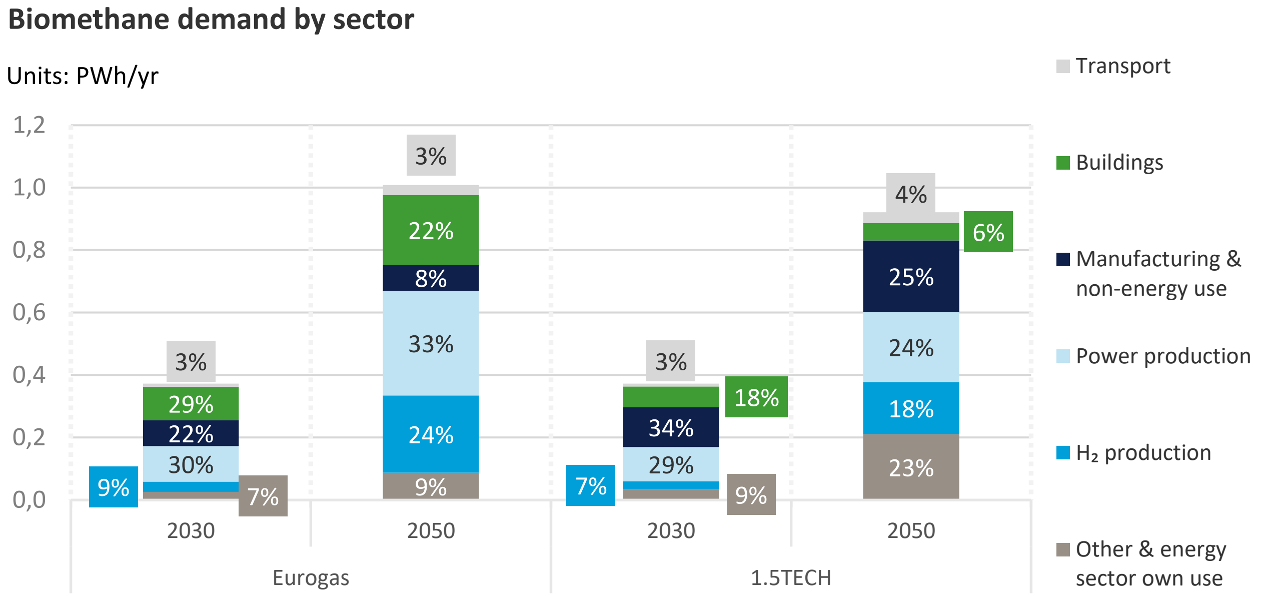


Figure 11 Biomethane demand by sector

In those sectors where CCS is applied, the use of biomass and biomethane creates net negative CO_2 emissions offsetting more than 100% of unabated emissions in the Eurogas scenario and around 95% of unabated emissions in 1.5TECH. The primary driver for this to happen is the CO_2 price: At around 100 euro per ton, CCS becomes a financially viable option. Starting at an average price of 110 euro per ton today[24], the learning effects makes unit cost of CCS drop to 59 euro per ton in 2050.

3.1.2 Biomass availability

Both scenarios foresee a growth in biomethane supply towards 2050 (see also Figure 8). Under the Eurogas scenario around 1000 TWh/yr is supplied in 2050, while biomethane production in 2050 under 1.5TECH is 928 TWh/year. We assume a 70% conversion efficiency. This would require respectively 1430 TWh/year and 1325 TWh/year of biomass feedstock, expressed in energy terms. Currently, the European production of biogas is approximately 200 TWh/year [9].

Traditionally, bioenergy is made from energy crops such as maize, which requires dedicated arable land ('first-generation'). As such, they may compete with food production. This can create pressures for other land to be used for farming, removing carbon sinks through potential deforestation and leading to more CO_2 accumulation in the atmosphere. Furthermore, soil acts as a carbon stock in the form of soil organic carbon (SOC); SOC is also key for maintaining land productivity by keeping soil structure intact. By not returning crop residues to the land, SOC levels may drop and risking desertification. From a sustainability perspective, it is important to take these impacts into account to ensure biofuel feedstocks are not crops that can compete with food and feed use.

Occasionally, food crops can be used when their goals as food have been met. For example, waste vegetable oil can be used as biofuel feedstock because it's no longer suitable for human consumption. In Art. 29 of RED, the European Union imposes criteria to ensure that biofuels are sustainably produced. On a high-level, these sustainability criteria check that the production of the feedstock does not happen on lands with a high biodiversity and high amount of carbon stock, and that the biofuel production itself leads to enough emissions savings by taking account of all emissions throughout the different steps in

[24] DNV GL (2019) Energy Transition Outlook.

the supply chain. Furthermore, additional criteria such as soil, water and air protection can be included. We refer to biomass that complies with such criteria as second-generation biomass.

Sustainable biofuels are thus produced from various non-food biomass types like wastes and residues. In this section, we report the findings from a literature study on their availability within the European Union [10]. For simplicity, we divide the feedstocks for second-generation biofuels in three categories:

1. **Agricultural** feedstock: Agricultural residues, crop residues, intermediate crops and manure residues
2. **Forestry** feedstock: Forestry residues, logging and wood cutting residues, and sometimes forestry related industries such as paper making.
3. **Others**: Includes municipal waste and /or industrial waste.

Literature reviewed included both academic papers as well as reports published by interest organizations, consultancies, and institutes (e.g. renewable energy research institutes). Only literature with clear definitions, an understandable and transparent approach, sufficient geographical coverage, detailed results etc. were used. Not all studies did expressly address the aforementioned sustainability criteria, but the criteria maintained in the studies we reviewed were generally strict. However, differences in the criteria maintained naturally exist between the studies, which also causes differences in results. Another reason for differences in the results was that some studies assume that all potential, sustainable biomass can be utilized while other studies assume that there are practical limitations to collect all available biomass (e.g. to collect and transport all residues from thinning and wood cutting).

This results from the 12 studies forming the basis for our assessment are in Figure 12 below.[25]

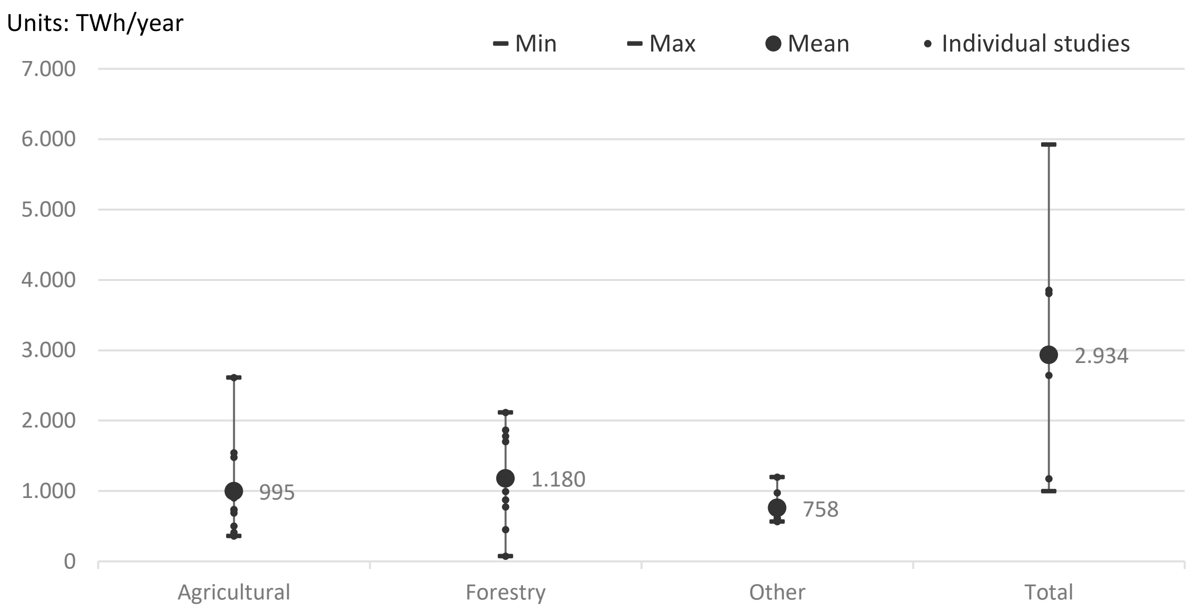


Figure 12 Biomass feedstock availability – for biomethane use - by category

Figure 12 shows that the variation between the different studies is large. The mean values are shown and add up to 2,934 TWh/year in 2050 over all three categories. The smaller dots display the results of the individual studies; not all studies provided an estimation of the available feedstocks in the three

[25] See references: [25] [32] [11] [29] [31] [30] [28] [26] [27] [34] [35] [36]

categories. Only four studies did. The range of available biomass goes from 1,000 TWh/year to almost 6,000 TWh/year, indicating that there's a lot of uncertainty in the values found in literature.

The total biomass, gasified, liquified and solid, required in the Eurogas scenario for all uses (biomethane use is 1430 TWh in 2050 as alluded to just above)- is nearly 3,400 TWh/year in 2050 (1.5TECH scenario requires 2,100 TWh by 2050), which is about 15% more than the average of the studies. There is little consensus in literature on whether the biomass availability potential may grow in the future; a moderate increase of about 16 to 18% per decade was historically observed in [11]. Until 2030 such a growth rate may be achieved, while the growth potential after 2030 is more uncertain.

The same paper [11] also provides values for individual countries of which the sum is near the median value of all studies. The breakdown by country is provided in Figure 13 below. In general, field residues potentials are especially high in countries with a large agricultural area. Nordic countries with well-developed forest industries have large potential for biomass from forestry as well as industry (e.g. waste wood from wood processing and industrial black liquors).

With regard to solid biomass availability, we note that currently Europe is a net solid biomass importer, importing 38.5 million ton of biomass in 2018 (and exporting 33.7 million ton). [12] In our ETO 2019 report (pg. 151) we found that as inefficient use of biomass is replaced by more efficient uses (and availability is expanded with second and third generation supplies) the world is able to sustainably use and produce liquid and gaseous biofuels. We diligently considered possible global resource limitations in the ETO2019 scenario, and found its biomass use sustainable. The biomass used in Eurogas and 1.5TECH scenarios are similarly found available and sustainable.

The assessment for biomethane feedstock focused solely on second-generation biomass; we did not include third-generation biomass potential or so-called algal biomass such as seaweed. Studies that estimate the potential for third-generation biomass are sparse, but algae can produce far more biofuels per hectare compared land based sources. [13] Although algae are frequently brought in connection with biodiesel due to more extensive research in this field, it is possible to produce biogas through anaerobic digestion of algae biomass.

Units: TWh/year

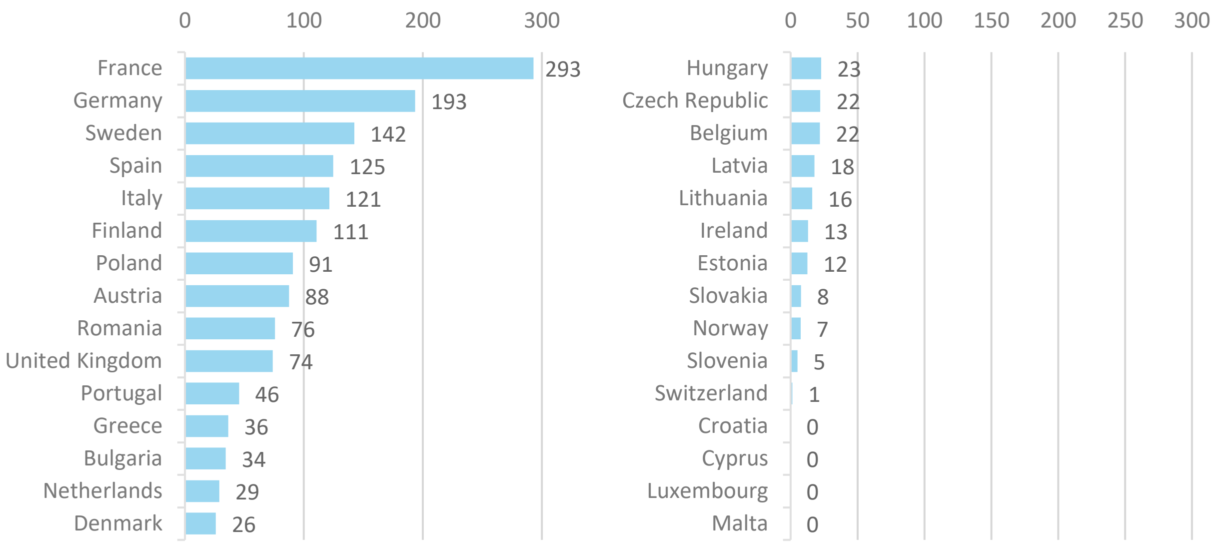


Figure 13 Current biomass feedstock availability by country (EU plus Norway, Switzerland)

3.2 Hydrogen uptake & development

Even though hydrogen is currently widely used as a feedstock in the (petro) chemical industry, it plays virtually no role as an *energy carrier*. According to the International Energy Agency, nearly 74 million tons (>2,400 TWh) of hydrogen was produced globally in 2018: 38.2 million ton (~1,300 TWh) for refining, 31.5 million ton (~1,000 TWh) for ammonia and 4.2 million ton (140 TWh) for other purposes. [14]

Today's hydrogen originates primarily from reforming natural gas and gasification of residues from crude oil distillation in refineries and to a lesser extent as a by-product of sodium chlorate and chlor-alkali processes using electrolysis technology. Hydrogen is either directly produced on-site of the production facility of the end-product or transmitted over a dedicated pipeline network supplied by methane reforming plants.

Indeed, dedicated hydrogen networks exist already in several European industrial regions such as Antwerp-Rotterdam in Belgium (~600 km) and the Netherlands (~240 km), the north of France (~300 km) and several areas in Germany (~400 km). Furthermore, expectations about imminent cost reductions in water electrolysis technology coupled with increase in variable renewable electricity generation from sources such as solar and wind have taken hydrogen to the front stage of the European energy policy debate as the clean, versatile energy carrier of the future.

Europe is not in this alone: Japan's energy policy has been direct to become the world's first "hydrogen society". Japan's industrial conglomerates are actively involved in hydrogen development projects. Recently, Kawasaki Heavy Industries announced the development of a hydrogen liquefaction plant to export hydrogen from Australia to Japan by vessel.

Indeed, Australia is another hotspot for hydrogen development. Its national hydrogen strategy was released in November 2019 and aims at making Australia the world's top exporter of hydrogen. Both net zero scenarios see an increasing role for hydrogen as an energy carrier in Europe as well, also considering national strategies developing in Germany, the Netherlands or Portugal, whilst the EU is expected to publish a Hydrogen strategy in parallel to its industrial strategy.

3.2.1 Hydrogen uptake in scenarios

Currently decarbonized hydrogen can most realistically be produced (both technically and at scale) in two ways through water electrolysis and through fossil fuel reforming with CCS.[26]

Water electrolysis splits water into oxygen and hydrogen by applying an electric current. Alkaline electrolysis and polymer electrolyte membrane (PEM) electrolysis are two technologies that have reached the greatest maturity with module sizes up to 3-4 MW commercially available. Alkaline electrolysis equipment is currently less expensive than PEM technology. However, PEM benefits from producing hydrogen at higher pressures limiting the need for expensive compression and has greater dynamic response capabilities. Next to Alkaline and PEM, solid oxide electrolysis is a promising technology but still under development and not commercially available. Solid oxide electrolysis is expected to deliver higher conversion efficiencies as the higher temperatures under which it operates can decrease the voltage required for electrolysis.

Combining electrolysis with renewable energy sources of electricity can produce renewable or 'green' hydrogen. Further, it may limit curtailment of variable sources such as wind and solar if rapidly responding producers can utilize this excess electrical power and store the produced hydrogen. The cost of green hydrogen is determined by the power price duration curve and the running hours. At lower running hours, the capital and fixed operating costs determine the cost of green hydrogen, while at higher running hours the cost is determined more and more by the electricity price.

When plotting hydrogen production costs through electrolysis against running hours, there's a steep decline in costs until approximately 2,000 hours after which hydrogen production costs further, but slowly, decline to a minimum at the optimal running hours. Depending on electricity prices, the optimal amount of running hours is typically between 3,000 and 6,000 hours per year ([14] and [15]). After reaching the minimum, the production costs slowly rise again as higher priced electricity is required to feed the electrolyser.

Secondly, hydrogen can be produced by converting fossil fuels such as natural gas to hydrogen. Presently, steam methane reforming (SMR) is a well-proven and broadly applied method to produce hydrogen. To achieve decarbonization, the CO_2 emitted must be captured and stored or used as a feedstock in the industry. CCS technology is a viable technology today and is applied in several places throughout the world, mostly for enhancing oil recovery by reinjecting CO2 into the reservoir. Next to SMR, autothermal reforming (ATR) can be used to convert natural gas to hydrogen. The advantage of ATR over SMR is that it allows for a higher carbon capture rate (95%) compared to SMR (60-70%).

The path towards increasing levels of hydrogen production and uptake differs between the scenarios. Where the Eurogas scenario sees both hydrogen production through electrolysis and methane reforming in combination with CCS already in 2030, by then 1.5TECH only sees methane reforming coupled with CCS. Indeed, blue hydrogen is the leading source for producing decarbonized hydrogen through 2030 in both scenarios (Figure 15).

During the mid-2030's a rapid increase in electrolysis occurs at an CAGR of 33% in both scenarios, causing the balance to shift from blue to green hydrogen towards 2050. By then, 54% of hydrogen is produced by electrolysis under Eurogas against 68% under 1.5TECH. The significantly higher share of wind and solar generated electricity and subsequently more frequent curtailment risk is the main reason

[26] Pyrolysis is considered a possible decarbonization technology for the (near) future, but currently it has only been proven at laboratory scale and as such not included in this section or as a technology in either one of the scenarios.

why the 1.5TECH scenario sees higher volumes of electrolysis and green hydrogen. In 1.5TECH, electrolysis sees a much larger growth rate towards 2050 than methane reforming with CCS.

In the Eurogas scenario manufacturing leads the hydrogen uptake until 2030. Manufacturing sector's head-start in the uptake of hydrogen is supported by a mix of subsidies, increasing carbon prices and cost reductions in carbon capture and storage. Figure 14 below shows how the cost of carbon capture and storage declines under the scenarios. The cost reductions result from the accumulated CCS capacity build-up and associated learning effects in the capture part of the CCS technology, as storage and transport are deemed mature with limited cost learning feasible

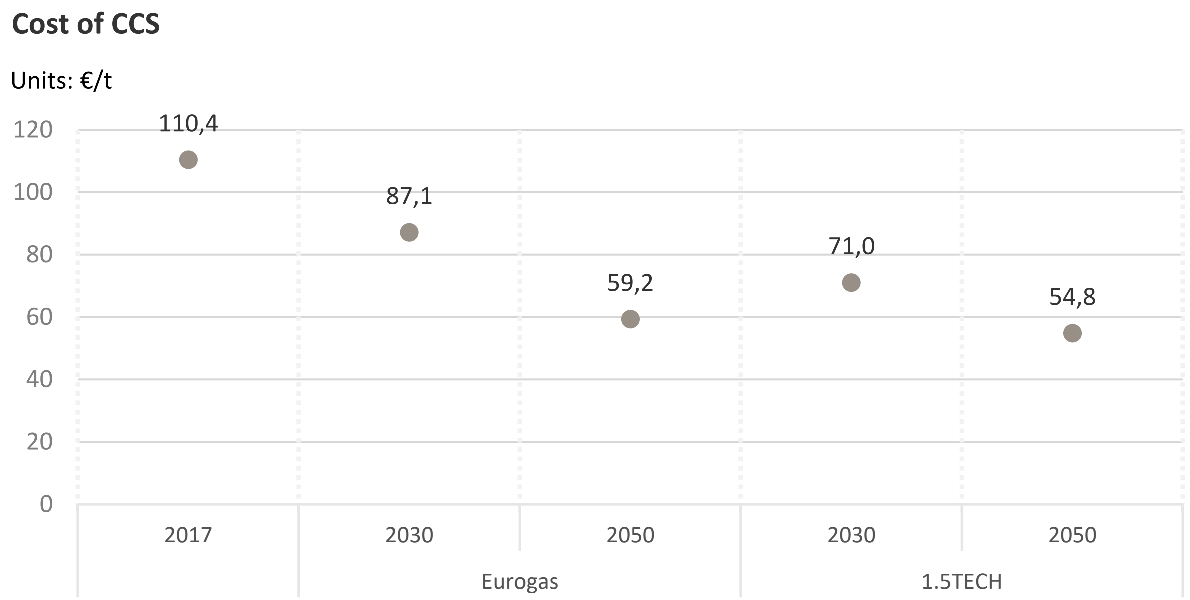


Figure 14 Cost development of carbon capture and storage

The 1.5TECH scenario sees increasing hydrogen demand in the manufacturing and buildings sectors, but to absolute levels that are about half of the uptake in the Eurogas scenario. Finally, hydrogen in transport becomes a relatively minor option in both scenarios, albeit at similar levels.

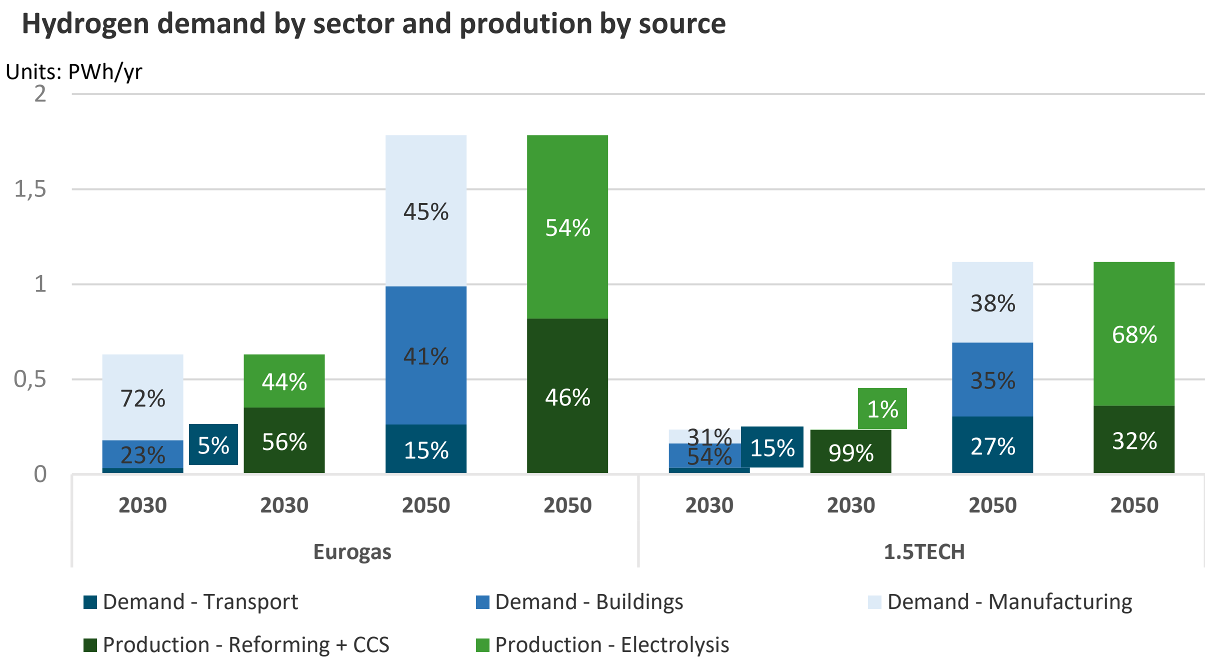


Figure 15 Hydrogen production by source and demand by sector

3.2.2 Hydrogen supply in the energy value chain

The hydrogen uptake discussed above will be supplied both through dedicated hydrogen pipeline supplying pure hydrogen to end consumers and hydrogen blended with other gaseous fuels in the gas networks. The use of existing, re-dedicated networks to transport decarbonized hydrogen instantly removes carbon dioxide emissions from all gas users connected to that network. This makes it possible to decarbonize many small and geographically dispersed emitters using existing and mostly paid-for, reliable and well-distributed, large-scale infrastructure.

All demand sectors can be supplied by both options depending on a country's policy to either introduce blending first or to immediately switch to pure hydrogen. Thus, separate networks (methane, blended or dedicated hydrogen) can be available for each sector of demand. In the model we have assumed a maximum blending ratio of 20% hydrogen a level at which most end use equipment for residential heating in the forecasted period can be used with only minor adjustments[27]. [16]

When any sector has a hydrogen fraction of less than 20% in the total gas mix, this can be delivered as a blend through the existing gas networks. In this way, smaller amounts of hydrogen can be provided to end users to achieve a phased in decarbonization at minimal cost whilst assuring a secure energy supply. In case hydrogen production reaches more than 20%, supply through dedicated grids complements the blending option. For instance, hydrogen for the buildings sector would initially be supplied through blending. However, dedicated supply for (parts of) this sector materializes after 2030, as the sector as such supports a hydrogen demand of more than 20%. By then, cost of hydrogen heating technology is expected to be at parity with natural gas installations. In Section 4.3, the energy supply to buildings and hydrogen's part in it is discussed in more detail.

[27] For some specific industrial uses, particularly legacy gas turbines for power generation, some industrial heating equipment and feedstock processes, blending tolerances are likely to be lower and a case by case assessment is required.

Figure 16 shows that under the Eurogas scenario, hydrogen is supplied to end consumers by 2030 in roughly similar volumes of blended hydrogen and hydrogen through dedicated pipelines ('pure hydrogen'). In the 1.5TECH scenario hydrogen supply through dedicated pipelines is considerably smaller than hydrogen supply through a blend with natural gas until 2030. Between 2030 and 2050, the balance clearly shifts to hydrogen supplied through dedicated pipelines in both scenarios. This development—dedicated hydrogen infrastructure—is triggered by the manufacturing sector's leading role in decarbonized hydrogen demand. Dedicated hydrogen infrastructure connecting industrial clusters is established through retrofitting existing gas pipelines and investments in new infrastructure. Of the two, retrofitting of existing gas pipelines is the most common as it is the most cost-efficient option.

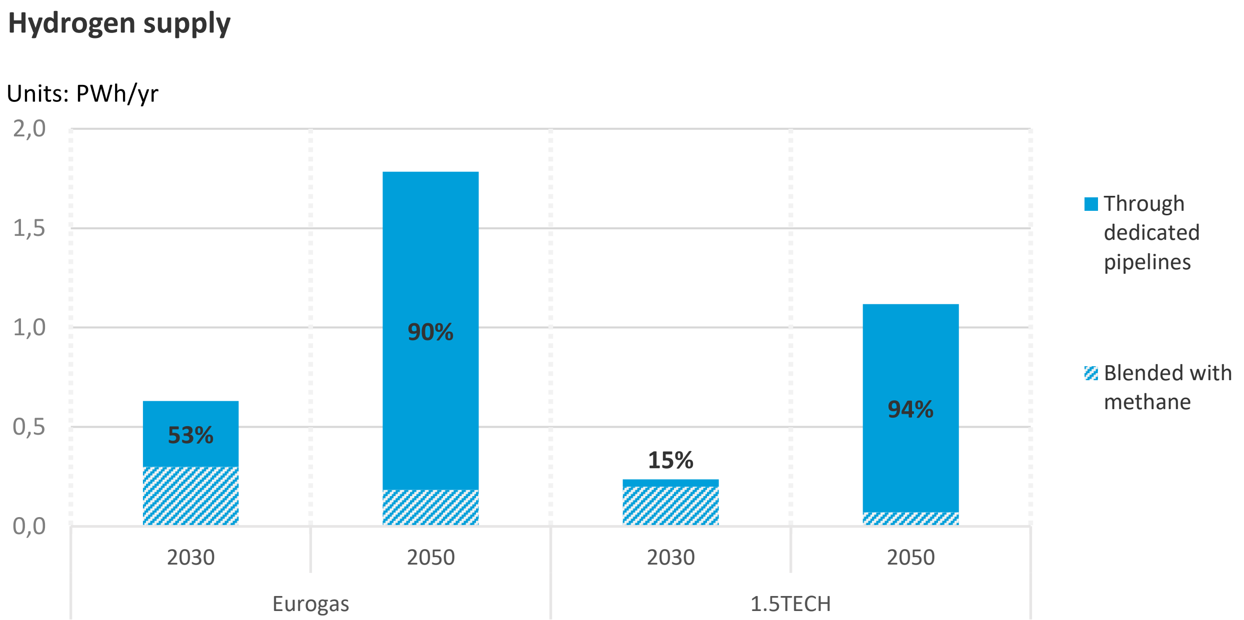


Figure 16 Shares of hydrogen supply through dedicated pipelines and blended with methane

Figure 17 provides more insights into the development of hydrogen networks under the Eurogas scenario. Up to 2030, hydrogen is transported roughly evenly through new dedicated transmission pipelines to supply dedicated industrial off-takers and through blends with other gaseous fuels. After 2030, as the demand for methane declines the majority of hydrogen transmission pipelines stems from upgraded and re-purposed pipelines as natural gas transmission capacity is underutilised.

This increases the hydrogen transmission capacity by 9% per year between 2030 and 2050. By 2050, 20% of natural gas grids are converted to hydrogen. The alternative to conversion would be for these pipelines to be decommissioned and replaced by new built hydrogen pipelines. Decommissioning requires complete removal of gas pipelines which is estimated to cost around 30% of new builds. Repurposing these pipelines for hydrogen transport therefore saves these costs.

In the UK, the Netherlands and Germany, gas system operators are working to convert existing gas networks to hydrogen. The "H21 North of England" project in the UK foresees to incrementally convert, in six phases executed between 2028 to 2050, large parts of the UK to hydrogen [17]. In the Netherlands plans are developed, among others, to connect the largest industrial clusters, other users and interconnections through a so-called hydrogen backbone mainly through repurposing existing infrastructure [18]. Recently, the German transmission system operators launched a plan for a national hydrogen transmission network measuring 5,900 km and consisting for more than 90% of the existing gas network. The network will be used to transport hydrogen produced in the north of Germany to industrial clusters in the west and south. [19]

In the medium term there is very limited need for dedicated distribution grids as most of the hydrogen is blended in existing methane supply. Although some dedicated hydrogen distribution systems are constructed post-2030, the majority is converted from methane (i.e. biomethane and natural gas) to hydrogen.

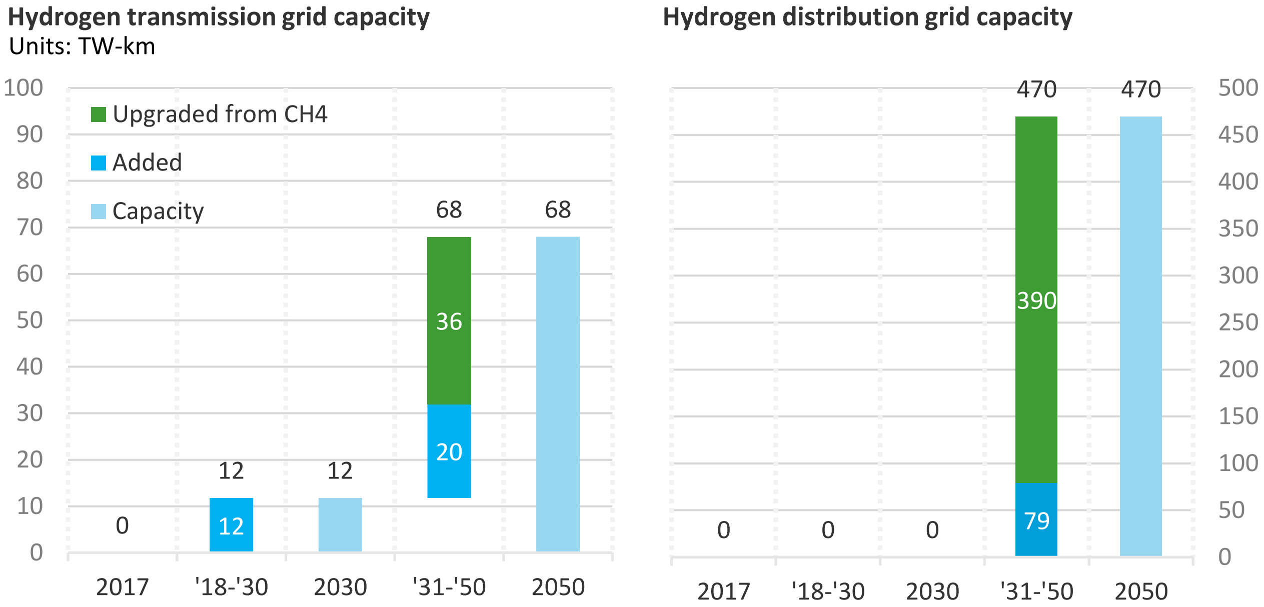


Figure 17 Hydrogen grid developments in the Eurogas scenario[28]

[28] The unit of this graph is "TW-km" a unit that we developed for the Energy Transition Model to align both the current EU gas network length and capacity to costs associated to change the network, as these are the two primary cost drivers in pipeline (transmission and distribution) development and retrofit.

Textbox 2   Levelized cost of imported hydrogen from renewable electricity

The ETO model has no functionality to allow for hydrogen imports from outside Europe. It is limited to natural gas being transported to Europe where blue hydrogen is produced. Furthermore, it predicts that sufficient variable renewable electricity is installed in Europe to produce green hydrogen. As this study is based upon the ETOM, neither scenario includes hydrogen imports as an option.

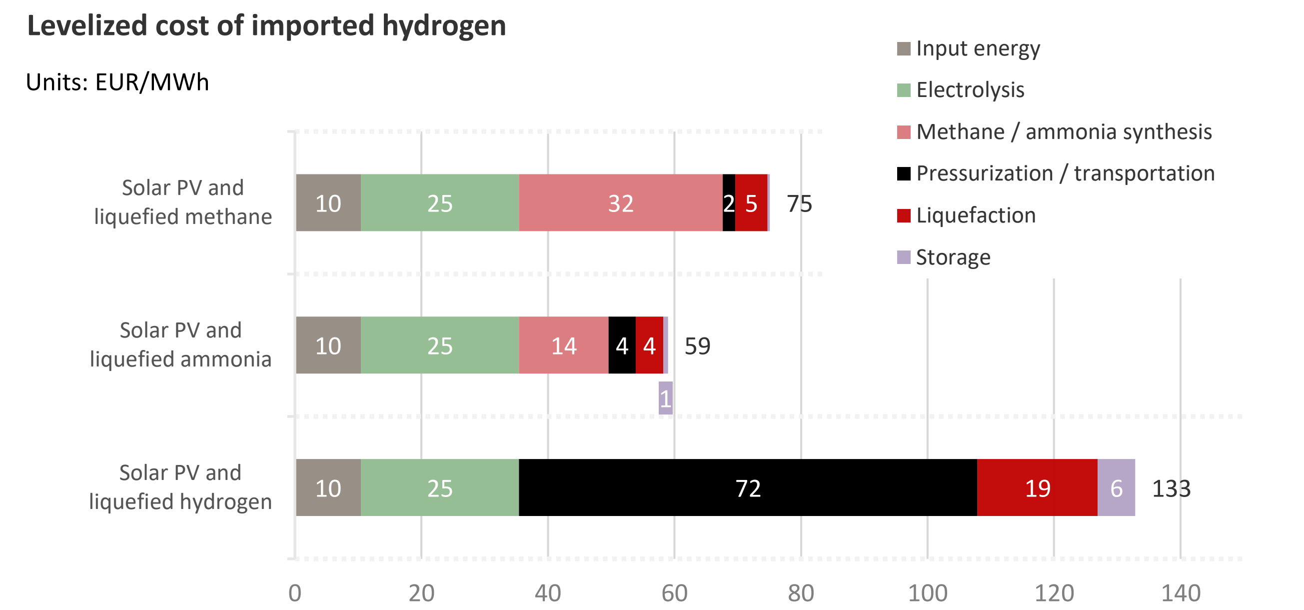
Nevertheless, hydrogen can be produced in other regions where operational costs to generate renewable electricity are significantly lower. The produced wind or solar electricity can subsequently be converted into hydrogen through electrolysis, liquified and transported by ship to Europe. Once at its destination, the liquid hydrogen can be stored in tanks. We provide an estimation of the levelized cost of imported hydrogen using three options (based on [20]):

4. Liquefied methane
5. Liquefied ammonia
6. Liquefied hydrogen

Upon arrival in Europe, the liquid is regasified in case of hydrogen and methane. Ammonia is converted into hydrogen and nitrogen.

Our analysis suggests that imported hydrogen made from renewable electricity is not expected to become competitive compared to locally produced hydrogen which will cost 11.2 euro/MWh in 2050. For the calculation we assume electricity produced through solar PV in a favourable location such as the Middle East. We estimate the levelized cost of electricity production in this region in the year 2050 at 10 euro/MWh (compared to X in 2017), or about a third of the average solar PV cost in Europe (compare Figure 34). We assume that hydrogen produced through electrolysis is transported by pipeline over a distance of 100 km to a location where it is liquefied. Further, a sailing distance of approximately 12,000 km – equivalent to the journey from Oman to Rotterdam – is taken.

The chart below shows the levelized costs of the three different liquid hydrogen carriers for the year 2050. It indicates that using liquid ammonia is the least cost option at 59 EUR/MWh. As shown in the breakdown below, the costs along the value chain associated with ammonia are lower in virtually all parts compared to the other two carriers. Notably, the cost of transportation is a small part of the total costs, suggesting that solar PV in regions closer to Europe may not result in large cost reductions.



In order to become competitive with locally produced hydrogen, further cost savings need to be realized, particularly in conversion technologies. Our analysis underlying the results shown above, assumes cost learning for electrolysis towards 2050, but not for the other technologies as these are relatively mature.

Nevertheless, we did not analyse so-called Liquid Organic Hydrogen Carriers (LOHCs). LOHCs are based on organic compounds to which hydrogen can be chemically bounded such that it forms a liquid which can be transported. At the unloading site, hydrogen is separated from the LOHCs, which can then be reused. It is a promising technology but still in its infancy as its technical feasibility has only been proved at smaller scales (technology readiness level is at 2-3). LOHC's may therefore bring the necessary technological innovation to support competitive liquid hydrogen imports.

3.3 Role of CCS in decarbonization of gas

3.3.1 Uptake of CCS in the two scenarios

Carbon capture and storage refers to sequestering carbon atoms, usually as CO_2 molecules, from emitters and storing them in depleted oil and/or gas fields including their transportation to the storage site. We allow for the application of CCS at emission sources directly (post-combustion CCS) and as part of producing 'blue hydrogen' (pre-combustion CCS). Both largely assure that no greenhouse gases are emitted when using fossil fuels as between 70 and 97% of emissions is captured and stored

The ETO model assumption is 95% capture and storage rate for both scenarios, as this is the uptake needed to make CCS a credible decarbonization option. Moreover, even higher decarbonization rates are already achieved in laboratories. When hydrocarbons from biogenic sources are used, negative greenhouse gas emissions occur, for example when biomethane is used in a gas-fired powerplant, equipped with CO_2-capture. This process is frequently referred to as Bio-Energy with Carbon Capture Storage (BECCS).

In both scenarios, CCS is established as a pre-requisite for decarbonization and is used for large scale applications, i.e. in electricity generation and manufacturing (Figure 18). In 2050, CCS uptake in the Eurogas scenario is 17% higher, but on a cumulative basis over the period towards 2050 the deployment of CCS is 15% lower than under 1.5TECH, due to slower uptick of carbon prices in the Eurogas scenario.

With a larger overall share of gas, the Eurogas scenario decarbonizes the energy system with a lower cumulative CCS deployment towards 2050. Nevertheless, to achieve full decarbonization of Europe's energy system, an annual growth rate in CCS between 2020 and 2050 is as high as 20% in both scenarios.[29]

Based on IOGP estimates the CO_2 storage capacity in Europe (including Norway) is approximately 300 $GtCO_2$ [21] disregarding potential limitations for CCS uptake stemming from restrictive policies. The flagship CCS projects in Europe is the storage in the Sleipner formation in Norway. First injection of CO_2 started in 1996. Nowadays annually approximately 1 Million tonne CO_2 is injected in the formation, with 20 million tonne stored to date. The total capacity of the formation is estimated to be well over 1 $GtCO_2$.

The accumulative carbon storing in in both scenarios uses only about 5% of the available storage capacity leaving around 300 years of storage left in 2050. When taking account of restricted policies, the European storage capacity is estimated at 134 GtCO2. Some countries have introduced bans in national legislations by prohibiting CO_2 storage for a certain time period, location (e.g. onshore) or limiting the stored amount until the technology is more proven [21]. In this situation both scenarios use about 12% of available storage capacity. Extrapolating the annual CO_2 storage in 2050 this would mean that about 120 years of storage is left in 2050.

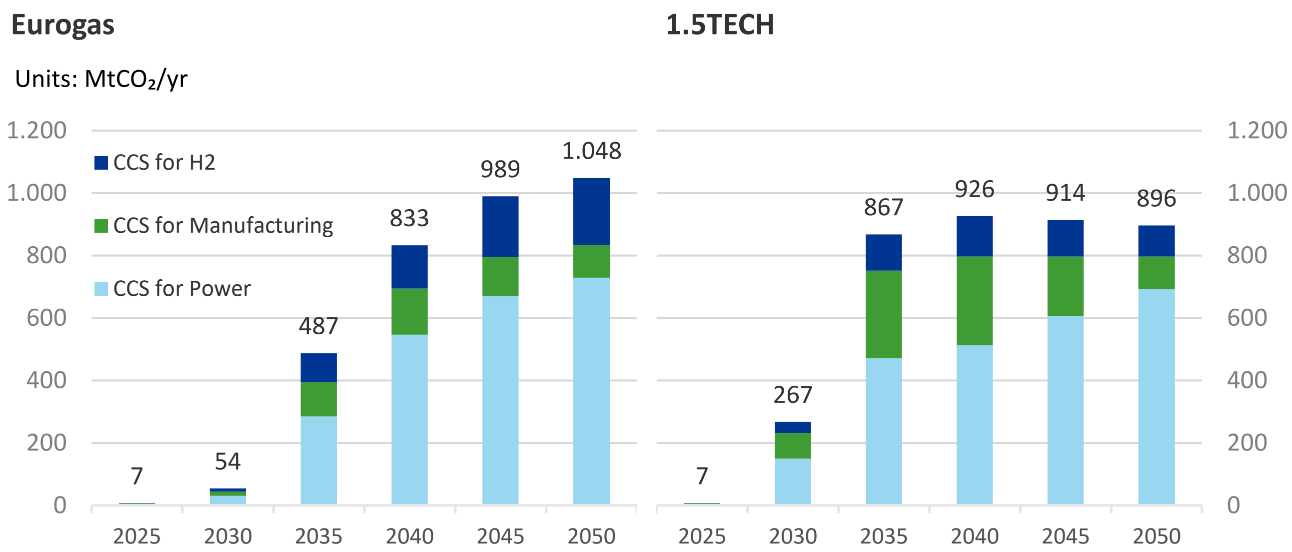


Figure 18 Overall CCS uptake in the Eurogas and 1.5TECH scenarios

Looking to manufacturing[30] specifically (**Error! Reference source not found.**), the analysis shows that CCS is indispensable for decarbonizing the manufacturing sector in both scenarios. However, higher carbon pricing in 1.5TECH supports an earlier uptake of CCS. In the manufacturing sector (especially in the 1.5TECH scenario), electrification becomes more important over time and therefore the CCS uptake shifts from direct process emissions towards capturing the emissions from power generation. These two trends cause the use of CCS in the manufacturing sector to steeply peak, followed by a sharp decline as

[29] 21% per year in Eurogas and 20% per year in 1.5TECH.

[30] Average running hours for gas fired power plants will not decline, but increase as gas used for firm capacity will increase five-fold to 2040. Our analysis shows an increase in variability due to PV and Wind generation which is balanced by various factors (supply and demand side managed). The power stations involved are mostly low (capital) cost generators. Thus, CCS will be well placed to decarbonize gas fired power stations.

facilities built are either no longer needed or retrofitted to accommodate emissions from other (power) generation.

By contrast, in the Eurogas scenario, a slower increase in the carbon prices results in a slower and more gradual build-up of CCS capacity in manufacturing. CCS's slow decreasing uptake in the manufacturing sector in the longer term is partly due the deployment of blue hydrogen which avoids the need for CCS at emission sources. Total CCS capacity for manufacturing in Eurogas only reaches half that of 1.5TECH. Yearly sectoral growth rates are 16% for the period 2020 to 2050 in both scenarios. For the next 20 years (2020-2040), the yearly growth rate is 28% in the Eurogas scenario and 31% for 1.5TECH.

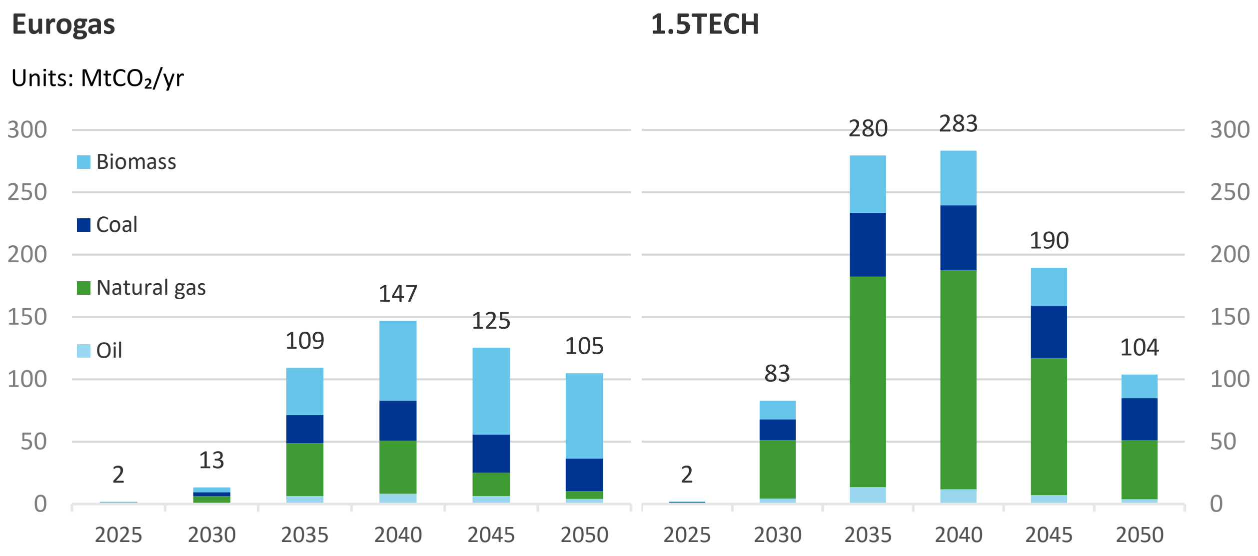


Figure 19 Manufacturing sector direct CO_2 emissions captured

3.3.2 CCS in the energy value chain

The concept of CCS embeds the capture of CO_2 which is transported to a storage location. These three elements, i.e. capture, transport and storage, can be placed at different positions in the energy value chain. In our model we have identified the need for CCS in order to mitigate carbon emissions to the atmosphere. As with all value chains the optimal position for CO_2 capture – i.e. if the capture should be placed at the extraction site or at the end-user site – depends on local circumstances.

Carbon Storage

To mitigate the effects of CO_2 in the atmosphere, permanent storage of CO_2 is needed. Usually injection into geological formations is considered. Various options are available, ranging from depleted oil and gas fields to deep saline aquifers. The former has the advantage that the existing infrastructure could be reused. The latter has the largest storage potential, which is beneficial as the efficiency of CO_2 storage is enhanced if a few large storages are filled, rather than multiple smaller storages. In addition, onshore fields may encounter public concerns when used for CO_2 storage. It is therefore likely that CO_2 storage in the EU will take place primarily offshore.

Alternatively, CO_2 could be reused and stored in other materials. This concept is referred to as Carbon Capture and Utilisation (CCU). For example, CO_2 mineralisation can be used in the production of novel construction materials. Other technologies are developed that use CO_2 to produce chemicals and fuels such as urea-based fertilizers or methanol. However, the abatement effect for these CCU options can only be quantified through full lifecycle analyses.

The location of the storage site is an important parameter in the optimisation of the value chain. As indicated, we assume that the underground storage is offshore and utilisation of CO_2 is possible in selected industries, mainly located in large chemical clusters.

Carbon Capture

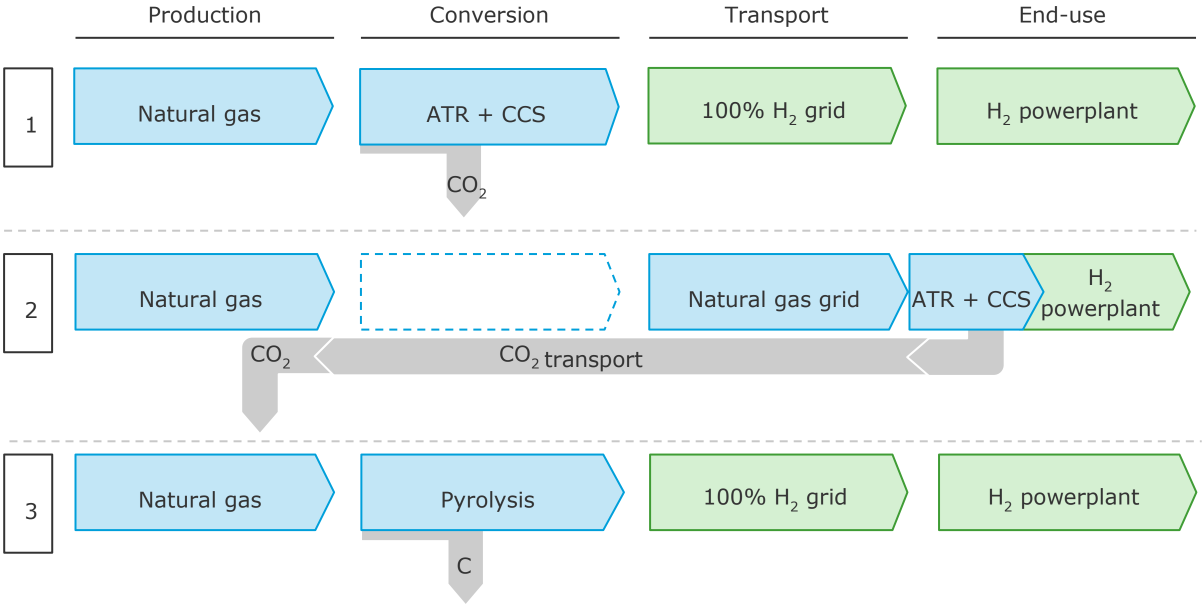
The capture process is generally the largest cost component. Post-combustion, the costs are mainly dominated by the concentration of the CO_2 in flue gases. The higher the concentration, for example in pre-combustion ATR, the lower the capture costs. The advantage of hydrogen production from natural gas with CCS ('blue hydrogen') is that the CO_2 stream resulting from the process is significantly purer compared with post-combustion CCS. High purity CO_2 streams are needed for reusing it in chemical processes.

Alternatively, pyrolysis is considered as a technology to split methane into hydrogen and carbon. Currently, there are several pyrolytic reactors under development by different companies or research groups. The majority of products are at R&D or pilot scale, but some companies have successfully developed commercially available reactors. For example, Monolith Materials has developed a plasma reactor that is ready for an early market entry of the generated hydrogen and carbon products [22]. The process is highly energy intensive. Different solutions have been investigated and tested, ranging from molten salt reactors to concentrated solar power.

On the economics, the business case for pyrolysis is strongly related to the added value of the produced carbon. It is estimated that the cost of hydrogen generated by pyrolysis processes goes from 190 EUR/MWh down to 26 EUR/MWh, depending on different variables such as the selling price of the generated carbon. Black carbon, graphite, graphene, carbon nanotubes, carbon fibres or needle coke are some of the different commercialisation possibilities for carbon. The price of the different sub-products will depend on the quality of the obtained carbon structures and the evolution of their own applications and markets [22]. However, at this stage the technology is still in low technology readiness levels, which makes it difficult to compare it to more mature pre- and post-combustion capture of CO_2.

Textbox 3 Position of CCS in the value chain

The illustration below provides three examples to indicate the position of the capture in the value chain and explore the different options for transporting the CO2 and natural gas or hydrogen. For simplicity we assume that the hydrogen is used for power generation in a powerplant.[31] In the first value chain, the capture from an ATR is placed at the extraction site of natural gas ('well head') alleviating the need for CO_2 transport. The second value chain shows the application of CCS at the end-user ('burner tip'). To store or use sequestered CO2, transport is required. Finally, the third value chain shows the



application of pyrolysis at the extraction site. As pyrolysis results in hydrogen and solid carbon, no CO_2 transport is required.

Carbon Transport

For connecting capture sites to storage sites, transport of CO_2 is required. Based on existing and planned projects in Europe, the main options are transport by pipeline or shipping. Repurposing offshore infrastructure to transport CO_2 to depleted oil and gas fields or saline aquifers suitable for CO_2 storage can help to avoid installing new offshore infrastructure but depends on the condition of the assets. Reusing offshore oil and gas pipelines to transport CO_2 may represent 1 to 10% of the cost of building a new CO_2 pipeline, where offshore pipelines costs can vary between 2 to 29 EUR/tCO_2 for transport over 10 to 1500 km respectively. Costs for ship transport range between 10 and 20 EUR/tCO_2. Shipping is preferred for smaller volumes and longer distances [21]. As an example the H21 North of England project [23] estimates the costs for a CO_2 pipeline itself between 1.6 – 3.0 million EUR/km for transport systems of 2827 ton CO_2/hr.[32]

[31] Different options for end use are available such as fuel cells or boiler where both the power and heat are produced.
[32] 581 MGBP/215km for 22inch or 1204 MGBP/845km for 30 inch.

The optimal configuration for a CCS value chain is tailor made and depends on several interconnected parameters, such as available storage locations, yearly CO_2 volumes and profiles, end-user locations and system integration aspects. A case by case analysis would be preferred to find the optimum, However, when considering these aspects, there are two primary arguments why capture is preferred at the end-user site and not at the extraction site:

1. Storage is either offshore or as reuse of CO_2 in chemical clusters. These same clusters are also potential capture sites, e.g. for hydrogen production via SMR or ATR. System integration is therefore better when capture is placed in chemical clusters as opposed to splitting the natural gas at the offshore extraction site. In the industry clusters, different flue gas streams could benefit from the capture plants. For example, captured CO_2 can be used in chemical processes (CCU) or multiple combustion flue gas streams can use a single capture plant. The capture plants must then be connected to a CO_2 infrastructure which transports the CO_2 to the offshore geological formations or to nearby chemical plants that use the CO_2 in their processes.
2. Large scale storage is preferred in offshore saline aquifers, which would require CO_2 infrastructure in both cases. In the case of capture at the extraction site, an offshore pipeline is needed from the gas field to the saline aquifers. In the case of capture at the end user a CO_2 pipeline system is needed from the chemical cluster to the offshore aquifers.

4 FACILITATING DECARBONIZED ENERGY USE

Naturally demand from end-users determines whether, and in what form or shape, decarbonized alternatives to their current energy supply will sufficiently be scaled up to deliver net zero carbon emissions for the economy as a whole.

As outlined in chapter two, decarbonization in the Eurogas scenario depends less on rapid electrification (and infrastructure CAPEX and supportive financial stimulus) than the 1.5TECH scenario. This is also visible in Figure 20 with the energy demand from different sectors in 2050. Overall energy demand declines in both scenarios through efficiency gains in the manufacturing and transport sector. However, in 1.5TECH electrification reduces overall energy demand by an additional 10% (14.550 TWh/yr) in comparison to the Eurogas scenario through even higher shares of VRES generation (no energy carrier conversion losses) and extensive electrification in the building sector (with heat-pumps being more efficient than gas-heating within a certain temperature range).

An important side effect of increased electrification is seen in the energy demand from "Other sectors" which for the 1.5TECH scenario slightly increases versus 2017 levels. As the 1.5TECH pathway will need a more extensive expansion of the electricity grid the energy sectors own use increase by 66% (770 TWh) compared to 2017 levels as a result of the losses in power transportation. The Eurogas scenario sees an increase in the energy sector own use by 13% (140 TWh) compared to 2017, as a result of less extensive electrification and the continued use the gas network as a more efficient way to deliver energy to customers.

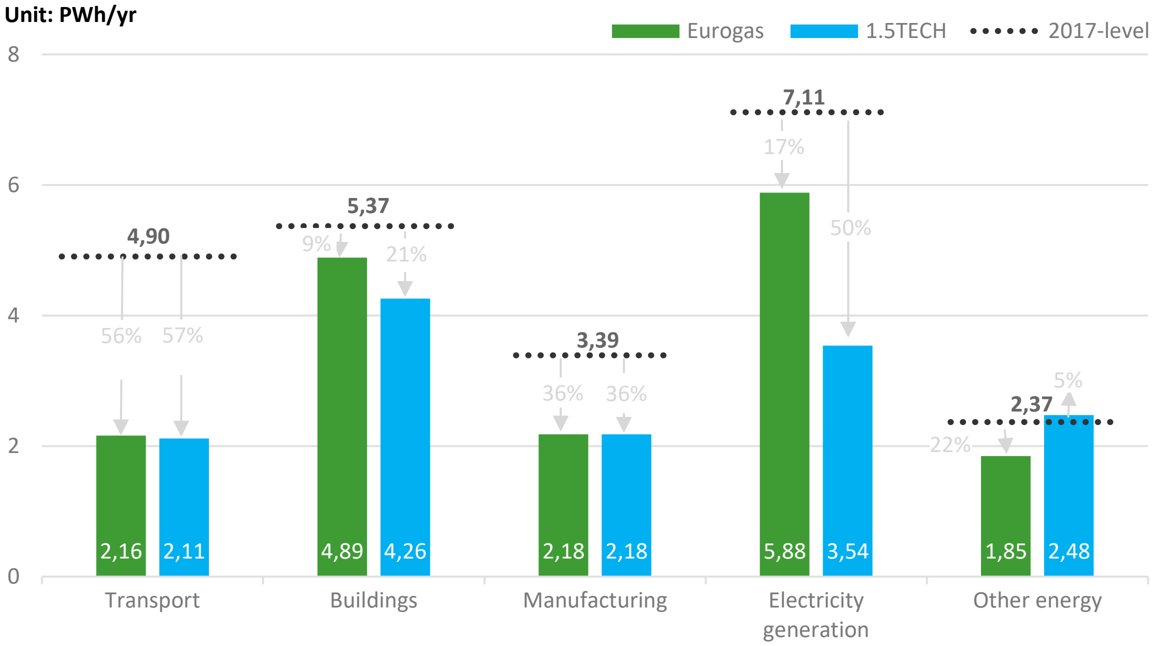


Figure 20 Energy demand per sector in 2050 for Eurogas and 1.5TECH scenario[33]

In all scenarios all sectors need extensive decarbonization efforts to achieve the targeted emissions reduction. Carbon pricing is applied equally as a burden in all sectors (Appendix C for price developments). By contrast, incentives (subsidies) are applied sector specific.

[33] "Other energy" include emissions from non-energy use, H_2 production, energy sector own use, and other.

Sectors that go beyond full decarbonization by using renewable biomass fuels and capturing CO_2 assure the 100% decarbonization of the energy system. This assures the net. negative overall ambition in both scenarios in 2050. This occurs in both scenarios through net negative emissions from biomass and biomethane in manufacturing and electricity generation.

In the Eurogas scenario net negative emissions make up for remaining emissions in transport and buildings. It means that despite higher demand for energy in the transport and building sector the emissions associated are offset due to the use of biomethane and post-combustion CCS in other sectors. 1.5TECH reduces emissions almost evenly across all sectors, following a more "all of the above" approach across the economy. Figure 21 below provides the emissions reduction per sector and scenario.

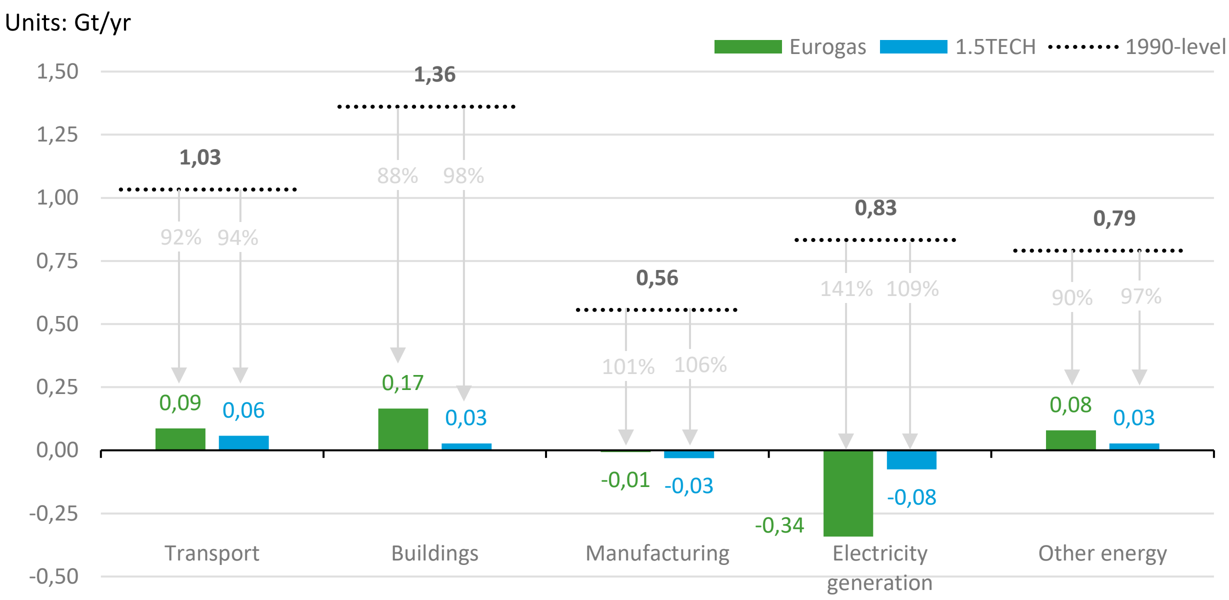


Figure 21 Sectoral CO_2 emissions in 2050 for Eurogas and 1.5TECH (excl. international aviation & maritime, land use changes)[34]

Although each scenario sees its own distinct decarbonization pathway similarities can be observed.

- Electricity generation and manufacturing sector decarbonization depends on CCS technology and infrastructure build-up.
- Biomass second generation biomethane are key pillars of decarbonization and crucial for net negative emissions.
- The transport sector follows similar pathways of electrification of the road transport (complemented with FCEV – mostly for heavy trucking).

The notable divergence between the scenarios is in the decarbonization of the building sector, where gas use in the Eurogas scenario is continued through the introduction of biomethane and decarbonized hydrogen, but also continued use of (unabated) natural gas. This contributes to Eurogas being the cheaper net-zero pathway, as it foregoes the costs for an extensive renovation of both heating equipment and insulation in existing residential and commercial buildings. The following paragraphs describe how each sector reduces its emissions.

4.1 Electricity generation

Electricity generation is set to increase strongly in both scenarios (see figure 21). A trend fuelled by both increased electrification of end use as well as the cost-effective deployment of variable renewable energy sources (VRES), particularly wind power.[35]

In both scenarios, VRES increase strongly and contribute significantly to decarbonization. From 2020 until 2050, VRES (solar and wind energy) are estimated to grow at an annual growth rate of 7.4% under 1.5TECH and 5.7% in Eurogas. In the 1.5TECH scenario these growth rates are particularly driven by the increasing carbon price of 350 EUR/t that delivers an additional 38% (1.868 TWh/yr) of VRES versus the Eurogas scenario by 2050 with a carbon price of 100 EUR/t. This leads to VRES reaching 50% of total electricity supply by 2032 in 1.5TECH while in the Eurogas scenario this level is achieved 6 years later.

The Eurogas scenario sees a reduction of natural gas use for electricity generation of 3% compared to 2017, albeit increasingly complemented with CCS, which reaches full post-combustion deployment before 2050. Electricity generation in the Eurogas scenario sees biomass as a fuel increasing more than 1.5 times over the full period or 1.5% per year, creating significant net negative emissions. Coal fired and nuclear electricity generation are reduced in both scenarios, but more strongly in Eurogas with reductions of 97% (18 TWh in 2050) and 64% (298 TWh in 2050) for coal-fired and nuclear respectively. In the Eurogas scenario combusting power plants increase their carbon capture rate from 5% of emissions in 2028 to 95% in 2049.

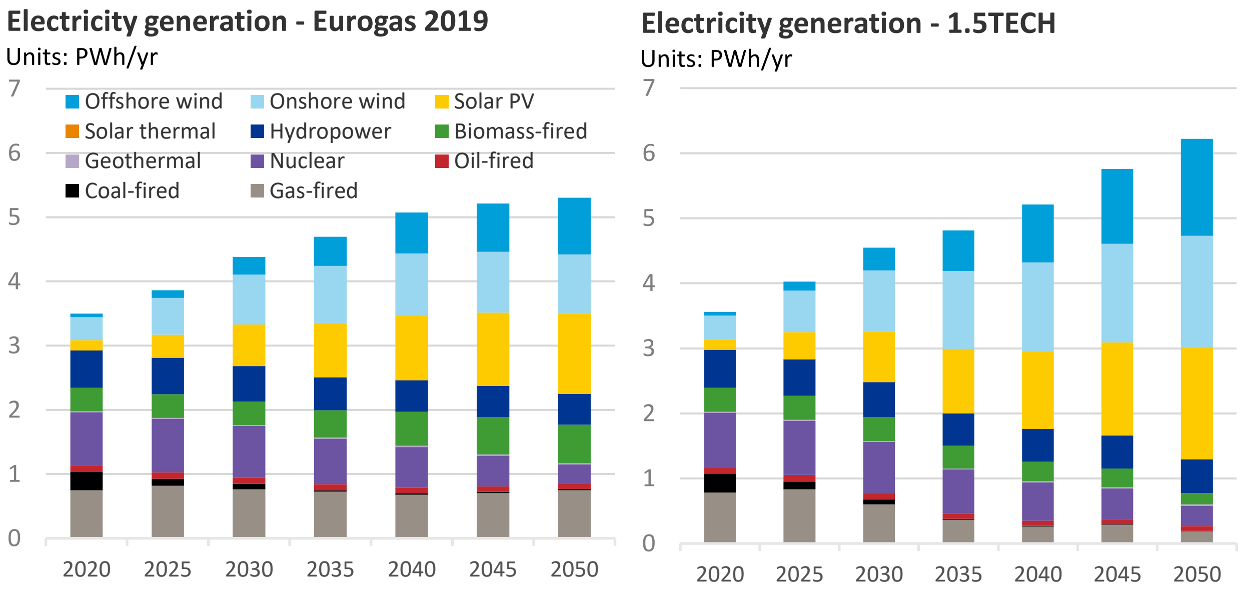


Figure 22 Electricity generation by station type for the Eurogas and 1.5TECH scenarios

4.2 Manufacturing

In both scenarios the decline in energy demand in the manufacturing sector is a consequence of the continued decline in Europe's share in global manufacturing output. From 2020 to 2050, production volumes in Europe are likely to decrease by 20%. In addition, declining energy efficiency trends still imply a 30% improvement in energy efficiency from 2020 to 2050. In contrast to the transport and buildings sector electrification in this sector does not come with "automatic" energy efficiency gains as

[34] "Other energy" include emissions from non-energy use, H_2 production, energy sector own use, and other.

[35] See Appendix B for cost development for various VRES technologies

not all electric alternatives are more efficient to fossil incumbent technologies, particularly in heating and for feedstock uses. Therefore energy efficiency improvements need to come through a host of other technology and process improvements.

Both scenarios see an annual decline in energy demand 1.3% in this sector. About a third of this is caused by a decline in overall manufacturing volumes[36], but most is caused by energy efficiency improvements. This leads to a reduction of manufacturing energy demand from 3.400 TWh/yr in 2020 to 2.200 TWh/yr in 2050 in both scenarios.

While natural gas plays an important role in supplying energy to the manufacturing sector today; its role is continuously reduced in both scenarios (Figure 22). In line with the underlying assumptions of the scenario and notwithstanding the effect of energy efficiency measures, 1.5TECH sees an absolute increase in electrification to 57% (1233 TWh/yr) of total demand - an 18% increase over the Eurogas scenario of 902 TWh/yr). Together with hydrogen, it satisfies the bulk of energy demand in the manufacturing sector in 2050.

In the Eurogas scenario, electricity demand from manufacturing is slightly reduced in absolute values (at 1200 TWh in 2017), but increases relatively to 41% of energy demand (up from 33%). Hydrogen supplies a similar amount of energy to the manufacturing sector as electricity (794 TWh/yr), signifying its continued use of gaseous energy. Overall, the lower infrastructure costs allocated to the sector lead to 12% lower energy costs for manufacturing under the Eurogas scenario.

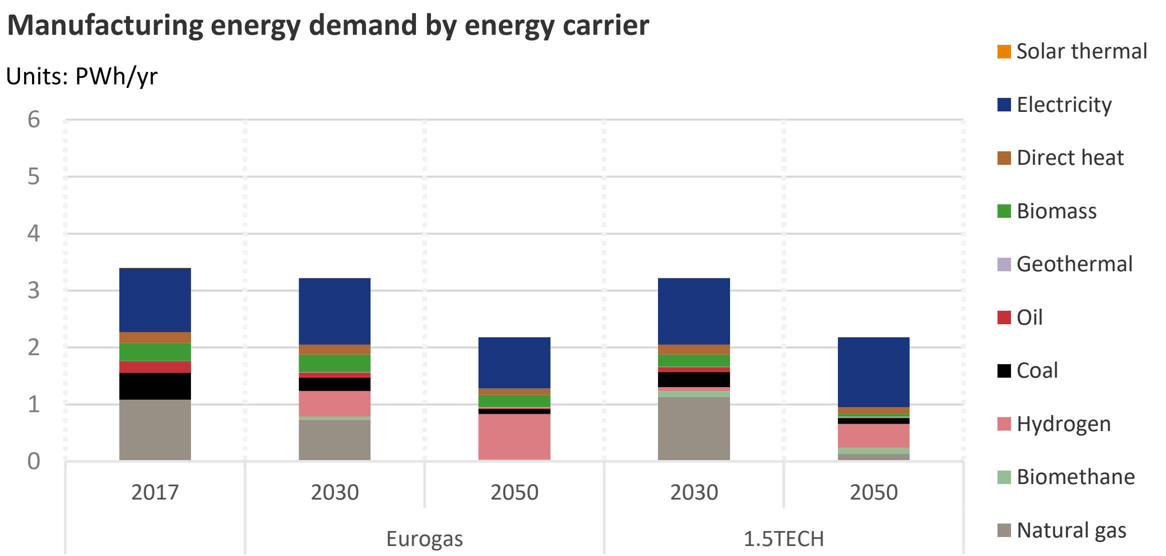


Figure 23 Final energy demand in the manufacturing sector by energy carrier

4.3 Buildings

The building sector is currently the leading energy consuming sector. Furthermore, towards 2050, the reduction in energy demand is smaller than in other sectors, partly because increasing affluence (and lifestyles) will increase demand for more and larger homes and offices. Still, both scenarios arrive nearly at zero emission intensity in 2050 through net negative emissions from other sectors[37]. Under the

[36] In addition to decline in from offshoring, increasing recycling also reduces need for output and contributes to declining energy demand. These developments are equal in both the Eurogas and 1.5TECH scenarios.

[37] Net negative emissions in power production through combustion of solid biomass and biomethane benefits buildings, as they experience increased electrification in both scenarios

Eurogas scenario energy demand from buildings is only 9% lower compared to 2017 while under 1.5TECH energy efficiency measures imbedded in electrification – such as heat pumps- achieve a reduction of 21% by 2050.

The average expected life time of heating equipment in buildings is 15 years, and allows –in the absence of any incentive schemes– for new technologies, including switching to other fuels, to be up taken only if they are more cost-effective at that time (including effect of initial investment into equipment and expected future fuel-subsidies). In addition we assume a building stock renovation rate of 2% per year that provide for an further increase of energy efficiency of the sector.

Note that the study uses an improvement in heat pump efficiency in the future. Though the fractional improvement is similar to that forecasted by manufacturers, the real efficiency is much lower than generally stated. First, heat pumps peak energy demand is high by low temperatures, when heat pump efficiency is low. Therefore, the power grid must be designed for such events which requires additional investments.[38] Secondly, heat pump efficiencies are reduced as user behaviour frequently offsets much of the expected efficiency improvements. This is caused by users trying to achieve better heating (and cooling) comfort levels. Both factors are detrimental to the real-life efficiency of heat-pumps.

The 1.5TECH electrification of the building sector comes at a cost and we find that significant subsidies to owners and users of commercial and residential buildings are required to have stated electrification rates — a total of 10 trillion Euro over the period to 2050 — are required to achieve the stated 1.5TECH buildings' electrification rates. These subsidies are the primary reason for the total costs being higher in the 1.5TECH scenario than compared to the Eurogas scenario.

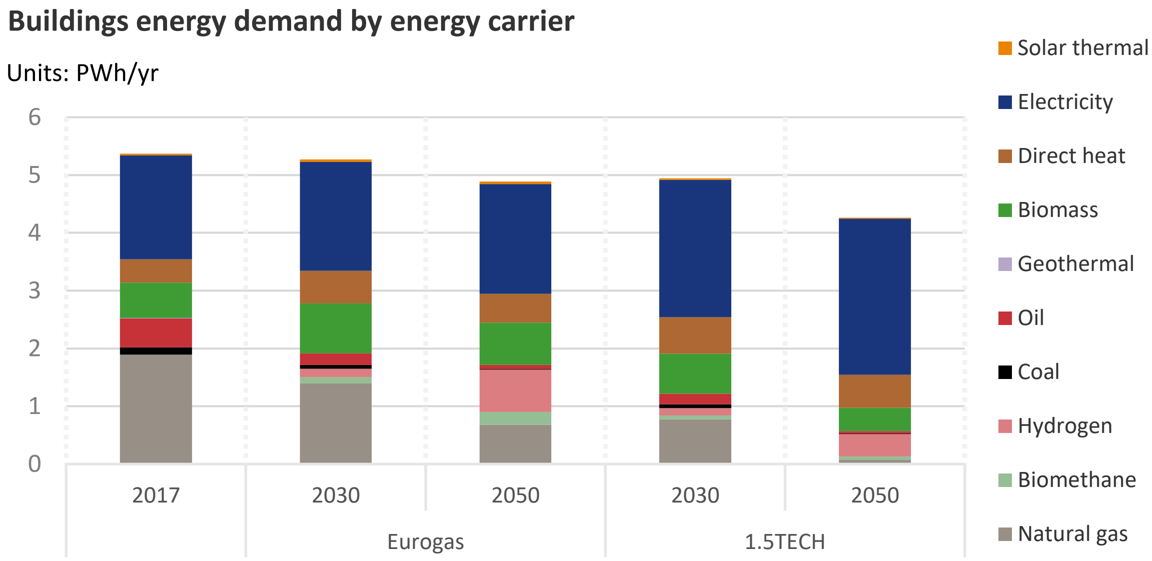


Figure 24 Energy demand in the building sector by energy carrier

4.4 Transport

Following the buildings sector, transport consumes most energy. But unlike the buildings sector, energy efficiency is expected to more than halve energy demand by 2050, or by approximately 2.5% per year. Energy efficiency is achieved by direct and indirect electrification of road transport, where battery

[38] See chapter 5.2

electric vehicles (BEVs) attain propulsion efficiencies of 90% and fuel cell electric vehicles (FCEVs) of 60%.

Both starkly contrast to vehicles propelled by internal combustion engines (ICEs) which attain average propulsion efficiencies of less than 30%. Overall, the road fleet in both scenarios see very similar developments with BEV dominating drive trains for both commercial and passenger vehicles by 2050 (Figure 25). The reduction in passenger fleet size by 2050 is due to vehicle automation and ride sharing These development reduce vehicle numbers, but as ride-sharing vehicles drive more, vehicle annual kilometres are expected to not be impacted by this shift. Commercial vehicles through use have limited "ride share" functionality and as such their numbers are not expected to decrease similarly.

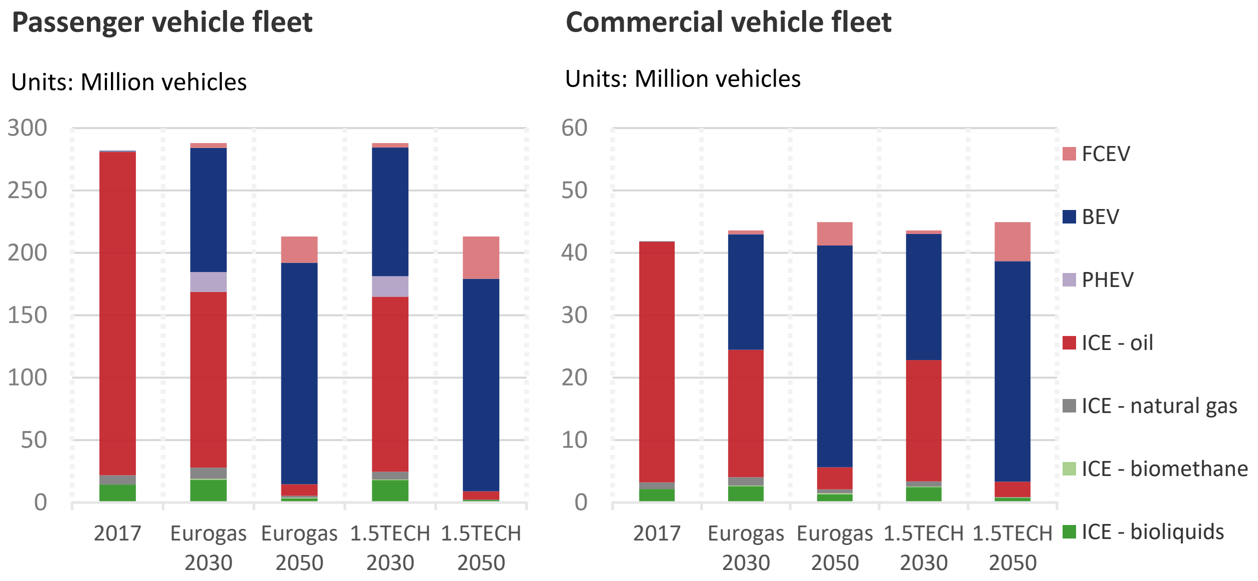


Figure 25 Road fleet composition for passenger and commercial vehicles

The relative shares of different energy carriers in final demand is quite similar across both scenarios in which 18% is supplied by gaseous fuels (Figure 26). Transport is a major driver for energy with consumption for Road Transport 60% (1298 TWh), Rail 2% (43 TWh), Aviation 28% (606 TWh), and Shipping 12% (260 (TWh) in the Eurogas scenario in 2050.[39]

In the Maritime and Aviation sectors electricity remains a marginal energy carrier in 2050. In both the Eurogas and 1.5TECH scenarios fuel demand in aviation demand is primarily served by increasing bioliquids 41% (253 TWh) and oil use 55% (340 TWh) in 2050. While in the Maritime sector the Eurogas scenario provides an inroad for indirect electrification through hydrogen/ammonia uptake reaching 31% (81 TWh) of total maritime demand. In the 1.5TECH scenario maritime transport is primarily fuelled by Bioliquids 57% (147 TWh) in 2050.

[39] For Aviation and Shipping extra EU travel is not accounted for in these figures, only intra-EU.

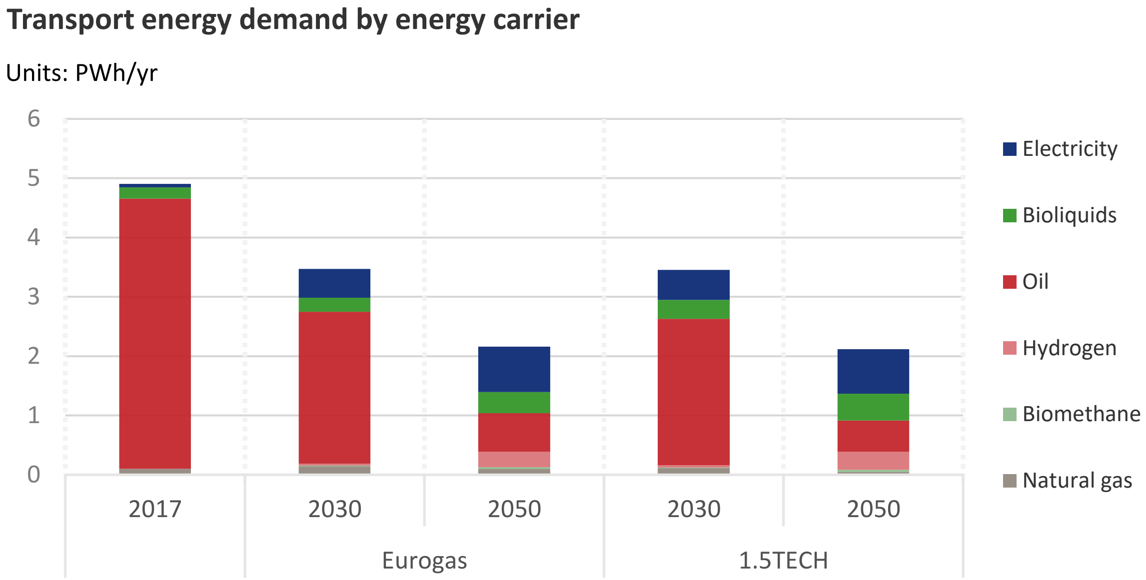


Figure 26 Transport energy demand by energy carrier

The latter two transport sectors are the main source of unabated emissions in both scenarios. Overall, the carbon intensity of the transport sector is slightly lower in 2050 in the Eurogas scenario compared to the 1.5TECH scenario. This is the result from a marginally higher share of direct and indirect electricity consumption and the negative emissions in electricity generation (tier two emissions) associated to this consumption.

Though identical in both scenarios, one should note that extra-European aviation and shipping are not reflected in Figure 25 (to adhere to current emission accounting conventions) LNG use in maritime transport reduces combustion emissions of about 20% compared to fuel oils. (Bio)LNG is however much cleaner when it comes to local pollution (small particles, NOx, SOx). Moreover, as the world's gas use will increase significantly over the next 20 years, and increasingly be shipped on keel, it is forecasted that ships that transport LNG will also use it for their own propulsion.

5 PROVIDING BENEFITS TO CONSUMERS

5.1 Affordability to European consumers

The Eurogas scenario results in less costs to the economy than 1.5TECH while achieving the same level of decarbonization. Figure 27 shows that cost savings in the Eurogas scenario approximates 0.5% of European GDP (cumulative 906 Trn Euro 2018-2050) or 600 euro per household per year over the 32-year period between 2018 and 2050.

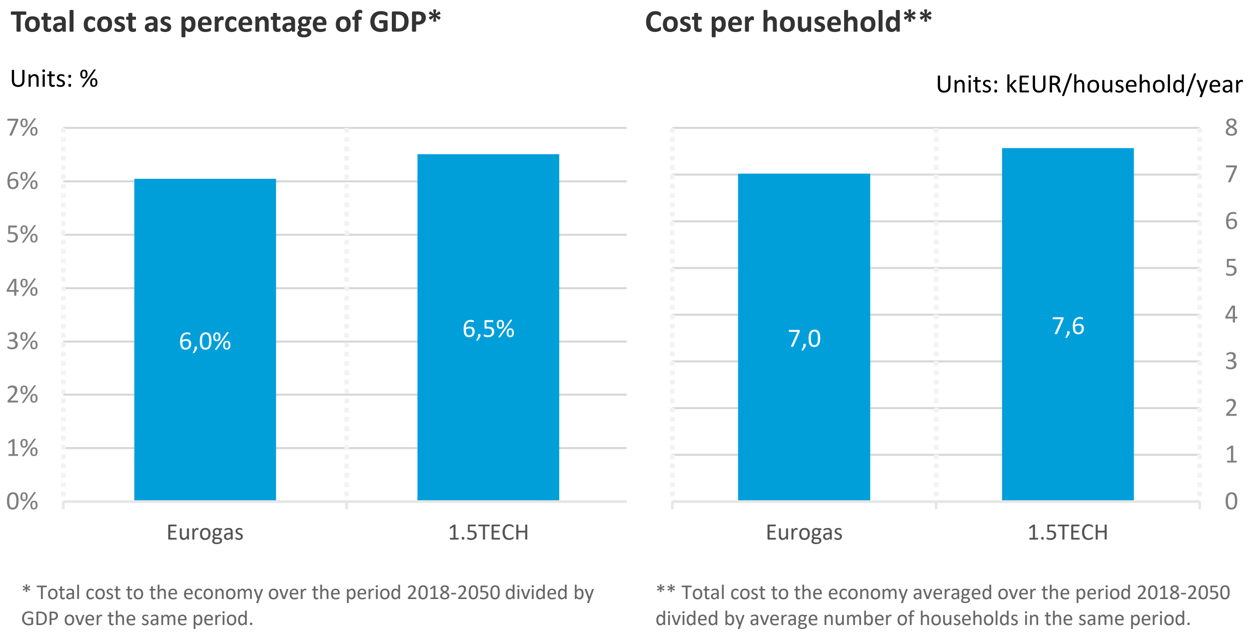


Figure 27 Total cost to the economy as percentage of GDP and cost per household by 2050

5.2 Cost of infrastructure

As outlined above, the cost of infrastructure is an important reason for the cost differences observed between both scenarios. Both scenarios see a continued need for expanding electricity grids. Historically, electricity grid investments stood at an average of 54 billion euro per year since 2000.

Under the Eurogas scenario, the average annual investment increases in the coming decade by roughly 20 billion euro per year and then reduces to an average of 63 billion euro in the period between 2030-2050. The 1.5TECH scenario requires increasing investments in electricity grids to assure sufficient capacity. Investments are approximately 100 billion euro per year in the period to 2050. Over the forecast period, CAPEX spent on electricity infrastructure is around 1.3 trillion euros lower in the Eurogas scenario compared to 1.5TECH. Figure 28 below summarizes these findings.

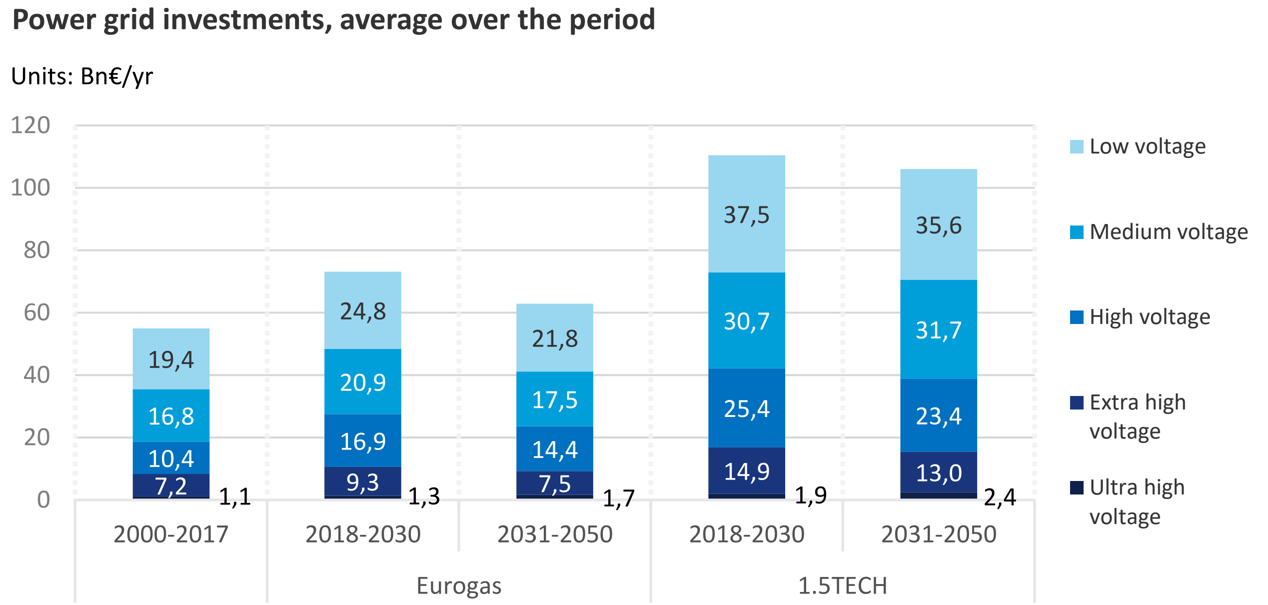


Figure 28 Required investments in electricity grids, averaged over the period shown

Electrification of demand, and especially for heating purposes, contributes to these higher investments. Even though electric heating is generally efficient when using heat pumps, their efficiency drops considerably when faced with lower temperatures when heat demand is peaking (see above). This leads to a situation in which the need for electricity grid capacity increases. Figure 29 below shows daily peak loads for 2017 and for 2050 under both scenarios and illustrates the effects electrification of (heating) demand causes.

In the Eurogas scenario the maximum daily peak load is lowered compared to 2017 mainly through increased demand response in the energy system. The 1.5TECH scenario sees the same benefits from demand response. But the much higher share of electricity heating at peak times counters this benefit, and requires more capacity in the power transmission and distribution system.

Mainly due to this effect, we foresee a need for nearly a doubling (1.85x) of peak demand from approximately 600 GW today to 1200 GW by 2050 in the 1.5TECH scenario. Another way to illustrate this is by the peak-to-average ratio: a value defined as the peak load divided by the average load in a year. In 2017, this value stood at 1.66 and grows to 1.85 under 1.5TECH. For Eurogas, it is reduced to 1.40 which thus results in lower investment needs for the electricity grid.

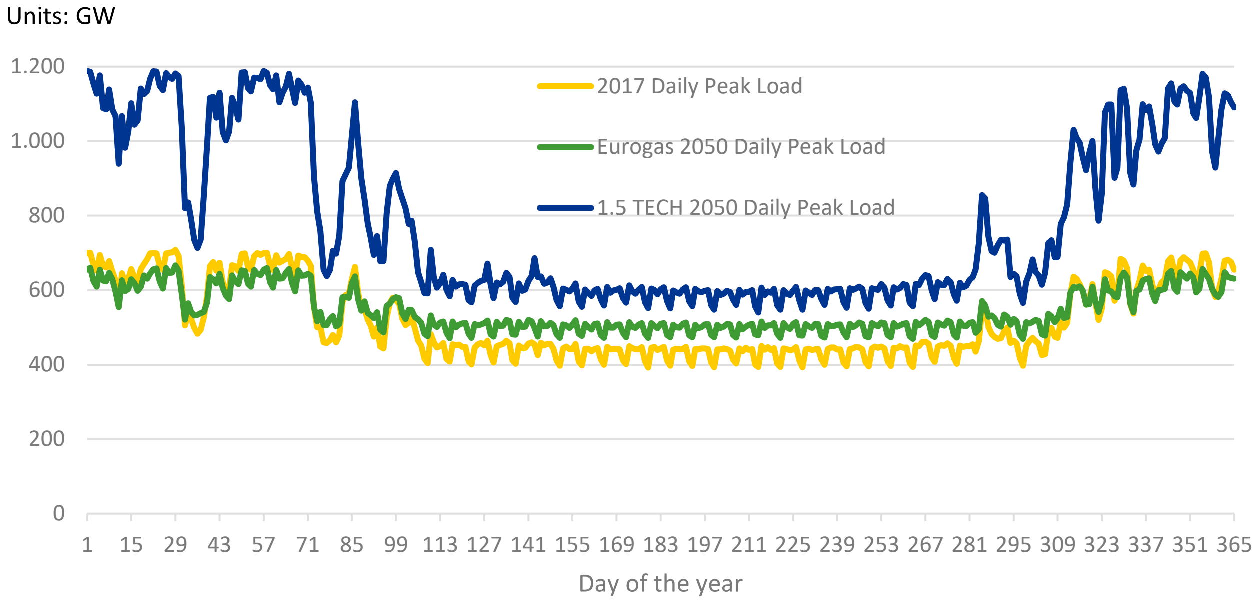


Figure 29 Daily peak loads of the electricity system

Re-enforcements of the electricity grid in the 1.5TECH scenario versus a (re)use of the gas network in the Eurogas scenario is a major driver of the cost difference between the two scenarios. Investments in gas infrastructure are shown below for both scenarios (Figure 30). Both scenarios see a large drop in gas infrastructure investments compared to recent history. A limited need for capacity expansion—and thus limited investments—in distribution systems result from plateauing final gaseous energy demand. Increasing CAPEX in the Eurogas scenario result almost exclusively from an increase in hydrogen uptake. For distribution systems, we assumed that repurposing these systems to hydrogen would cost 20% of new build costs, while cost of repurposing transmission systems are higher at 40% of new build costs due to the need for replacing compressor units.

In the period between 2030 to 2050, 92% of Capex in gas systems are required to accommodate hydrogen transport and use. The uptick in investments in distribution systems post 2030 is due to increasing hydrogen end use as hydrogen boilers reach cost parity and become more widely available. This removes an important barrier to dedicated hydrogen distribution networks development.

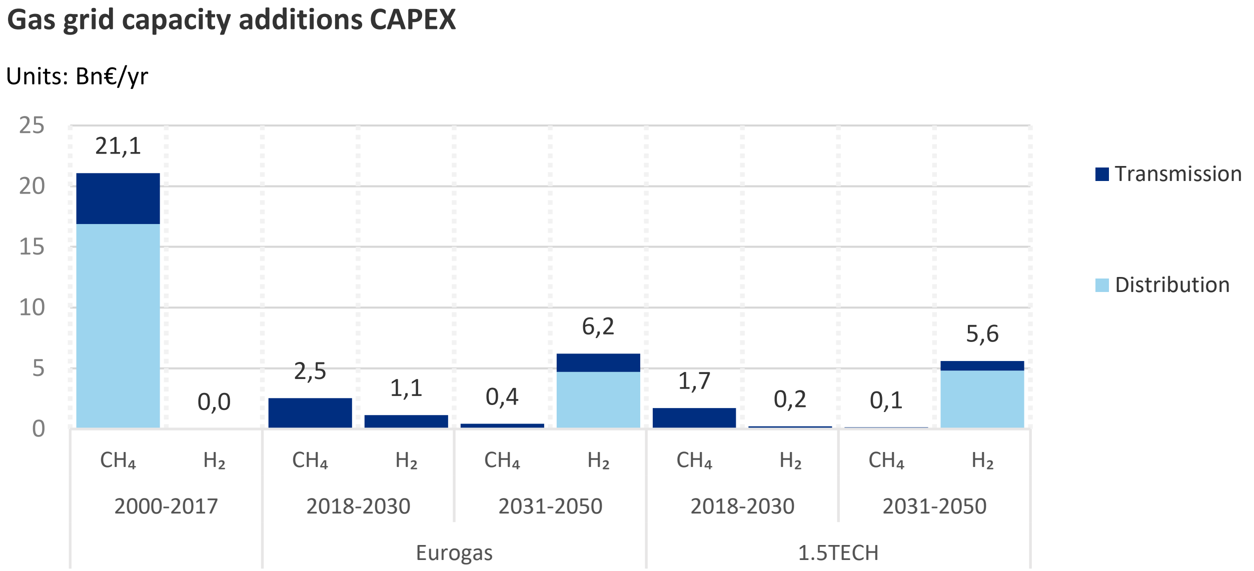


Figure 30 Investments for gas grid capacity additions for both (bio)methane (CH_4) and hydrogen (H_2)

5.3 Cost of energy supply and subsidies

The cost of energy supply is the cost to final consumers, including all production and supply, transmission, distribution and tax. Important parameters are energy prices, the electricity price and natural gas price developments are provided in Figure 31 below. These prices are wholesale prices. For the electricity price the model simulates hourly supply and demand taking into account a number of flexibility options, such as EV and dedicated grid batteries, peaking combustion power plants, using the grid, demand response and conversion into hydrogen through electrolysis. The primary driver for lower wholesale power prices in the 1.5TECH scenario, is the high VRES share in this scenario drives down prices, as they have zero marginal cost.

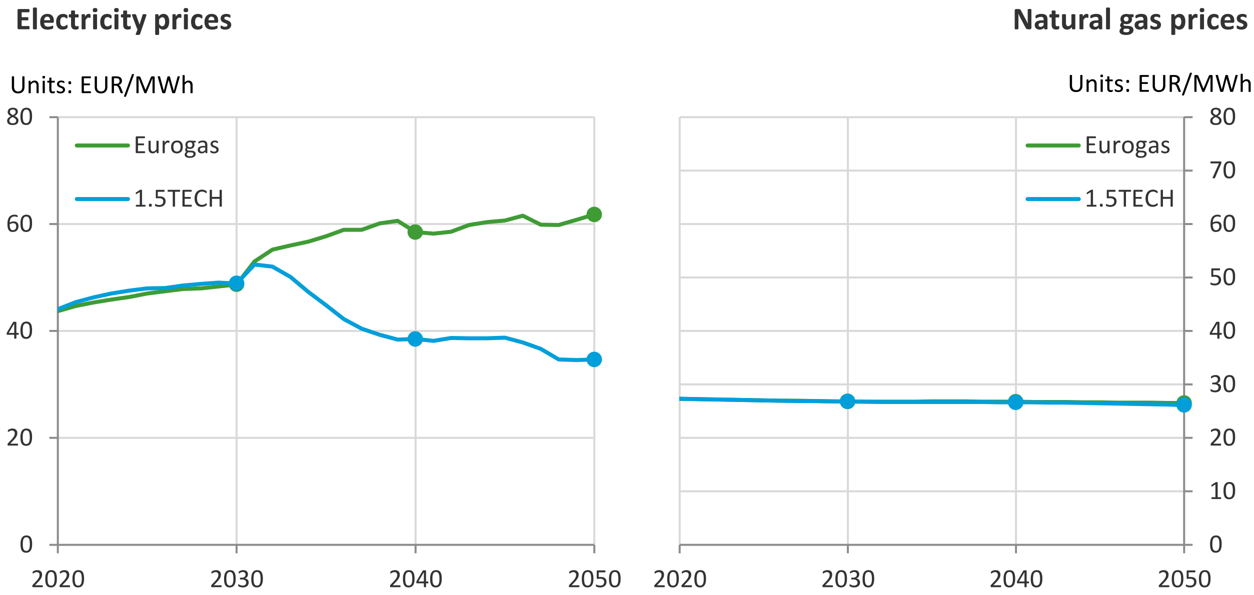


Figure 31 Wholesale electricity and natural gas prices in Eurogas and 1.5TECH

Energy costs for the manufacturing sector are nearly equal in both scenarios, standing at around 190 billion euro per year on average over the period 2030 to 2050. Energy cost in the transportation sector are – at ~500 billion euro per year – 7.7% higher under the Eurogas scenario than under the 1.5TECH scenario. Finally, we see a larger difference for the buildings sector. Under the Eurogas scenario, energy costs are over 40% higher than under 1.5TECH. However, combined with subsidies allocated to the buildings sector, total cost to this sector are 10% higher than those under Eurogas.

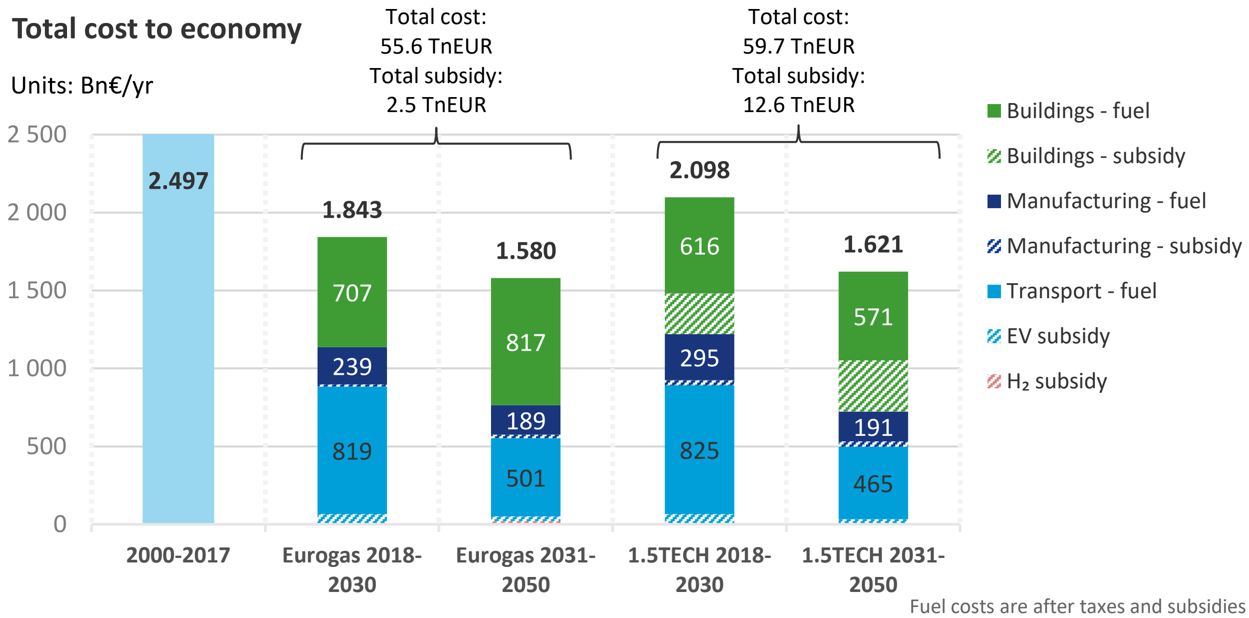


Figure 32 Cost to the economy by energy (fuel) costs and subsidies

In both scenarios subsidies are applied to four categories; the use of hydrogen, electric vehicle uptake, manufacturing decarbonization, and building decarbonization. For buildings and manufacturing, the subsidies modify the de facto energy bill paid by the final energy user, the exact form of subsidy may differ. Sometimes the subsidy provided is in supporting equipment purchase (such as EVs, boilers, or heat pumps), at other times the energy carrier in question is supported by the government footing part of the bill.

For 1.5TECH, subsidies are applied to achieve the mix of energy carriers in each sector. As mentioned, buildings electrification required much lower than market power prices, and so received massive subsidies to enable the stated electricity share in that sector. For electrolysis, subsidies have been applied to enable cost competitiveness to similarly ensure a share of green hydrogen as stated in 1.5TECH. EV subsidies are identical in all scenarios and based on ETO2019 EV policy forecast.

For the Eurogas scenario, discussions with the client, stakeholders groups, and DNV GL group expertise was used in order to achieve zero emission at a low cost. No subsidies were applied for the buildings sector in the Eurogas scenario, as the simple cost optimization rule was deemed to achieve sufficient emissions reduction. While hydrogen use, vehicle electrification, and manufacturing benefitted from some public support – in line with the assumptions in the 1.5TECH scenario.

6 CONCLUSIONS

This report investigated pathways to a decarbonized European energy system in 2050 and assed the role of gaseous energy supply in both pathways. We developed a scenario that builds on the advantages of energy delivery through existing gas networks. This 'Eurogas scenario' saw a continued, albeit changing role, for gaseous energy in a zero emissions future. We compare it to an alternative pathway focusing on replacing gaseous energy with electricity. Both scenarios reach equal emissions reduction levels of at least 100% but differ in the total cost for the European economy and society.

Scenarios

Whilst the 'Eurogas scenario' has been developed in conjunction with Eurogas, the other scenario—which we refer to as 1.5TECH—is DNV GL's interpretation of the European Commission's 1.5TECH scenario that was presented in 2018 as part of the *"long-term strategic vision for a prosperous, modern, competitive and climate neutral economy"*. We have remodelled the latter scenario using our Energy Transition Outlook Model (ETOM) to match, as closely as possible, the EC's 1.5TECH scenario given the data available to us and its outcomes.

The scenarios achieve 100% CO_2 reductions in two different ways:

1. The Eurogas scenario represents a choice for gaseous energy delivered by existing gas infrastructure. It sees an important role for the supply of renewable and decarbonized gases, which transform European energy supply through a mix of natural gas, biomethane and hydrogen, complemented with carbon capture and storage (CCS) technology.

   The shares of electricity and gaseous energy both increase. Even though electricity increases its share in final energy faster than gaseous energy, both are comparably in 2050 (36% and 32% respectively). Emissions are gradually reduced to 55% of 1990-levels by 2030 and are reduced by 100% in 2050.

2. The 1.5TECH scenario supports decarbonization of the energy system through increasing renewable electricity uptake. The role of natural gas is a supportive and diminishing one. This scenario limits biomethane and hydrogen supplies to hard-to-decarbonise sectors.

   Electricity's share in final energy demand sharply rises to more than 50% in 2050 (up from 20% in 2020). Gaseous energy supply is reduced from 24% today to 20% in 2050. Emissions under 1.5TECH are reduced to 63% of 1990-levels by 2030 and by 100% in 2050 as well. As such, 1.5TECH's emissions reduction pathway is steeper towards 2030.

Decarbonizing gaseous energy supply

In the Eurogas scenario the use of gaseous energy carriers is an important pillar to achieve net zero emissions. We included four sub-types of gaseous energy of which the first three can be used to decarbonise gas demand:

1. Biomethane
2. Hydrogen
3. Natural gas decarbonized through use of CCS technology
4. Natural gas

Biomethane is produced from second-generation feedstock and indistinguishable from natural gas once injected into the gas grids. Hydrogen can be used purely in separate grids or blended with methane in the existing gas grids used to supply consumers. CCS technology can be used at the point of natural gas consumption in order to remove the carbon it emits into the atmosphere. CCS can also be used to decarbonize gas at the point of production (so called pre-combustion), creating what is called ‘blue hydrogen’. Green hydrogen can be produced through electrolysis of water using renewable energy.

The cost of supplying decarbonized gases reduces over time due to so-called learning effects: the more capacity of a certain technology is installed, the lower its cost will be. Due to these effects particularly cost of electrolysis (for green hydrogen) is expected to drop sharply after 2030. Its limited installed base today allows for large cost reductions once scaling occurs. Scaling of green hydrogen is achieved through the allocation of subsidies. CCS is also expected to reduce strongly in costs as use is propelled by increasing carbon prices in both scenarios. Whilst biomethane costs fall towards 2030, they increase again towards 2050 due to increasing feedstock prices.

The 1.5TECH scenario sees a reduction of 29% (1532TWh) in gaseous energy supply, but grows by 18% (936 TWh) in the Eurogas scenario towards 2050. Supply of biomethane reaches 113 bcm per year (or 16%/1,014 TWh of gas in energy terms), while hydrogen provides 29% (1,783 TWh). Together they achieve a 45% share of gaseous energy supply with the remaining 55% supplied by natural gas mostly decarbonised through CCS technology.

Achieving these high shares of hydrogen, biomethane and the level of decarbonization depends on a rapid and sustained scaling up of biomass gasification capacity and (decarbonized) hydrogen production by 5% per year until 2050. Similarly, decarbonizing the remaining natural gas supply requires scale-up and significant deployment of CCS capacity.

Even though the supply of energy through the gas network remains high in the Eurogas scenario its carbon intensity reduces significantly through blue and green hydrogen, biomethane, and post-combustion CCS) and reaches a decarbonization level of close to 90% in 2050.

Sectoral energy demand

In both scenarios all energy demand sectors must decarbonise extensively in order to achieve the EU’s net zero emissions targets in 2050. Electricity generation and manufacturing must become carbon negative to achieve the target in both scenarios. Under the Eurogas scenario, the use of decarbonised gas and biomass decarbonized through the use of CCS technology in these sectors compensate for the remaining emissions produced by the increasingly less carbon-intensive buildings and transport sectors. The same occurs under 1.5TECH scenario, although to a lesser extent, as this scenario reduces emissions almost evenly across all sectors.

There are several noteworthy similarities between both scenarios:

- Decarbonisation of the electricity and manufacturing sectors depends on CCS technology and infrastructure being scaled. Electricity generation strongly increases under both scenarios because of increased electrification and cost reductions achieved in renewable generation technologies, particularly wind power. Manufacturing primarily reduces energy demand through energy efficiency measures.
- Biomass use and second-generation biomethane technologies are pillars of Europe’s decarbonisation efforts. They are crucial for net negative emissions
- The transport sector, the second highest energy consuming sector after the buildings sector, follows similar pathways of electrification of road transport led by battery electric vehicles (BEVs). Fuel cell electric vehicles (FCEVs) complement BEVs in commercial road transport.

In both scenarios, energy demand from the buildings sector does not reduce to the same extent as in other sectors in 2050. However, the energy carrier supplying this sector varies between the two scenarios. In the Eurogas scenario, natural gas and the scaled use of biomethane and hydrogen continues to deliver a substantial share of the sectors energy use. While in the 1.5TECH scenario a strong increase in the use of electricity for heating is achieved.

Economic impact on Europeans

The total cost of the Eurogas scenario in the lead-up to mid-century is 4.1 trillion euro (7%) lower than under the 1.5TECH scenario. This difference approximates 0.5% of European GDP (cumulative 906 trillion euro 2018-2050). This is equivalent to saving 130 billion euro per year or 600 euro per household per year over the 32-year period between 2018 and 2050. There are two primary reasons for the lower costs under the Eurogas scenario:

1. Subsidies to incentivise/support consumers to opt for decarbonised energy solutions are 80% (10.1 trillion euro) lower than in the 1.5TECH scenario. Over the forecasted period the 1.5TECH scenario requires subsidies of 300 billion euro per year to electrify heating in the buildings sector.

2. The Eurogas scenario saves cost by repurposing existing gas infrastructure instead of building new electricity infrastructure. Even though considerable investments in the power grid are required under the Eurogas scenario, these are 34% (or 1.3 trillion euro) lower that the investments required to reinforce and expand the power grid in the 1.5TECH scenario. Gas and electricity network investments combined are 35% lower in the Eurogas scenario than in the 1.5TECH scenario.

Electrification of energy demand under the 1.5TECH scenario — especially for heating purposes — therefore contributes to these higher investments. Although electric heating using heat pumps is efficient, efficiency drops considerably when faced with lower temperatures when demand for heat rises in Europe. This requires an increase in electric grid capacity throughout the year. Indeed, under the 1.5TECH scenario peak demand for electricity rises from just over 600 GW today to 1200 GW by 2050. Under the Eurogas scenario there is no expected increase in grid capacity peak demand. The effects of potential demand side responses are included in both scenarios.

Both scenarios predict a large drop in gas grid investments compared to recent history. Increasing gas grid investments in the Eurogas scenario result almost exclusively from an increase in hydrogen uptake. Between 2030 and 2050, 92% of investments in grids are required to accommodate hydrogen use.

Pathways to a decarbonized European energy system

We compared the findings from the Eurogas scenario with two notable studies published on decarbonization of the European energy sector: The Eurelectric (2018) and Gas for Climate (2019) pathways. Both achieve a 95-100% decarbonized European energy system in 2050. Although there are considerable differences in the objectives, scope and modelling mechanics underpinning each scenario, some important lessons for deep decarbonization pathways can be learned, namely:

- All scenarios depend on extensive up-scaling of renewable power generation (non-fossil excluding nuclear) with installed capacity at over 80% of total installed capacity in all scenarios in 2050.

- Gaseous energy use and supply continues beyond 2050 in all scenarios with considerable differences observed in the level of use in the manufacturing and building sectors

- The Eurogas scenario is considerably more positive on CCS uptake than the Eurelectric and Gas for Climate scenarios. However, with decarbonization ambitions tightening towards 2050, this indicates that CCS, and carbon use (CCUS), technologies must support emission reductions in hard-to-decarbonise sectors of energy demand

- In all scenarios, the cost of fully-decarbonized energy supply will increase as economic and policy measures need to be considerably more incentivizing than they currently are. The Eurogas scenario forecasts reduced cost through continued use of the gas network (130 billion euros per year) compared with the Gas For Climate scenario (217 billion euros per year). The Eurelectric scenario does not provide a cost figure for the buildings and manufacturing sectors.

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APPENDIX A
Modelling of the energy future

This appendix discusses:

1. Our Energy Transition Outlook Model (ETOM)
2. The main input assumptions for the Eurogas and 1.5TECH scenarios
3. A comparison between the results of our interpretation of 1.5TECH and the original 1.5TECH
4. The relationship between decarbonization of the energy system (which is modelled in ETOM) and the economy as a whole.

DNV GL's Energy Transition Outlook Model

The Energy Transition Outlook Model (ETOM) is based on behavioural economics to mimic how real decision makers make decisions. Decision makers are usually not entirely rational optimizers, but are prone to biases, errors and so on to cope with a complex reality. The model is a non-linear feedback model implemented in the System Dynamics transition. This is means that relationships included are not just linear ones, but reflect a mostly non-linear real world energy system with mostly endogenous investors and partly endogenous policy making. It is a global model, with Europe being one of ten global regions. The regions interact and trade both energy and manufactured goods. Designed for long term energy forecasting, it contains more than 100,000 equations.

Figure 33 below presents the model framework. The arrows (large, dark blue from left to right) in the diagram show information flows, starting with population and GDP per person. Physical flows are in the opposite direction (not shown). Policy (at the top) influences all aspects of the energy system. Energy efficiency improvements in extraction, conversion and end-use are a cornerstone of the transition.

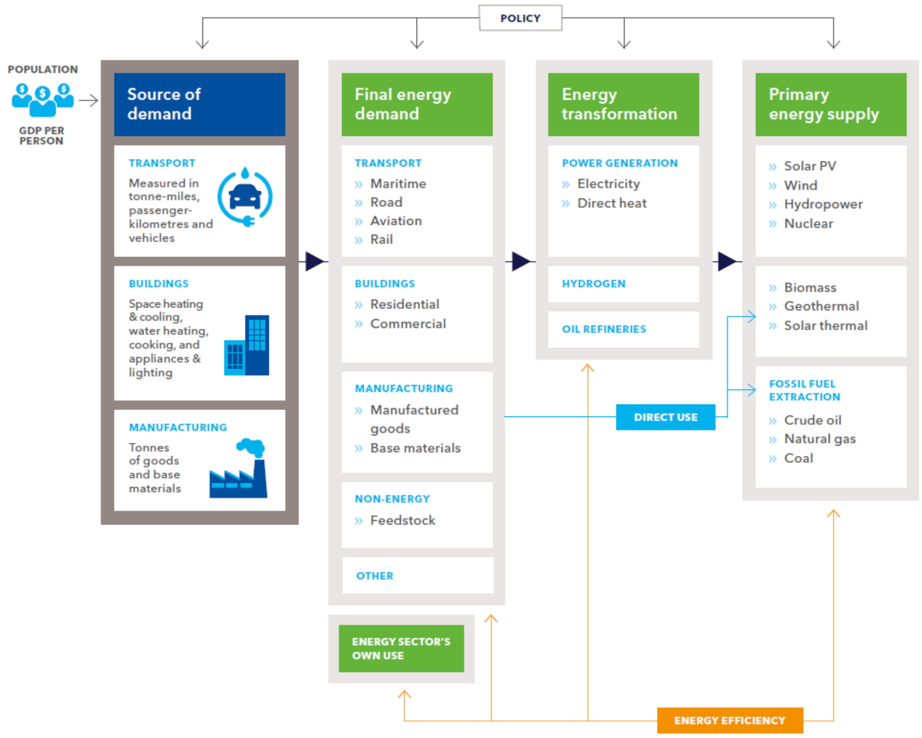

Figure 33 Energy Transition Outlook Model (ETOM) framework

A subset of the feedback loops in our model is shown below for the road transport and power sectors. Two of the cross-sector feedbacks are highlighted. Note that Figure 31 is a simplified illustration. There are similar feedback processes in other parts of our model. These self-reinforcing (positive feedback loops) and self-regulating (negative feedback loops) mechanisms automatically reflect path dependencies.

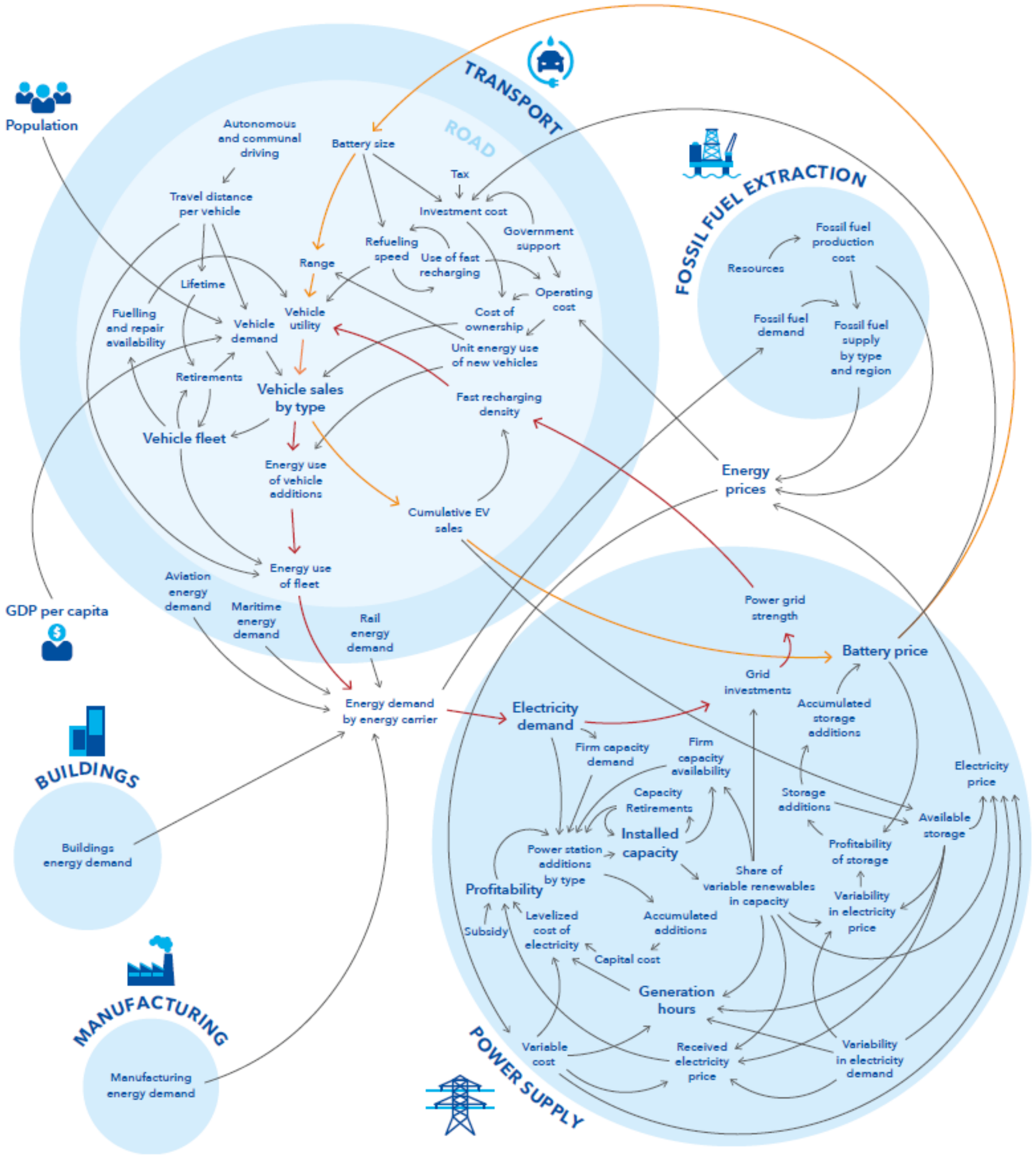

Figure 34 Overview of inputs & outputs in the ETO model

While ETOM's power sector contains hourly demand and supply for electricity, including a dozen supply flexibility options. Fossil fuel prices are based on long run extraction costs. A special focus is made to reflect issues related to the energy transition; notably endogenous vehicle electrification and a host of (exogenously determined) technology cost learning curves. As a System Dynamics model, all major energy consuming and supplying assets are reflected in a so-called stock and flow structure. This enables a good reflection of capital age, typically consisting in 'New', Recent' and 'Old' capital assets.[40]

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[40] DNV GL (2019). ETOM Documentation. DNV GL, Høvik

Modelling two comparable decarbonized energy futures

The table below outlines the key differences and similarities between scenario inputs.

Table 3 - Main input assumptions for each scenario

			DVN GL ETO 2019	Eurogas 2019	EU 1.5 TECH (DNV GL style)
General					
Geography			EU28 + NO, CH,..		
Sectors covered			All, excl. share of international shipping and aviation		
Emissions covered			CO2 from energy use & process emissions		
Carbon Price		**2030**	**EUR 29**	**EUR 58**	**EUR 73**
		2050	**EUR 50**	**EUR 100**	**EUR 350**
Transport					
Passenger	**BEV**	2030	19%	35%	36%
		2050	**89%**	**84%**	**80%**
	FCEV	2030	0%	1%	1%
		2050	**0%**	**10%**	**16%**
Commercial	**BEV**	2030	19%	43%	46%
		2050	**54%**	**80%**	**79%**
	FCEV	2030	0%	1%	1%
		2050	**16%**	**8%**	**14%**
Sectors					
Manufacturing's heat			Electrification supported	Decarb gas & elec. supported	Electrification supported
Buildings		2030	Electrification accelerates	Electrification moderates	Electrification accelerates
		2050	Gas reduced to 67% peak levels	Gas stays at 77% of peak	Gas reduced to 24% of peak
Power			VRES supported	VRES supported	VRES supported
Biomethane			Not available	Carbon price incentivised	Carbon price incentivised
Learning Rates					
PV	Panels		18%	18%	18%
	Other investments		8%	8%	8%
	O&M		9%	9%	9%
Wind	Turbines		16%	16%	16%
	Other investments		1%	1%	1%
	O&M		8%	8%	8%
CCS*	CAPEX		13%	13%	13%
	OPEX		15%	15%	15%
SMR**	CAPEX		0%	0%	0%
	OPEX		0%	0%	0%
Electrolysis	CAPEX		0%	18%	18%
	OPEX		0%	7%	7%

Assumptions regarding economic growth, energy prices, technology development (efficiencies, installed capacity in base year, starting cost of the technology, and learning rates) are similar. \

Comparability DNV GL's 1.5TECH and EC's 1.5TECH

DNV GL modelled a scenario that is similar—on outcomes—to the 1.5TECH scenario developed by the European Commission. 1.5TECH was selected because:

- It delivers an energy future that is compatible with the Paris climate treaty ambitions (1.5 degrees target).
- It achieves deep (100%) economy wide decarbonization.
- It depends on verifiable and quantifiable technology options, rather than assumed consumer behaviour.

We based our modelling of 1.5TECH on publicly available information. Some information required by us was lacking, especially the underlying assumptions used in the PRIMES model. Furthermore, methodological differences make a direct comparison between the PRIMES and our approach impossible. Still, by mimicking the outcomes of the EC's 1.5TECH, we can calculate the total costs for a 1.5TECH-like scenario.

Unfortunately, we were unable to precisely attain the same outcomes. This was mainly due to several underlying parameters we needed to maintain similar to our ETO-assumptions. This mainly concerned technological and economic parameters, the most important one being the technology learning rates and energy prices. The table below provides a comparison between the outcomes of 1.5TECH modelled in PRIMES and our interpretation.

Table 4 - Comparison of 1.5TECH as modelled by DNV GL versus PRIMES

	2030		2050	
	1.5 TECH PRIMES	1.5TECH DNV GL	1.5 TECH PRIMES	1.5TECH DNV GL
Buildings				
Electricity % in Residential Buildings	39%	43%	64%	59%
Electricity % in Commercial Buildings	63%	56%	80%	70%
Manufacturing				
Electricity % in industrial heat	Not available	5%	33%	32%
Electricity % in iron ore reduction		0.0%		0.0%
Biomethane % in industrial heat		5% + 11% biomass	31%	8% + 4% biomass
Natural gas % in industrial heat		60%	3%	11%
Hydrogen % industrial heat		4%	31%	34%
Transport				
Electricity in pass. road fleet	9%	36%	80%	80%
FCEV in pass. road fleet	4%	1%	17%	16%
Electricity in comm. Road fleet	6%	46%	79%	79%
FCEV in comm road fleet	1%	1%	15%	14%
Fuel mix in Aviation	Oil 100%	Oil 97% / Bio-liquids 3% / Electricity 0%	Oil 40% / Bio-liquids 20% / 40% E-liquids	Oil 55% / Bio-liquids 41% / Electricity 3%
Fuel mix in Shipping	Oil 92% / Natural gas 8% / Other 1%	Fossil 73% / Bio-liquids 25% / H_2 1% / Other 1%	Fossil 8% / Bio-liquids 51% / H_2 2% / Other 39%	Fossil 24% / Bio-liquids 70% / H_2 2% / Other 4%
Power				
VRES in Power	28%	45%	78%	79%
Hydro in Power	24%	12%	9%	8%
Nuclear in Power	16%	17%	4%	5%
Biomass in Power	0%	8%	4%	3%
Gas in Power	24%	13%	6%	3%
Carbon & Policies				
CO_2 reduction vs 1990	-46%	-55%	-100%	-100%
CO_2 price	28 €/tCO_2	73 €/tCO_2	350 €/tCO_2	350 €/tCO_2
Subsidies 2018-2050				Buildings 10Tn€, Manufacturing 1.1Tn€, Transport 1.5Tn€

Decarbonization of energy sector versus economy

The EU Green Deal aims for an economy-wide greenhouse gas reduction of 50-55% in 2030 where it originally was set at 40% in 2030. To this end, a comprehensive plan is expected in 2020 to "increase climate target to a least 50% and towards 55% in a responsible way". The Eurogas scenario achieves 55% reduction in CO_2-emissions in 2030.

Our ETO model simulates all energy-sector related CO_2-emissions and industrial process CO_2-emissions. Other greenhouse gas emissions are not modelled. We see that historical greenhouse gas emissions in the EU strongly correlate with energy sector CO_2-emissions (see Figure 35). The Eurogas scenario is thus an ambitious contribution of the energy sector to the Green Deal objectives. However, there remains a clear urgency for the energy industry to continue to reduce methane emissions from production, transport and use.

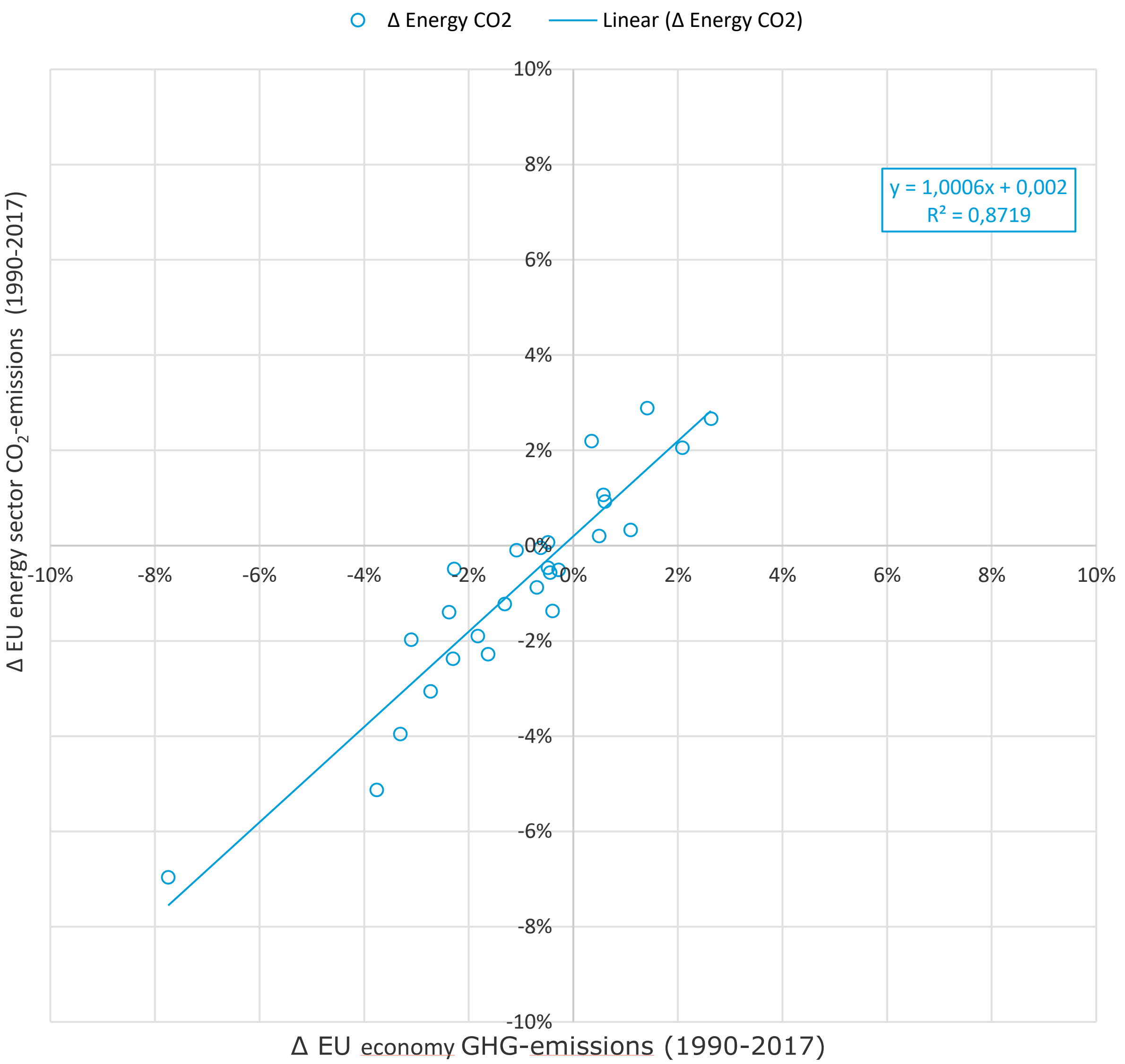

Figure 35 Correlation EU energy sector CO2-reduction and EU economy GHG emissions reduction

Methane emissions and decarbonization

This report looks at only CO2 emissions from the energy sector. Thus, CO2 emissions from combustion during oil and gas extraction (including flaring, if any) in Europe are covered, but related combustion emissions for oil and gas extraction from other regions are accounted for where emissions take place. Oil production related CO2 emissions are small and vary little between scenarios.

CH4 (methane) emissions are not accounted for. By 2050, the two scenarios' natural gas use differ by a factor 74%, and so differential CH4 emissions should also be a part of the zero emission calculations.

CH4 emissions, frequently called leakage, happen during the entire gas supply chain, but we have assumed that once in a pipeline, such emissions are negligible in Europe. Both safety and environmental measures already point in that direction, and by 2050, such emissions will practically vanish.

With respect to production, European CH4 emissions will continue to be lower than other regions in the world, at levels around 0.5% of produced volumes already seen today. By contrast, we assume that LNG shipped to Europe will mainly come from North America, with twice as high emission levels in 2050 during extraction. We expect significant legislation to limit CH4 emissions there, with the current administration laxing of methane emissions to subside either already 2021 – or after 2025. At the other end of the spectrum, Russian methane emissions will reduce, but continue to be the highest in the world at 3% of gas output. Middle Eastern and North-African gas emission levels are expected to continue to be in the middle with about 1.5% of produced volumes.

The tables below contrast the two scenarios. In 2050 Eurogas has 72% higher natural gas demand and also 74% higher CH4 emissions than the 1.5TECH scenario. This corresponds to 53 million tons CO2 equivalent - using GWP of 25, or about current (2017) CO2 emissions from fossil fuel combustion in Sweden.

Table 5 - Estimated methane emissions in Eurogas and 1.5TECH scenarios

1.5TECH	**North Africa**	**Europe**	**North East Eurasia**	**Middle East**	**Imports by sea**	**Total**
Natural gas use 2050 [bcm]	37	90	87	4	69	**287**
CH_4 emissions [bcm]	0.6	0.5	2.6	0.1	0.7	**4.4**
CH_4 emissions [mill. tons]	0.4	0.3	1.7	0.0	0.5	**2.9**
CO_2 equivalent [mill. tons]	9.1	8.0	42.9	1.0	11.3	**72.3**

Eurogas	**North Africa**	**Europe**	**North East Eurasia**	**Middle East**	**Imports by sea**	**Total**
Natural gas use 2050 [bcm]	65	150	152	7	119	**493**
CH_4 emissions [bcm]	1.0	0.8	4.6	0.1	1.2	**7.6**
CH_4 emissions [mill. tons]	0.6	0.5	3.0	0.1	0.8	**5.0**
CO_2 equivalent [mill. tons]	16.0	13.3	74.9	1.7	19.5	**125.5**

APPENDIX B
Technology and competitiveness

The following charts present the development of technology costs under the different scenarios. We note that the development of technology costs is dependent on the learning rate assigned to these technologies. Learning rates are similar for Eurogas and 1.5TECH. However, through the learning rate, the cost of a technology is dependent on its cumulative installed capacity. Differences in installed capacity between Eurogas and 1.5TECH result from differences in assumptions—such as carbon prices—and lead to different costs. All scenarios thus started with equal technology costs.

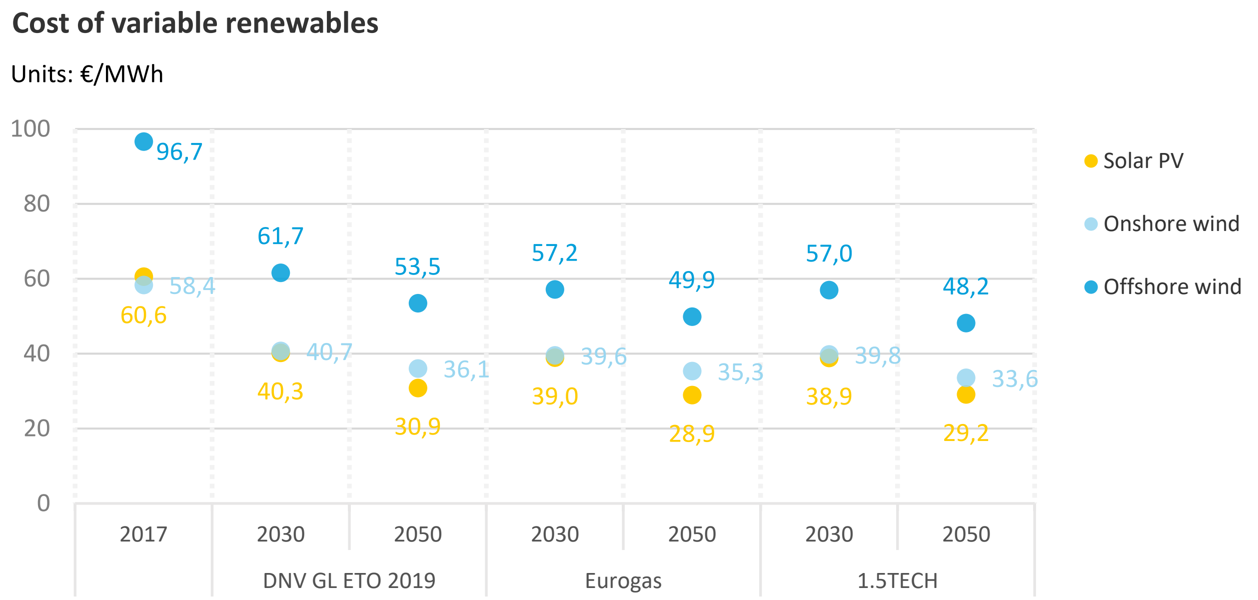

Figure 36 Cost development of variable renewable electricity sources

APPENDIX C
Price developments

The charts below present the energy and carbon price developments. Carbon prices are input to the model. Electricity prices result from the generation mix. Natural gas prices are based on consumed volumes and long-run marginal costs of natural gas.

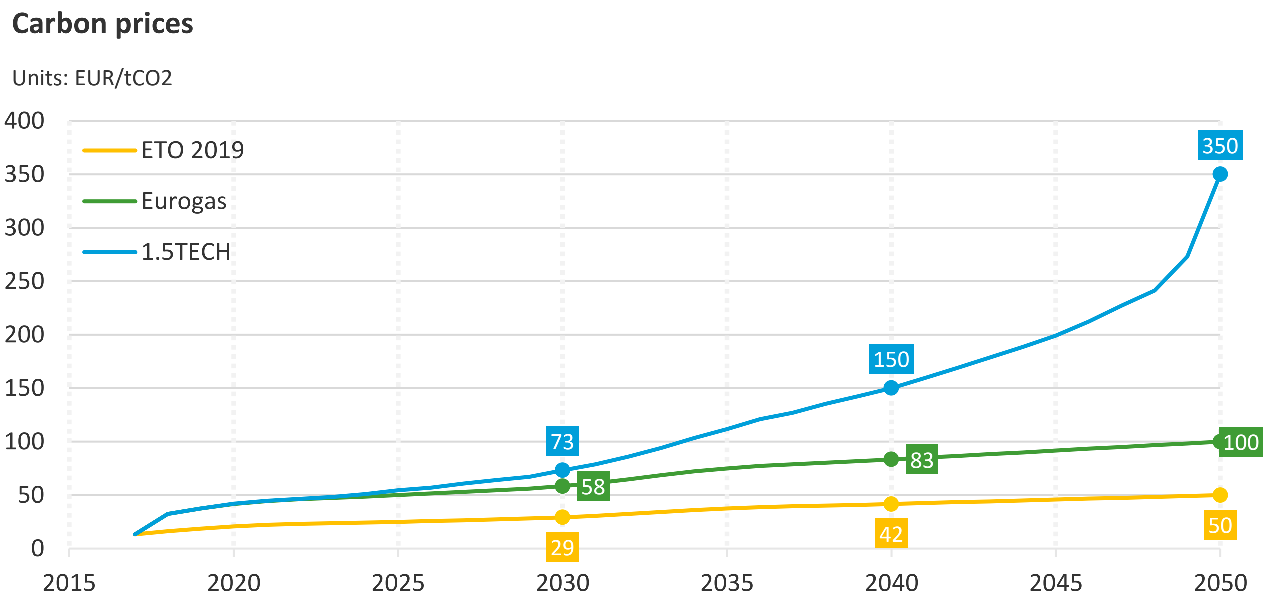

Figure 37 Carbon price development

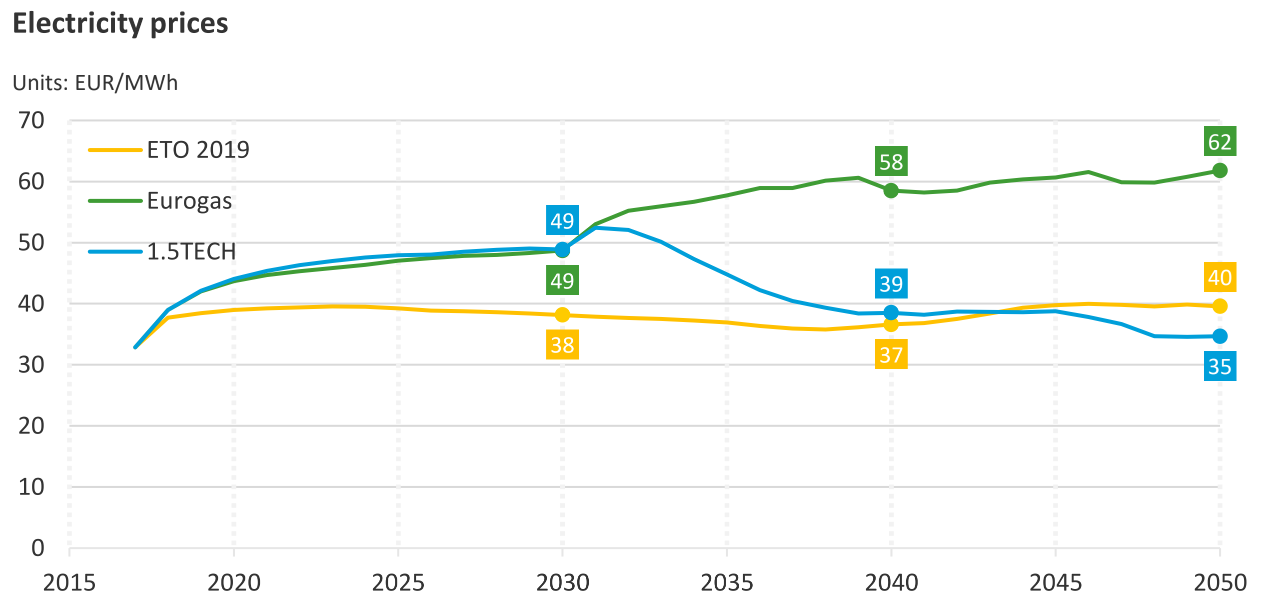

Figure 38 Electricity price development

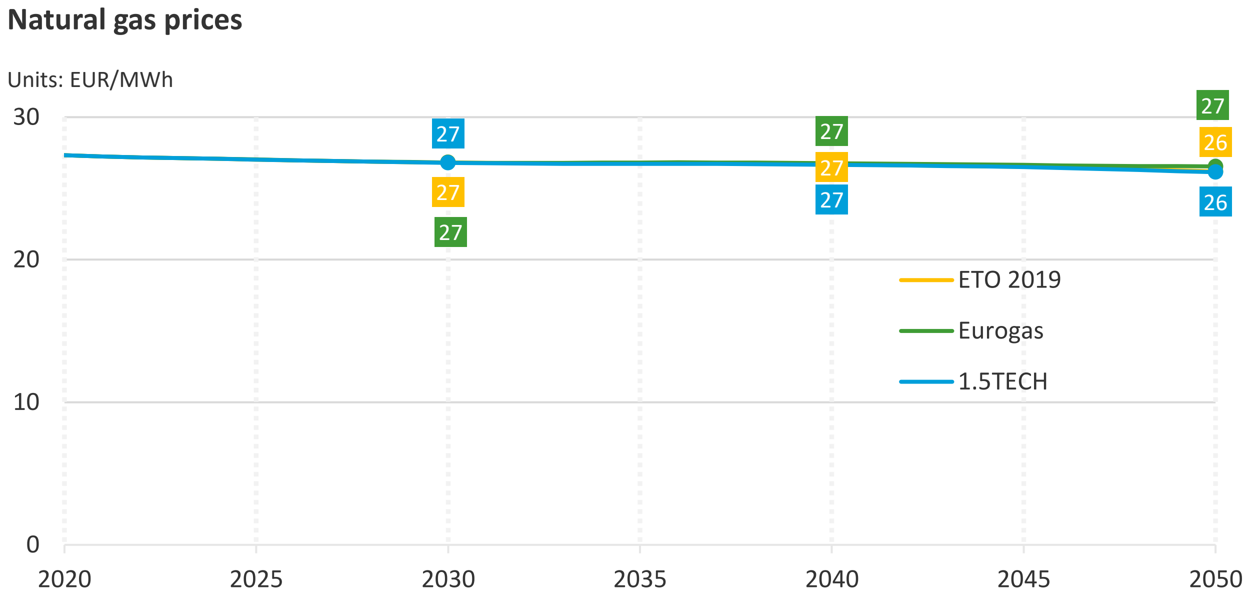

Figure 39 Natural gas price development

Carbon reduction, pricing and costs to economy

To asses robustness of the outcomes regarding the overall cost to the economy DNV GL remodelled the outcomes for the Eurogas and 1.5TECH scenarios with different carbon prices. Effectively swapping the carbon price level development toward 2050 between the two scenarios.

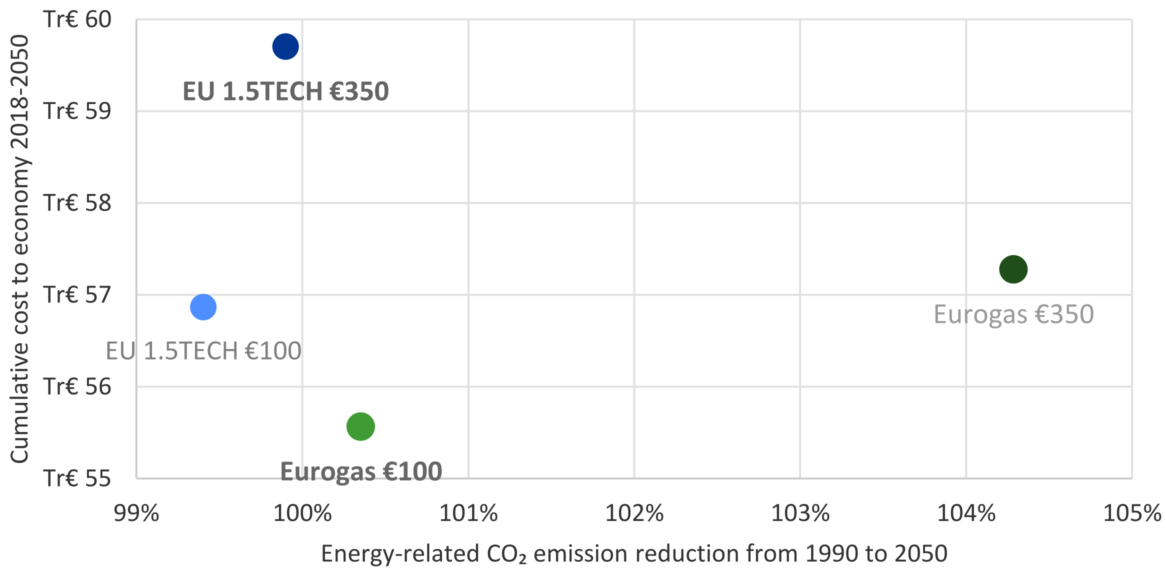

Figure 40 Cost to economy for Eurogas and 1.5TECH scenario with different carbon prices

Figure 40 shows the results for the Eurogas scenario with carbon prices of 100 and 350 €/TCO_2 and similar for the 1.5TECH scenario. The results show that if both scenarios had a similar carbon prices the

Eurogas would be consistently cheaper for society than 1.5TECH. With a carbon price of 350 €/TCO_2 the Eurogas scenario “overshoots” its decarbonization target by 4.3% but still at 4.1% lower cost than 1.5TECH. With a carbon price of 100 €/TCO_2 the Eurogas scenario achieves its net zero objective, while the 1.5TECH scenario fails to achieve full decarbonization.

Still the 1.5TECH scenario is 2.3% more costly to society than the Eurogas scenario at the 100 €/TCO_2 carbon price level (and delivering 100% decarbonization). This led us to conclude that our findings regarding the overall lower cost to the economy for Eurogas scenario are robust.

APPENDIX D

Comparing European energy sector decarbonization pathways

How does the Eurogas scenario contrast with regard to some of the primary alternative scenarios provided? We assessed the high level outcomes of the Eurogas scenario with alternative scenarios that reach Paris compliant decarbonization outcomes in 2050 (95%-100% decarbonization) for the European energy sector. Overall these scenarios depend on very different modelling mechanics and (normative) input assumptions that subsequently deliver (very) different outcomes per scenario.

This comparison provides an overview on some of the critical differences between scenarios, and on some of the key developments that will serve as "sign posts" to develop a decarbonized energy future. Our efforts benefitted from the European Commission's Energy Research Centre (JRC) Technical report *"towards net-zero emissions in the EIU energy system by 2050"*[41], but also required us to dive in the three separate reports to analyse some of the key assumptions and drivers (if available).

In comparison to the Eurogas scenario, two additional scenarios were analysed: the 2018 Eurelectric study on "*Decarbonizing Pathways*"[42] and the 2019 Gas for Climate study on "*The optimal role for gas in a net-zero emissions energy system*"[43]. Both studies aim to achieve a Paris compliant energy sector, with 95 to 100% decarbonization of the energy sector as a proportionate share to achieve economy wide decarbonization in 2050. However, the scenarios have distinctly different ways of achieving this objective, similar to the difference pathways that the Eurogas provides in this study.

Table 6 – Main scope of the three decarbonization studies

	Eurogas	Eurelectric - 95%	Gas for Climate - OGS
Geographical	Global, covering 10 regions, with Europe (EU-27 plus UK, Norway, Switserland and Balkans) as one region	Global, covering 8 regions and the EU28 plus EEA	EU-28
Timeframes	Annual up to 2050, results available for 2030 and 2050	Annual projections up to 2050	Results only for 2050
Sectors	Power, Manufacturing, Buildings, Transport	Power, Industry, Buildings, Transport	Power, Industry, Buildings, Transport
Emissions	Energy-related and process CO2 (incl. intra European aviation and Shipping)	Energy-related CO2 (incl. international aviation)	Energy-related and process CO2 (incl. international aviation)

As the scenarios are developed using different forecasting models, the scope between the scenario's on what decarbonization actually is, where it takes place (geography and sector) and within what timeframe can vary significantly. In the table above the main commonalities and differences on the scope of each scenario are outlined, which indicates that the scenarios are roughly comparable in overall ambition and scope.

[41] Available at: https://ec.europa.eu/jrc/en/publication/towards-net-zero-emissions-eu-energy-system-2050

[42] Available at: https://www.eurelectric.org/decarbonization-pathways/

[43] Available at: https://gasforclimate2050.eu/publications/

Narratives and assumptions of the alternative decarbonization pathways

In addition to the scope of the analysis the overall storyline and assumptions (modelling, technology and economic) between the scenarios can differ considerably, thus influencing the pathway towards the needed decarbonization levels. Below we discuss the main storyline and assumptions driving the Eurelectric and Gas for Climate scenarios.

Eurelectric "Decarbonization Pathways" – 95% decarbonization

The main objective of the Eurelectric study is to assess the role of electrification in transport, buildings and industry to achieve 80-95% decarbonization of the EU economy in 2050. Three scenarios are developed to assess implications for the European Power sector with one scenario (scenario 3) achieving 95% CO2-emission reduction by 2050. To achieve this objective "Major technology breakthrough" are needed.

This scenario implies a need for breakthrough technologies at an early stage of innovation reaching broad commercial scale before 2040. While consumer behaviour assumes high competitiveness of electricity against other energy carriers. Supporting regulation includes the implementation and coordination of decarbonization mechanisms and on a global scale.

Gas for Climate – Optimised Gas Scenario (OGS) – 100% Decarbonization

The study aims to assess a cost-optimal way to fully decarbonise the EU energy system by 2050 and to explore the role of renewable and low-carbon gas used in existing gas infrastructure. Finally the study assesses the cost for society by comparing the OGS against a competing minimal gas scenario (MGS). The main body of the study was launched in 2019, and expanded with specific pathways for renewable gas supply in 2020.

The optimised gas scenario includes a high electrification rate of buildings, industry and transport sectors. Renewable and low-carbon gas is used to provide flexible electricity production, heat to buildings during peak demand, high temperature industrial heat/feedstock and fuel to heavy road transport/international shipping. Hydrogen is produced mainly through electrolysis developed close to large-scale electricity generation sites and is transported using the current gas infrastructure.

Scenario outcomes: Similarities and Differences

The high-level comparison below based on the individual reports available, highlights important differences between the three scenarios when looking at the (direct) electrification rate and gaseous energy consumption of final energy demand. Clearly the Eurelectric scenario's push for direct electrification results in higher share (60%) that the two alternative scenarios. Although the Eurelectric scenario provides limited information on the gaseous energy (still) delivered to customers in 2050, it is clear that this will remain significantly below the 32% of final energy consumption delivered in gaseous from in both the Eurogas and Gas for Climate scenarios.[44]

[44] The Eurelectric scenario does provide for 1200 TWh of indirect electricity consumption in 2050. Needed for energy use related to power-to-X and electricity demand driven by production of biofuels and CCS. If that would be directed to hydrogen production only (at a general 70% efficiency) this would amount to max. ~10% of gaseous energy consumption in the form of hydrogen.

Table 7 – High-level outcomes of the three scenarios

	Unit	Eurogas	Eurelectric - 95%	Gas for Climate - OGS
		2050	2050[45]	2050
Decarbonization	**(% vs 1990)**	**-100%**	**-95%**	**-100%**
Gross Inland Consumption	**(TWh/yr)**	**12.703**	**N/A**	**13.386**
Final Energy Consumption	**(TWh/yr)**	**9.831**	**8.417**	**9.019**
Buildings	(%)	50%	36%	11%
Manufacturing	(%)	22%	40%	16%
Transport	(%)	22%	24%	24%
Electrification[46]	(%)	36%	60%	49%
Gaseous Energy Consumption[47]	(%)	32%	N/A	32%
Gaseous Final Energy Consumption	**(TWh/yr)**	**3.148**	**N/A**	**2.880**
Hydrogen	(%)	57%	N/A	59%
Biomethane	(%)	11%	N/A	41%
Natural Gas	(%)	33%	N/A	N/A
Installed Power Generation Capacity	**(GW)**	**1926**	**2700**	**2795**
Renewable[46]	(%)	84%	83%	96%
Fossil	(%)	13%	~15%[48]	4%
Nuclear	(%)	3%	~2%[49]	0%
Power Generation	**(TWh/yr)**	**5.304**	**7.000**	**7.430**
Renewable[50]	(%)	78%	82%	92%
Fossil	(%)	16%	~5%[44]	8%
Nuclear	(%)	6%	~13%[45]	0%
CC(U)S Deployment	**(MTCO2/yr)**	**1.048**	**200**	**N/A**

Decarbonization

All scenarios focus on decarbonization of the energy sector and assume the efforts in this sector are of a proportionate effort to achieve economy wide GHG-emission reductions put forward in the Paris Climate agreement in 2050.

For 2030 the Eurogas scenario achieves the intermediate goal of 50-55% decarbonization that is now the focus of the “Green deal” in 2030. For the two alternative scenarios it remains unclear whether the 50-55% target for 2030 is achieved. The Eurelectric scenario does not achieve halving of the carbon footprint of power generation in 2030, and as such it is unlikely that overall decarbonization of 50-55% in 2030 is achieved.

Although the Gas-for-Climate 2020 follow up study does indicate that additional efforts are needed to achieve an accelerated 2030 pathway [8], although in the long run net zero emissions are achieved. For 2050 the Eurelectric scenario does achieve a 95% decarbonization target which should be in line with the

[45] Decarbonization projected until 2050, energy data available for 2045
[46] Direct Electricity consumption (excluding Hydrogen produced through electrolysis)
[47] Energy supplied as Biomethane, Natural Gas, and Hydrogen
[48] Natural gas fired power generation only
[49] Nuclear rest of capacity as coal is phased out
[50] Includes Wind, Solar, Hydro, Geothermal and Biomass

Paris Climate agreement objectives, but naturally does not achieve the net zero ambitions now put forward in the European Commission's "Green Deal".

Reduction in final energy demand (energy efficiency)

all scenarios see considerable energy efficiency gains as "Negawats" are arguably the best and easiest way to accelerate decarbonization of energy use. Although, the efficiency achievement are closely related to the technology development and investment cycles in the underlying models and as such can be very difficult to individually compare. Overall, energy efficiency (expressed as annual reduction in final energy demand) in the scenarios needs to be relatively aligned as to see whether decarbonization of the energy sector is overly dependent on "Negawatts" achieved in the future.[51]

The Eurogas scenarios has a -1.2% yearly reduction in final energy demand (over the period 2015 – 2050) while Eurelectric achieves -1.3% per year for the same period. The OGS does not provide a starting point for final energy consumption, but when taking Eurogas scenario final energy demand in 2015 (14.820 TWh) achieves a reduction of -1.4% in yearly final energy demand.

In the Gas-for-Climate study it is clear that massive energy savings are obtained in the building sector to achieve a reduction in gaseous energy usage of about 3600 TWh in 2020 to about 1000 TWh (10% of final energy demand in 2050), which is roughly one third of the amount consumed in the building sector in the other two pathways. This implies that in the OGS relies on massive investments in insulation as it will require nearly all buildings in this scenario to be retrofitted as most remain connected to the gas network.

Power generation

All scenario's see a massive and concerted push to expand renewable power generation resulting in high levels of variable renewable (VRES) power generation. This high penetration of renewables in all the scenarios is driven by both untapped potential and rapidly declining costs for both wind and solar.

Fossil electricity generation decreases in all scenarios (both in capacity and produced) with Eurogas scenario having the largest remaining share in 2050 (which is decarbonized through post-combustion CCS). Nuclear power generation is phased out in the OGS scenario, while continues to provide a mainstay role in all three Eurelectric scenarios. The Eurelectric and Gas-for Climate scenario's achieve similar levels of installed generation capacity (2700 GW versus 2795 GW).

Eurogas scenario reaches the lowest share of renewable electricity production (3056 TWh in 2050) although in installed generation capacity achieves similar shares of renewable electricity (84%) supplied to the Eurelectric scenario (83%). In the Eurelectric scenario natural gas (fossil) fired generation will still contribute 15% of power generated in 2050 (similar to the 13% in the Eurogas scenario) to contribute to system reliability, especially in regions that don't have access to hydro or nuclear.

Electrification and gaseous energy delivery

All scenarios see a clear (but undefined in Eurelectric scenario) cost benefit of continuing gaseous energy supplies to certain economic sectors (e.g. not aiming for a 100% electrification) although for different reasons.

Both the Eurogas and the OGS scenario aim to use the existing natural gas supply infrastructure for all sectors of demand, thus foregoing the additional investment needed in the power grid. In addition, both scenario's include energy use from industrial processes in their forecast which implies a need (and use)

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[51] Overly optimistic (or pessimistic) assumptions on energy efficiency might lead to reduced (or added) need for efforts and increase (decrease) costs, and make the overall decarbonization objectives more easy/difficult to achieve.

for decarbonized feedstocks, that need molecules rather than electrons. Both these scenarios achieve similar shares (32% of final energy demand in 2050) of gaseous energy delivered to consumers.

Eurelectric scenario achieves considerably higher share (60%) of final energy demand delivered as electricity, than the two other scenarios. The Eurelectric study does not provide an amount of energy delivered to consumers as gaseous energy[52]. It does indicate that as power generation is net zero by 2045 and that CCS and other technologies (such as power-to-gas) are needed to balance the electricity supply and offset remaining emissions in other sectors. However, it remains unclear to what extent energy could still be delivered in gaseous form to consumers due to lack of data provided and industrial process decarbonization not included in the study.

Decarbonized gas supply

All scenarios recognize the need for continued use for gaseous energy delivery and use of existing infrastructure though they differ into the extent this is needed. Both the Eurogas scenario and the OGS scenario project similar hydrogen and biomethane supply development with 1783 TWh (blue/green) hydrogen and 1014 TWh of biomethane supplied in the Eurogas scenario, and 1710 TWh of hydrogen and 1170 TWh of biomethane delivered in 2050. Both scenarios have biomethane production through gasification technologies as a core pillar for decarbonization in the scenarios (both staying within the resource limit not competing with alternative biomass uses), and project significant cost savings through economies of scale.

Main differentiator is the significantly higher level of blue hydrogen production in the Eurogas scenario (46% in 2050), while the OGS sees electrolysis arriving as the mainstay for hydrogen production post 2040 delivering. The OGS scenario does not precisely quantify the share of blue hydrogen putting at a possible 190 TWh before the end of 2020's, with a maximum potential of 1500 TWh over the forecasted period (which is not realized). [24]. In the OGS scenario blue hydrogen production is a technology needed to help grow the hydrogen market in the short to medium term. Both scenarios acknowledge that blending hydrogen with methane provides cost efficient ways to decarbonise European gas supply, but acknowledge that hydrogen blending is unlikely to be the optimal solution by 2050.

As mentioned above the Eurelectric scenario this role is limited to a balancing one in support of the power sector with demand for Hydrogen driven by sectors and in need continued support to overcome advantageous power sector economics. While some of these power sector economics overcome by the use of existing gas pipeline infrastructure can be repurposed for power to gas and hydrogen transport and storage. Main requirement would be to take the added benefit of providing flexibility to the power system into account

Role of CCS

all scenarios recognise the role that Carbon Capture and Storage can play in decarbonizing the energy system. Its contribution is however not extensively quantified in the Eurelectric and OGS scenarios.

In the Eurelectric scenario the EU wide uptake of CCs is limited below 200 MT/year. The OGS scenario does not provide a specific level of CCs uptake. Instead the Gas for Climate study provides a potential range of between 190 TWh and 1500 TWh blue hydrogen production (as a proxy for CCS-need) in 2050. Both scenarios contrasts starkly with the Eurogas scenario that sees CCS uptake reach roughly 1 GT/yr in 2050.

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[52] The Eurelectric scenario does provide for 1200 TWh of indirect electricity consumption in 2050. Needed for energy use related to power-to-X and electricity demand driven by production of biofuels and CCS. If that would be directed to hydrogen production only (at a general 70% efficiency) this would amount to max. ~10% of gaseous energy consumption in the form of hydrogen.

Naturally CCS itself is a contentious decarbonization technology with significant societal concerns that will need to be addressed to facilitate expedient uptake and deliver any of the decarbonization benefits (including net negative emissions). In addition to societal and NIMBY, technological maturity and technology cost are a particular factor in each scenario.

In the Eurelectric scenario CCS is considered *"immature and expensive*" it is stressed that "*there are potential synergies in technology development and scale advantages as it is also likely to be needed for other sectors where no other solution is feasible (e.g. abating process emissions in cement production)".*

The Gas for Climate study stresses the technological readiness of CCS (and potential of other capture and use technologies), but does see the uptake as clearly uncertain due to societal objections. However, it does note that if these could be lifted the potential of blue hydrogen is "unconstrained". This is particularly a factor in the short to medium term when CCS is considered a cost effective option versus hydrogen production through electrolysis.

Cost to society

All scenarios consider a decarbonized energy future more costly to society than a Business as Usual scenario (not taking into account the likely devastating effects of climate change on societies) due to an added investment need in the energy sector overall. Costs for society are difficult to compare for due to the different costs used in the model and focus of the studies.

The Eurelectric study focusses on the power sector and indicates that most emissions could be abated at 18-64 Euro/ton, but that the last tons are significantly more expensive (e.g. 130 Euro/ton in the 95% decarbonization scenario). These are costs for the power sector, and as such do not provide an indication of costs in harder to decarbonise sectors such as industry and buildings that are likely to be considerably higher. Overall costs to society are not quantified for the three Eurelectric scenarios.

The Eurogas scenario and OGS scenario derive at different (but significant) costs savings as both are compared to different alternative scenarios (Eurogas is compared to 1.5TECH, OGS to the MGS). In both scenarios most of these costs are not additional costs related to decarbonization, but are regular energy system costs and continuing replacement costs in user sectors that exist today as well. However, both scenario's provide a robust assessment that the continued use of the existing gas supply infrastructure can provide significant cost benefits to society when decarbonizing the overall energy supply system.

The OGS scenario sees average annual cost of 2026 billion Euro per year with 217 billion Euro of yearly savings to society. The Eurogas scenario sees average annual costs of 1670 billion Euro per year with 138 billion Euro of savings compared to the alternative 1.5TECH scenario. Overall, the absolute difference between the Eurogas and OGS scenarios could be explained by the far larger power supply capex required to supply 7430 TWh of electricity to the system (5304 TWh in the Eurogas scenario) in 2050, but quantifying this based on the available data is not possible.

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