



The role of biomethane in creating a climate - neutral industry

An exploratory analysis

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Biomethane demand in industry could grow to 35 bcm by 2050

Significant future biomethane demand in industry

This study assesses the potential demand for biomethane in EU industry. It concludes, based on a comparative analysis of biomethane use compared to one (or in some cases two) viable alternatives in a variety of industrial processes, that a significant volume of biomethane demand in industry is feasible, growing from **~10 bcm in 2030 to ~30 bcm by 2040 and ~35 bcm by 2050**. Seven assessed industrial processes have been analysed, plus broader categories of high, medium and low temperature heat (see next page).

Biomethane can be used in all industrial processes that use natural gas, to supply process heat and carbon-rich feedstock (relevant for example in the chemical sector). It can also be used in primary steel production to replace current use of coal.

To put 35 bcm of biomethane into perspective: current natural gas demand of EU industry totals about 76 bcm, consisting of 69 bcm (718 TWh) of gas used as process energy and 7 bcm (78 TWh) used as feedstock. In addition, 350 TWh of coal is currently used in EU primary steel production that can be replaced by natural gas or biomethane.

Biomethane is not only a climate-neutral source of renewable energy and industrial feedstock but also has the ability to generate negative emissions when combined with carbon capture and storage. This contributes positively to the case of biomethane in industry.

High relevance in steel, high and even low temperature heat

A large share of the potential demand of 35 bcm biomethane by 2050 is associated with the production of primary steel, where biomethane can replace coal in a gas-fired type of steel production plant which is currently not widely used in the EU. Alternatively, hydrogen or natural gas combined with carbon capture and storage can be used in such steel plants.

Other processes with significant biomethane demand are paper production in stand-alone paper mills, ceramics production and the production of ammonia.

A large demand of biomethane can be expected in high-temperature industrial heat. However, biomethane is not only a valuable climate-neutral option to produce high-temperature industrial process heat, but can also be valuable to provide low temperature heat. This segment is often thought to become almost fully electrified, with industrial heat pumps having a superior performance in terms of efficiency. However, in integrated processes (e.g. chemicals),

interconnected heat flows can require multiple heat pumps and process adaptations, increasing implementation complexity.

Electric boilers can be a feasible alternative although their deployment is restricted by the availability of sufficient electricity transmission capacities.



A large part of total biomethane demand is associated with the production of primary steel

Exploratory EU-wide study

This study is an initial EU-wide analysis focusing on nine specific processes: the production of ammonia, urea and methanol (as chemicals), primary steel, aluminium, flat glass, container glass, paper and ceramics. For other sectors, the generation of low, medium and high industrial heat have been assessed in general.

For all assessed sectors, likely alternatives to biomethane have been assessed, including electrification, hydrogen and / or natural gas combined with carbon capture and storage (CCS).

Uncertainties and limitations

The study results are sensitive to assumed energy prices, CO₂ prices and infrastructure costs. Modest future prices are assumed for all energy carriers, as well as modest costs for CO₂ transport and underground storage. It is assumed also that the cost per MWh of both gas and electricity infrastructure will increase (beyond inflation), the increase in power grid cost being higher than those of gas grids. Hydrogen infrastructure costs per unit of energy transported are assumed to be somewhat higher than those for biomethane.

Another large uncertainty is the future total required volume of energy in EU industry. This depends on future industrial production, which in turn depends on factors such as economic growth and EU industrial competitiveness. In this study, a flat industrial production output has been assumed. Future energy demand also depends on energy efficiency gains, which has not been assessed in the present study.

The results of this study are also influenced by the fact that not all of the possible alternatives to biomethane have been assessed for each of the selected industrial processes. Further research into these uncertainties and limitations would be valuable.

Significant demand for biomethane can be foreseen in many industrial processes

Highest potentials in primary steel production, high-temperature heat, and in low- and medium temperature heat processes.

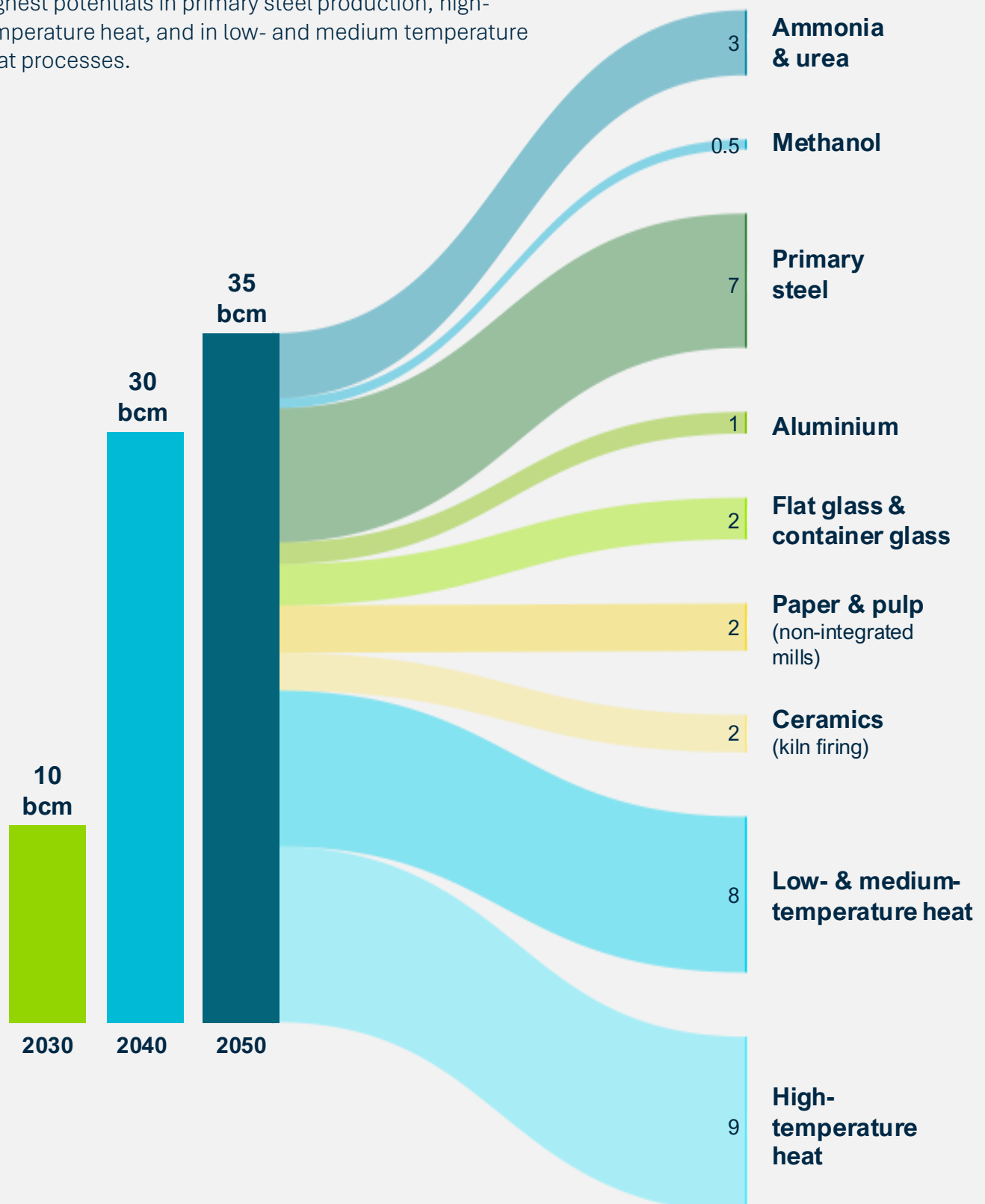


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List of abbreviations

bcm	Billion cubic metres
Al	Aluminium
ATR	Autothermal Reforming
BM	biomethane
BECCS	Bioenergy with Carbon Capture and Storage
CAPEX	Capital expenditure
CO ₂	Carbon dioxide
COP	Coefficient of Performance
CCS	Carbon Capture and Storage
DRI	Direct reduced iron
EAF	Electric Arc Furnace
EU	European Union
EU ETS	EU Emissions Trading System
GJ	Gigajoule
H ₂	(renewable and low carbon) hydrogen
Mt	Million tonnes
MW	Megawatt
MWh	Megawatt hour
NH ₃	Ammonia
SMR	Steam Methane Reformer
TCO	Total Cost of Ownership
TWh	Terawatt hour
WACC	Weighted Average Cost of Capital

A photograph of an industrial facility, likely a refinery or chemical plant, during sunset. The sky is a mix of orange, pink, and blue. Several tall, dark smokestacks rise into the sky. In the foreground, a large, dark, curved pipe runs diagonally across the frame. To the left, there are large, cylindrical storage tanks. To the right, there are complex structures with many lights, possibly distillation columns or reaction vessels. The ground is paved, and there are some vehicles and workers visible in the distance. A solid blue rectangle is overlaid on the bottom left corner of the image.

Chapter 1

Introduction

Introduction

Aim and background of the study

The European Biogas Association (EBA) recently published a Joint Biomethane Declaration signed by a range of European Union (EU) industry associations and companies. The declaration calls for a faster rollout of biomethane and highlights the readiness of industrial companies and sectors to invest in the biomethane value chain.¹ As a next step, the EBA seeks to gain additional insights into the potential future demand of biomethane in nine specific industrial sectors.

Aim of this study

The aim of this study is therefore to analyse, in collaboration with relevant industrial sectors, the **potential for biomethane to help industries achieve net-zero emissions at the lowest possible cost**, taking into account infrastructure-related and other potential constraints.



First-of-a-kind study into the potential role of biomethane in industrial processes

Consideration on how to interpret the study results

This study is a first-of-a-kind study into the potential role of biomethane in industrial processes in the EU. It provides initial insights, focusing on general EU-wide, rather than region-specific, analysis. Often, multiple other options can be used to achieve climate-neutral industrial production, including electrification and the use of renewable or low carbon hydrogen. The chosen solution depends on costs, available infrastructure and the need for conversion of assets and their associated natural investment cycle and is also dependent on operational requirements. We do not assume a binary choice of a certain abatement option by all companies per sector. Rather, we assume that depending on the specific conditions and locations, companies within the same sector may opt for different solutions. Also, various options may be combined as hybrid solutions.

The volumes of potential biomethane demand in industry assessed in this study should therefore not be regarded as *minimum* or *maximum* quantities but rather as indicative quantities that are plausible based

on the assumptions applied in this study. The results should be regarded as an initial evidence base that can be further strengthened through more detailed sector-specific analysis and sensitivity testing.

Background

Since 2005, emissions from industrial installations reduced by 13% and emissions from electricity and heat generation decreased by 54%.³ In total, industrial emissions have fallen by 38% in this period, and by 48% compared with 1990 levels.²

Remaining industrial emissions are about 680 million tonnes of CO₂-equivalent or around 22% of total EU greenhouse gas emissions.⁴

Alongside strategies and regulatory pressure to continue to reduce emissions, industrial sectors are struggling to maintain international competitiveness. Many industrial sectors have experienced reduced industrial output since 2023.⁶ Industries across Europe are considering how to (continue to) reduce greenhouse gas emissions at the lowest possible cost.

A range of solutions to reduce emissions in industry are being applied. So far, applied solutions have focused on energy efficiency, electrification and the use of bioenergy. The first projects for carbon capture and storage (CCS) have also been implemented. Looking ahead, renewable hydrogen is considered as an important energy vector and biomethane and has gained increasing attention in recent years, yet so far has received considerably less attention. This study seeks to contribute to increased understanding of the role biomethane can play.

Biomethane can be used as a net zero emissions option under the EU ETS and can be used in existing gas infrastructure while providing both renewable energy and renewable carbon. In addition to replacing fossil energy carriers in industrial combustion processes, biomethane can play a role as an industrial feedstock, as a flexible energy source complementing electrification, and, when combined with carbon CCS, as a pathway towards negative emissions.

With all of these characteristics, biomethane can play an important role in industrial carbon neutrality, particularly in applications where electrification or hydrogen face technical, economic or infrastructure-related barriers.

¹ Joint Biomethane Declaration. Accelerating Europe's Climate and Industrial Transition with European Sustainable Biomethane (24 March 2026), see: [link](#)

² European Environment Agency, Key trends and drivers in greenhouse gas emissions in the European Union (17 April 2026), Figure 3: Trends in EU GHG emissions by sector, see [link](#).

³ EC Climate Action Progress Report 2025, Figure 10: Emissions under the EU ETS in the EU by sector (Chapter 2), see: [link](#)

⁴ EC Climate Action Progress Report 2025. Commission Staff Working Document. Technical Information (SWD(2025) 347 final), p.43, see [link](#)

⁵ Ibidem, chapter 2, see: [link](#)

⁶ Eurostat, Industrial production (volume) index overview. See [link](#).

⁷ European Biogas Association, 4th Biomethane Investment Outlook (July 2026), see: [link](#)

Introduction

Study scope, general methodology and reading guide

Biomethane production currently is growing by around 20% annually on average across the EU, and EBA data shows significant investment appetite for a further scale up in the coming years.⁷ Yet despite the growing attention for biomethane, there is currently no comprehensive assessment of its potential role across European industry. Existing studies primarily focus on biomethane production potential, overall gas demand, or individual sectors, while comparatively limited attention has been given to identifying the industrial applications in which biomethane delivers the greatest value relative to alternative pathways to climate neutrality.

This study addresses this knowledge gap by providing a structured and evidence-based assessment of the potential role of biomethane in industrial emission abatement across Europe. As a foundational study, it establishes a common analytical framework for evaluating industrial demand for biomethane across sectors and applications. Rather than assuming that current natural gas demand will simply transition to renewable gas, the study identifies those applications where biomethane represents a technically feasible, economically attractive and strategically valuable decarbonisation option. The findings are intended to support policymakers and industry stakeholders in understanding where biomethane can contribute effectively to achieving Europe's industrial climate neutrality objectives. This study also provides a solid basis for future, more detailed assessments of specific industrial sectors, technologies or national markets.

Study scope

The study assesses the role of biomethane in achieving climate-neutrality in industrial production across the EU.

The assessment considers as time horizons 2030, 2040 and 2050, and, for each of these years, analyses the costs of biomethane compared to viable alternatives.

The analysis focuses on **primary or base industry sectors** that uses raw materials to produce semi-finished goods. Secondary manufacturing industries that uses these goods to create final products (e.g. automotive, consumer electronics and aerospace industries) are not assessed explicitly yet are covered under the general categories 'low', 'medium' and 'high' temperature heat. Within primary industry, the study focuses on specific industrial processes with significant current or potential demand for gaseous energy carriers and renewable carbon molecules. In some cases, the selected processes match rather well with the full scope of a sector. In other cases, only part of a sector is covered.

Selected industrial processes

This study analysis covers chemicals (ammonia, urea fertiliser and methanol production), glass (both flat glass and bottles), ceramics, primary steel, pulp and paper and aluminium.

Together, these industries represent a diverse range of thermal energy requirements, feedstock uses and process characteristics that are relevant for assessing biomethane deployment. To also cover other sectors, this study analyses as general pathways high, medium and low temperature heat production.

All of these industrial processes have been selected from a long-list on the basis of the assumed feasibility to deploy significant quantities of biomethane as a climate-neutral energy carrier or provider of industrial feedstock and on the basis of willingness by their relevant EU sector associations to provide input to this study and discuss key assumptions.

In most cases biomethane replaces natural gas in existing production processes, yet in primary steel production biomethane would replace current use of coal and bit of natural gas, which requires new production installations.



Introduction

Study scope, general methodology and reading guide

Chapter 4 below provides a description of each of the analysed industrial processes including key parameters and assumptions plus the main outcomes of the analysis for each process.

In addition to energy used in selected sectors, this study also covers gas used for industrial feedstocks. This is mainly relevant for ammonia production, where a substantial part of current natural gas consumption is used as feedstock rather than for process energy. For urea production (which uses ammonia and CO₂ as inputs) the share of feedstock energy is even higher.

High-level study methodology

Recognising that energy transition choices are primarily determined by process requirements, the assessment adopts an application-based approach.

The analytical approach combined desk research, quantitative demand assessment, policy and market analysis, stakeholder consultation and price scenario analysis.

Industrial demand is evaluated through a sequential assessment of technical potential, addressable demand, and realistic market uptake, reflecting narrowing from theoretical demand to economically viable deployment.

The assessment further considers infrastructure compatibility, technology readiness, transition costs, and the strategic value of biomethane within future industrial energy systems, including its contribution to renewable carbon provision, system flexibility and negative emissions through biogenic CCS (BECCS).

Consulting with sector associations

As part of this study, Common Futures and Guidehouse have consulted several EU sector associations that collectively represent the industrial processes in scope. These include CEFIC (ammonia, urea, methanol), CEPI (pulp and paper), CEFS (sugar, relevant for 'low temperature heat' analysis), Cerameunie (ceramics), Eurofer (steel), Eurometaux (aluminium and other metals), European Aluminium (aluminium), Fertilisers Europe (ammonia, urea), Glass for Europe (flat glass), FEVE (glass packaging). In addition, Cogen Europe and IFIEC Europe were consulted because of their expertise on industrial energy production and consumption.

For all sectors that are explicitly covered in this study, the relevant associations have had the opportunity to review the draft results. The input and feedback of

these associations has greatly helped to ensure accurate and robust study results.

It should be noted that Common Futures and Guidehouse are fully responsible for all assumptions, methodological choices and analysis results.

Reading guide

The remainder of this report is organised as follows.

Chapter 2 describes the methodology used to assess potential demand for biomethane in the selected processes and introduces the application-based approach adopted throughout the study.

Chapter 3 describes the analysis performed and the main study results and recommendations for further research.

Chapter 4 presents the Industry Factsheets, describing the insights from application-based analyses into industrial demand for biomethane across the selected sectors.



Chapter 2

Methodology

Biomethane as part of the industrial transition

The transition towards climate-neutral industrial production will require a combination of solutions. No single abatement measure is expected to meet the full range of industrial needs. Instead, different solutions will play different roles in emission abatement across sectors, applications and individual production sites.

Five broad groups of abatement solutions can be identified:



1. Energy efficiency can reduce industrial energy demand through measures such as process optimisation, heat integration and waste-heat recovery. At a large chemical production site in Belgium, for example, optimisation measures across several production plants reduced the consumption of natural gas, hydrogen and steam, avoiding more than 38,000 tonnes of CO₂ emissions annually.



2. Electrification can replace fossil fuel consumption where industrial processes can be supplied directly with electricity. At a milk-powder production facility in Denmark, for example, a high-temperature electric heat pump was introduced to replace natural gas in the heat supply for spray drying, reducing annual CO₂ emissions by more than 1,500 tonnes.



3. Renewable gases can play a role where gaseous energy carriers or feedstocks remain necessary. Different renewable gases can fulfil different functions. At a refinery in Germany, for example, a 10 MW electrolyser has produced **renewable hydrogen** for integration into existing refinery processes since 2021, demonstrating the replacement of part of the conventionally produced hydrogen used at the site. Biomethane can provide a more direct substitute for natural gas. At a flat-glass production facility in France, locally produced **biomethane** was successfully used in the glass production process in 2025, demonstrating its potential to replace fossil natural gas while retaining a gaseous production route.



4. Carbon capture and storage (CCS) can address emissions that are difficult to avoid through changes in energy supply alone. At a cement production facility in Norway, an industrial-scale carbon capture installation became operational in 2025, with the capacity to capture and permanently store around 400,000 tonnes of CO₂ annually, equivalent to approximately half of the plant's emissions.



5. Hybrid solutions can combine different (sustainable) energy carriers within the same industrial process. At a paper production facility in the Netherlands, for example, an electric boiler has operated alongside the existing steam boiler since 2025. The hybrid configuration allows steam to be produced using electricity when available, while retaining the existing boiler for flexibility and security of supply.

These solutions are often not mutually exclusive. In many cases, they are likely to be applied alongside one another, either within the same sector or potentially within the same industrial site.

The relative role of these solutions will differ between industrial applications. Cost is an important factor, but it is not the only one. Technology maturity, availability of energy and infrastructure, compatibility with existing assets, operational requirements, security of supply and the timing of natural reinvestment cycles can all influence which solution is most appropriate at what point in time.

Methodology for assessing the potential role of biomethane in industry

This study assessed the potential role of biomethane in (the transition towards) a climate-neutral European industry by examining where biomethane can provide a technically feasible and economically attractive abatement solution. The analysis takes an application-based, bottom-up approach, and was performed for three assessment years: 2030, 2040 and 2050.

The analysis covers selected applications in the chemicals and fertiliser, primary steel, aluminium, glass and ceramics, and pulp and paper industries, as well as generic industrial heat applications. Applications were selected based on their current or potential use of gaseous energy carriers and the possible role of biomethane in reducing fossil greenhouse gas emissions. The selection and characterisation of applications and relevant alternative technologies were informed by literature research and consultation with European industry associations.

For each application, the analysis follows five main steps:

1. **Establish the industrial baseline**, based on current production volumes, production processes and associated energy demand.
2. **Determine the share of production transitioning towards climate-neutrality** in 2030, 2040 and 2050, based on an assumed EU industrial emission-reduction trajectory.
3. **Assess relevant climate-neutral production routes**, including a biomethane-based route and the most relevant alternative pathway(s). Each route was assessed on cost competitiveness (relative to a fossil-based reference route), technical readiness, infrastructure readiness and asset compatibility.
4. **Compare the climate-neutral production routes and estimate their relative shares** by combining the results of the route assessment. This resulted in an estimated share of climate-neutral production allocated to the biomethane route for each application and assessment year.
5. **Translate the application-level results into potential biomethane demand and aggregate them across sectors**, followed by a cross-sector consistency check of the resulting demand estimates.

The resulting demand estimates should be interpreted as an assessment of the potential industrial uptake of biomethane under the assumptions used in this study, rather than as a forecast of future biomethane consumption.

The remainder of this chapter describes each methodology step in more detail.

Study methodology

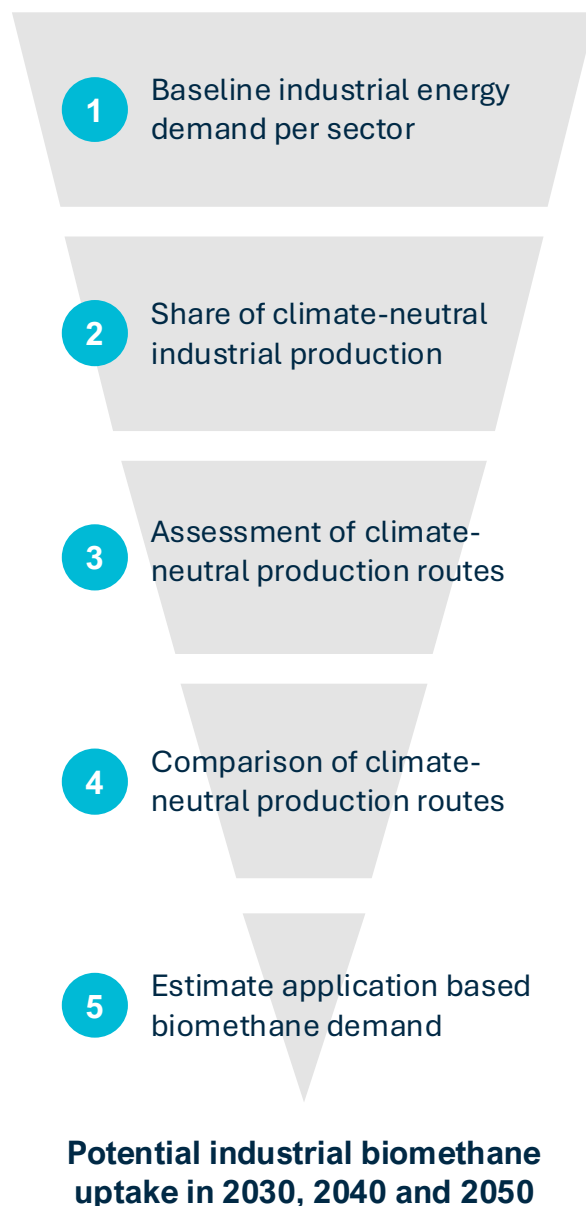


Figure 1. Methodology to assess potential industrial uptake of biomethane in Europe in 2030, 2040 and 2050.

1. Establishing the industrial baseline

The starting point for the analysis was a quantitative baseline of industrial activity and energy demand for each selected application. The baseline reflects industrial production in 2025 and identifies the energy and feedstock requirements associated with the relevant production process.

The analysis assumes constant industrial output at 2025 levels towards 2030, 2040 and 2050. This deliberately simplifies the analysis and isolates the effect of changes in production routes from assumptions about future growth or decline in European industrial production.

For most applications, current natural gas demand provides the starting point for estimating the scale of energy demand that could potentially be supplied by biomethane. However, this does not imply that all current natural gas consumption is assumed to transition to biomethane. Subsequent analytical steps determine which share of production transitions away from unabated fossil production and how biomethane performs relative to the alternative routes available for that application.

For some applications, the transition to carbon-neutral production itself can create new demand for gaseous energy carriers. Primary steel production is an important example. Most European primary steel is currently produced through the coal-based blast furnace-basic oxygen furnace route. A transition towards direct reduced iron (DRI) creates potential demand for either methane or hydrogen as a reducing gas that is not present in the current natural gas demand baseline.

2. Estimating the share of climate-neutral industrial production

The next step determined the share of industrial activity that transitions away from unabated fossil production in each assessment year for each industrial application. The analysis applied an emission reduction trajectory towards carbon-neutral industry, presented in the table below. For 2030, 2040 and 2050, this trajectory determined the share of industrial production that transitions to a climate-neutral production route for the respective assessment year, compared to the 2025 baseline. The remaining share of production was assumed to remain on the unabated fossil reference route.

The specific percentage of emission reduction by 2030 is based on the current trajectory with which the EU ETS emission ceiling has to decrease. For 2040, this study uses the amended trajectory as proposed by the European Commission on 17 July 2026 (COM/2026/616). Full climate neutrality in EU industry is assumed well before 2050 (2050 in this study).

2030	2040	2050
23%	74%	100%

Table 1. Assumed share of industrial production transitioning to climate-neutral production in each of the assessed years, compared to the 2025 baseline in this study.

In this analysis, the demand for biomethane is assessed as one of the solutions for the share of industrial production transitioning away from unabated fossil production. The approach reflects the progressive nature of the industrial transition. Industrial installations typically have long technical lifetimes and are not replaced simultaneously. Applying an increasing transition share over time therefore provided a simplified representation of the gradual transformation of Europe's industrial asset base.

3. Assessment of production routes

For each industrial application, the identified production routes were assessed against a common set of criteria. The assessment combined a detailed quantitative analysis of the cost competitiveness of each route with three non-cost factors: technical readiness, infrastructure readiness and asset compatibility. Together, these factors provided the basis for subsequently comparing the production routes and estimating their potential share of climate-neutral production.

The routes assessed differed by application, reflecting the specific technical requirements of each industrial process. In each case, the analysis included a conventional fossil production route as the reference, a biomethane-based route, and the most relevant alternative climate-neutral production route or routes. Depending on the application, these alternatives included electricity- or hydrogen-based routes.

		Reference	Biomethane	Electricity	Hydrogen
1/2	Ammonia (+ urea)	SMR (NG) + Haber Bosch	SMR (BM) + Haber Bosch		Green or blue H ₂ + Haber Bosch
3	Methanol	NG > synthesis gas > methanol	BM > synthesis gas > methanol		Green H ₂ + CO ₂ > methanol
4	Primary Steel	BF-BOF (coal based)	DRI + EAF (BM based)		DRI + EAF (green H ₂ based)
5	Alumina refining	Gas boiler using NG	Gas boiler using BM	E-boiler	
6/7	Glass (Flat glass & container glass)	Gas furnace using NG	Gas furnace using BM	Electric furnace	
8	Paper and pulp (Non-integrated mills)	Gas boiler using NG	Gas boiler using BM	1. Electric heat pump 2. E-boiler	
9	Ceramics (Kiln firing)	NG-fired kiln	BM-fired kiln	Electric kiln	
10	Low temp. heat	Gas boiler using NG	Gas boiler using BM	Electric heat pump	
11	Medium temp. heat	Gas boiler using NG	BM-fired furnace or oven	Electric boiler or furnace	
12	High temp. heat	Gas furnace using NG	Gas furnace using BM	Electric furnace	Gas furnace using green H ₂

Figure 2. Overview of the applications included in the study and the analysed reference and climate-neutral production routes.

Cost competitiveness

Cost competitiveness formed the most detailed component of the route assessment. A Total Cost of Ownership (TCO) model was developed for each application and production route to consistently compare the costs associated with the fossil reference route, the biomethane route and the relevant alternative route(s).

The TCO calculation incorporated the cost elements and technical parameters that materially differed between the assessed production routes. Depending on the application and route, these included:

- **Capital Expenditure (CAPEX)**, including relevant production equipment, process modifications and installation;
- **Weighted Average Cost of Capital (WACC)**, used to annualise capital expenditure (assumed to be 10% for all sectors);
- **Asset lifetime**, determining the period over which investments were annualised;
- **Energy intensity**, reflecting the gaseous fuel and electricity requirements per unit of product
- **Feedstock intensity**, reflecting the energy carriers used as a production feedstock rather than fuel.
- **Emission intensity**, reflecting the greenhouse gas emissions associated with production

- **Capture rate**, where applicable, reflecting the amount of CO₂ captured, transported and stored per unit of product.

These technical parameters were combined with assumptions on energy prices, carbon prices and infrastructure costs to derive the costs of emission abatement of each climate-neutral production route relative to the conventional fossil reference. The analysis included annualised CAPEX, energy and feedstock expenditure, relevant infrastructure and network costs, and carbon costs. Non-energy operational expenditure was excluded from the analysis as it was not expected to significantly differentiate between production routes.

Non-cost factors

The economic assessment was complemented by three **non-cost factors**, recognising that industrial technology choices are not determined by production costs alone. The non-cost factors included are 1) technical readiness, 2) infrastructure readiness and 3) asset compatibility.

1. *Technical readiness* assessed the maturity and commercial availability of each production route in the respective assessment year. Technologies that were already proven at commercial scale received higher scores than technologies requiring further demonstration, development or scale-up.

Box 1. Energy and carbon price assumptions

Energy and carbon prices represent key inputs for the TCO calculation. Given the inherent uncertainty surrounding long-term commodity prices, the assumptions applied in the analysis are not intended to be forecasts. Instead, they are intended to represent plausible price assumptions that enable the relative economics of different production routes to be consistently compared in 2030, 2040 and 2050.

The **main price set** presented below formed the basis for the central analysis and the potential biomethane demand presented in the main results. It assumes a constant long-term natural gas price, and relatively optimistic declining electricity and green hydrogen prices towards 2050, and relatively stable biomethane prices.

A second **sensitivity price set** was used to test the results under conditions relatively more favourable to biomethane, with higher long-term electricity and green hydrogen prices and a lower biomethane price in 2050. The model also allowed individual commodity prices to be varied independently. Where relevant, these sensitivities were used to test the robustness of conclusions on cost competitiveness.

The price assumptions were developed using a combination of public market information, external energy scenarios, published studies, previous analysis and expert judgement. The **Annex** provides a detailed description of the underlying price ranges, sources and assumptions, and explains how these were translated into the main and sensitivity price sets.

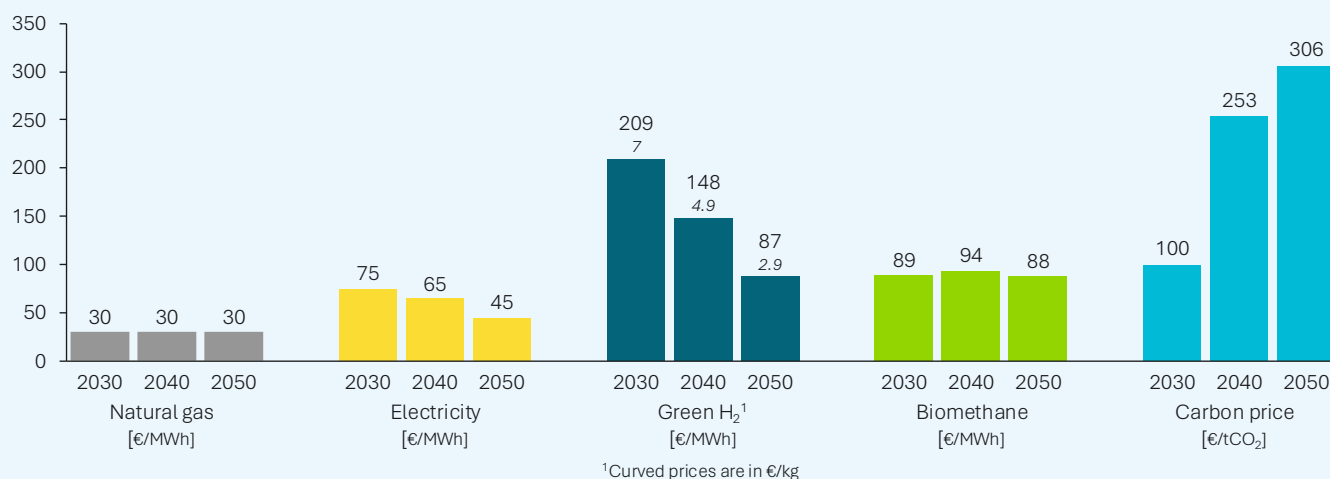


Figure 3. Assumed energy and carbon prices in 2030, 2040 and 2050.

Box 2. Infrastructure costs

Infrastructure costs were also included in the TCO calculations. These costs reflect the use of energy and CO₂ infrastructure beyond the industrial site and were treated separately from commodity prices.

For natural gas and biomethane, gas network and storage costs were included, with biomethane assumed to use the existing gas network under the same network-cost assumptions as natural gas. For electricity, network costs were added to electricity consumption and were assumed to increase towards 2050, reflecting the investment required to expand and reinforce European electricity grids. For CO₂, costs depended on its use: CO₂ supplied as a carbon feedstock included transport costs, while captured CO₂ destined for permanent storage included both transport and storage costs. Further details on the infrastructure cost assumptions and sources are provided in the **Annex**.

Infrastructure costs		2030	2040	2050
Natural gas /biomethane	€/MWh	7	8	10
Electricity	€/MWh	22	27	36
Hydrogen	€/MWh	21	21	21
CCU (transport)	€/tCO ₂	51	51	51
CCS (transp. & storage)	€/tCO ₂	60	60	60

2. Infrastructure readiness assessed the availability of the infrastructure required for each production route. Biomethane infrastructure was assumed to be available throughout the assessment period, leveraging the existing natural gas grid. Electricity, hydrogen and CO₂ infrastructure were assumed to develop towards 2050. By 2050, hydrogen and CO₂ infrastructure was assumed to be available, but not necessarily at all industrial sites. Reinforced electricity infrastructure was assumed to be sufficiently available in industrial clusters, while availability at more remote locations could remain constrained, particularly for paper and glass production.

3. Asset compatibility assessed the extent to which a production route can make use of existing industrial production assets. Routes that can be implemented with relatively limited modifications to existing installations received higher scores than routes requiring major retrofits or replacement of core production equipment. This criterion was particularly relevant in applications where biomethane can substitute fossil natural gas while retaining substantial parts of the existing production process.

Each production route was scored on the three non-cost criteria for 2030, 2040 and 2050. Allowing the analysis to reflect changes over time in the expected development of technologies and supporting infrastructure.

4. Comparison and allocation across production routes

Following the assessments of the individual routes, the results were brought together to compare the available climate-neutral production routes within each industrial application.

The comparison combined the four criteria assessed in the previous step. For each criterion, the performance of the production routes was translated into a score on a common scale. For technical and infrastructure readiness, the 2030 assessment first considered whether the required technology or infrastructure was available. Their subsequent development towards 2050 was reflected using a 0–4 scoring scale.

	Technical readiness	Infrastructure readiness	Asset compatibility	Cost competitiveness (TCO)
0	Highly unready	Unavailable	Incompatible	Highly uncompetitive
1	Unready	Major gaps	Major rebuild	Uncompetitive
2	Moderate	Constrained	Significant retrofit	Moderate
3	Available	Available	Minor retrofit	Competitive
4	Proven	Mature	Directly compatible	Highly competitive
	Weighting 20% <i>Knock-out criterion: if the score is 0 the pathway is scored 0</i>	Weighting 15% <i>Knock-out criterion: if the score is 0 the pathway is scored 0</i>	Weighting 15%	Weighting 50%

Figure 4. Scoring criteria and weighting for the production route assessment.

Chapter 2. Methodology

The weighted scores were then combined to obtain an overall score for each route. Cost competitiveness, informed by marginal abatement cost analysis, received a weight of 50%. Technical readiness accounted for 20%, while infrastructure readiness and asset compatibility each accounted for 15%. The routes were then assessed relative to the alternatives available for the same industrial application.

The resulting relative scores were used to estimate how the share of production transitioning away from unabated fossil production (as defined in Step 2) could be distributed across the available climate-neutral production routes. For example, where the biomethane route accounted for 40% of the combined scores of the available climate-neutral routes, 40% of the transitioning production volume was allocated to the biomethane route. The remaining volume was allocated across the other assessed routes according to their relative scores.

The route assessment focused on the main climate-neutral production routes considered most relevant for each application and did not necessarily capture all possible alternatives. For sectors where additional climate-neutral production routes could play a relevant role, 30% of the transitioning production volume was therefore reserved for these non-modelled routes. The remaining 70% was allocated across the routes assessed in detail according to their relative scores. This adjustment was applied only in sectors where relevant additional routes were identified. This '30% reservation' means that the present study results can be considered as conservative, avoiding a situation in which volumes would significantly decrease in a follow-up study that analyses additional alternative abatement options.

The estimated shares can change between 2030, 2040 and 2050 as energy prices, technology maturity, infrastructure availability and asset compatibility evolved. The outcome of this step was an estimated biomethane share of climate-neutral production for each industrial application and assessment year. This share was subsequently combined with the production volume transitioning away from unabated fossil production and the application-specific biomethane intensity to calculate potential biomethane demand in the specific industrial application.

$$\text{Potential application-specific biomethane demand} = \text{industrial activity} * \text{climate-neutral production share} * \text{biomethane route share} * \text{biomethane intensity}$$

5. Aggregation and cross-sector validation

In the final step, the resulting application-level estimates were aggregated across all applications included in the study. This provided an estimate of potential European industrial biomethane demand in 2030, 2040 and 2050.

In addition, the results were reviewed across sectors and applications to assess their consistency and relative plausibility. This cross-sector review considered whether differences in estimated biomethane uptake could be explained by the underlying technical and economic characteristics of the applications and whether the resulting allocation remained consistent when applications were compared with one another. Where this review identified inconsistencies that were not sufficiently reflected in the initial scoring, selected assumptions or scores were refined.

This final review was intended as a consistency check rather than a separate modelling step. It ensured that application-level assessments, which were necessarily developed using sector-specific evidence, resulted in a coherent overall picture when combined across European industry.



A photograph of a large industrial facility, likely a refinery or chemical plant, at night. The scene is illuminated by bright artificial lights, creating a high-contrast image. In the foreground, there are several large, white, cylindrical storage tanks or reactors, connected by a complex network of pipes and metal walkways. A prominent vertical pipe runs through the center of the image. To the right, another tall, cylindrical structure is visible. The background shows more industrial equipment and a dark sky. A semi-transparent white box is overlaid on the left side of the image, containing the chapter title and subtitle. A large, curved yellow shape is in the bottom right corner.

Chapter 3

Feasible industrial biomethane demand

Overview of results

Overall analysis results

EU industry currently uses more than 1,000 TWh of process energy and feedstock that can be replaced by biomethane. This total volume of energy consists of 718 TWh (69 bcm) of natural gas used as process energy, 78 TWh (7 bcm) of natural gas used as feedstock and 350 TWh of coal used in steel production¹.

It is uncertain how this demand will develop over time. On the one hand, economic growth may drive an increased demand for industrial commodities, on the other hand, it remains uncertain to what extent production of these commodities will continue to take place within the EU. In this study the simplified assumption is used that demand will remain flat

The analysis performed in this study following the methodology set out in chapter 2 shows that when comparing biomethane consumption in industry to feasible alternatives, under the assumptions used in this study a biomethane demand is feasible of 10 bcm by 2030, ~30 bcm by 2040 and 35 bcm by 2050. This biomethane is predominantly used in primary steel production, chemicals (mainly ammonia, urea), paper production, ceramics and high and low temperature in general. Smaller quantities can be foreseen in the production of primary aluminium, methanol and glass, as can be seen in the graph to the right.

Strong electrification is foreseen alongside biomethane, plus a role for hydrogen and CCS. Electrification is driven by assumed modest electricity costs and relative high efficiency of industrial heat pumps. On the other hand, there are cases where electrification would not be the option of choice due to operational and infrastructural constraints. The analysis shows that process heat temperature alone does not determine whether electrification is the preferred route; process integration, infrastructure and asset compatibility can be equally decisive. This is further explained on p.28 below.

The value of biomethane is not limited to energy substitution. In urea and methanol, its embedded biogenic carbon can avoid the need to procure a separate renewable CO₂ feedstock.

The sections below provide the main results of the analysis of each of the industrial processes. For each, a brief general description is provided, along with an assessment of how current consumption of natural gas (or coal in the case of steel) can be replaced by biomethane or other climate-neutral solutions, how these abatement options compare, and what this implies for potential biomethane consumption.

Model results on potential demand for biomethane per sector

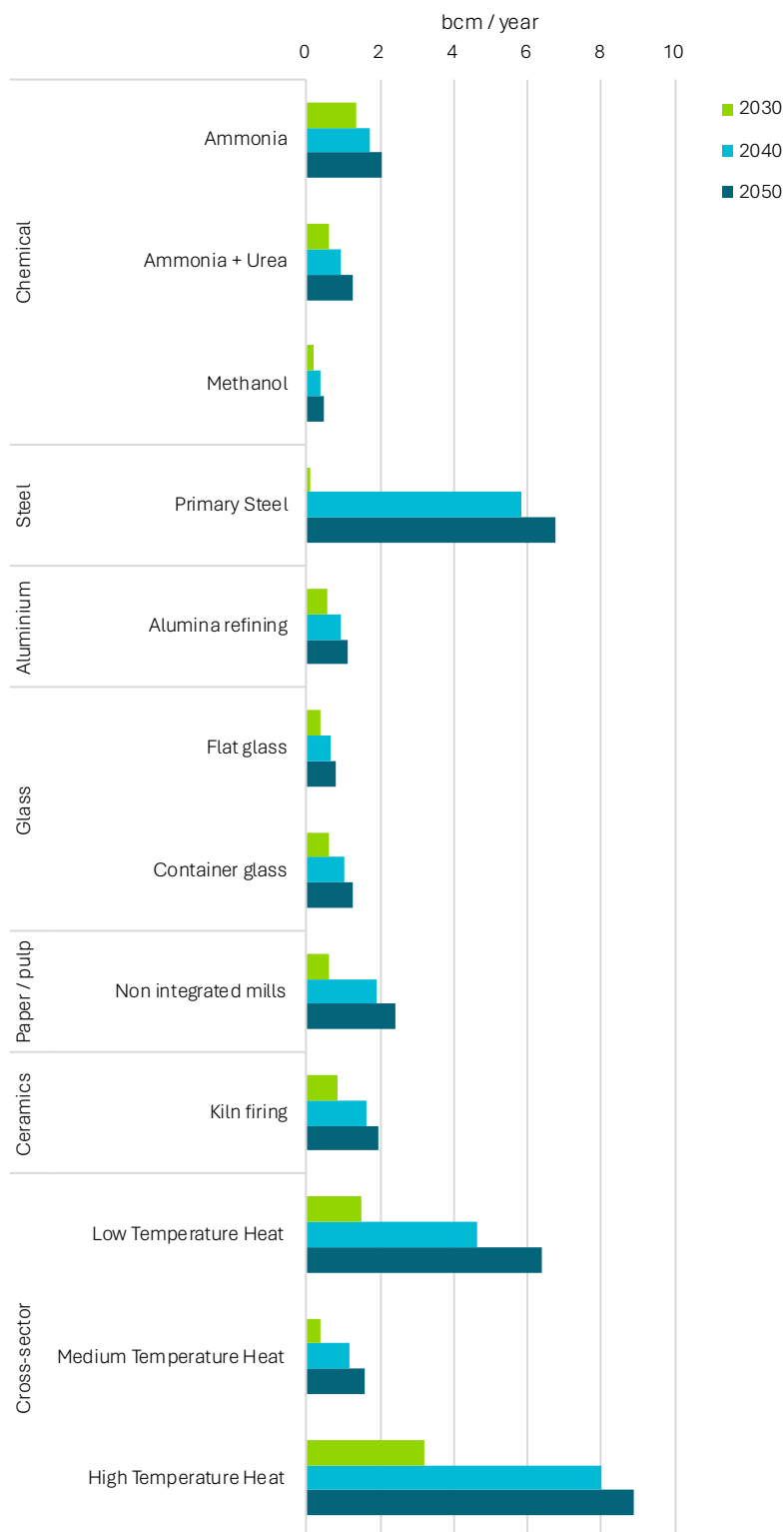


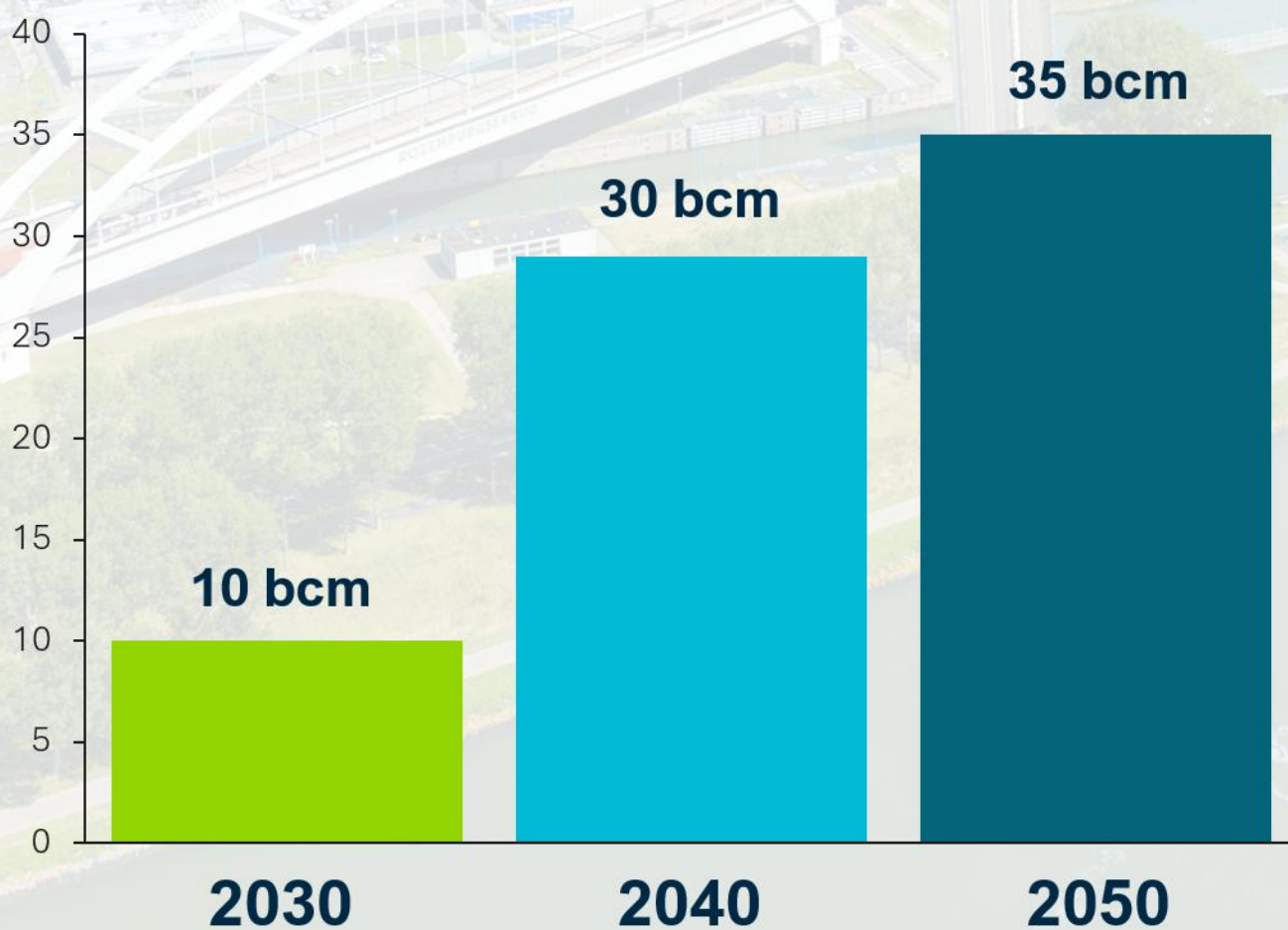
Figure 5. Model results on potential biomethane demand in each sector for 2030, 2040 and 2050.

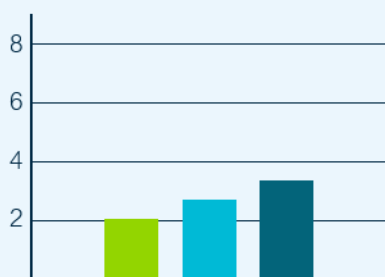
¹ Eurostat Energy Balances (27 countries). See: [link](#).

Note: Sectoral natural gas demand for process energy & feedstocks has been established using insights provided by various sector association.

Growing role for biomethane

35 billion cubic metres of biomethane demand in EU industry is feasible by 2050. This corresponds to about one-third of current EU industrial consumption of natural gas (& coal used for basic iron production).





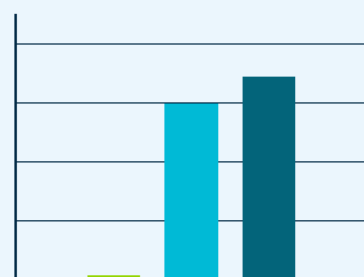
Ammonia & urea

Both require significant carbon-feedstock and process energy. For ammonia, CCS can provide both at the lowest costs. Urea requires CO₂ as input. As CCS provides fossil CO₂, biomethane is the least-cost fully renewable option.



Methanol

Requires process energy and carbon-rich feedstock. For fully climate-neutral methanol, including embedded carbon, biomethane is the lowest-cost abatement option.



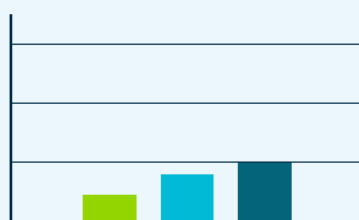
Primary steel

Primary steel is expected to shift from coal-based production towards cleaner gas-based units. Biomethane can be used in those installations and is attractive in the near term, while hydrogen becomes increasingly competitive towards 2050.



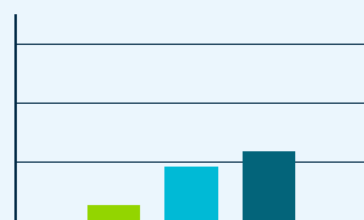
Aluminium

The refining of alumina is a high-temperature process that can be electrified. That route has the lowest costs. Biomethane will only be applied at locations where electrification doesn't fit with the natural investment cycle.



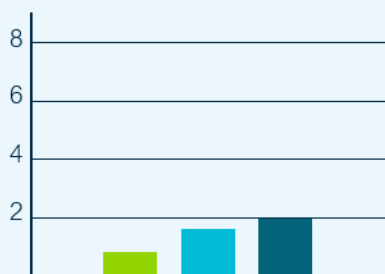
Flat & container glass

Requires high-temperature heat with strict quality requirements. Electrification is not yet technically suitable but could become the preferred long-term solution. Biomethane offers natural gas-equivalent performance and is particularly valuable on locations where sufficient renewable power is unavailable.



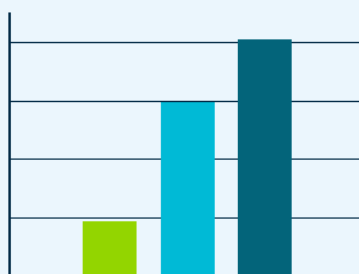
Paper

Non-integrated paper mills without own pulp production require large volumes of externally sourced energy to provide low-temperature heat. This can be effectively electrified, and biomethane can be used at remote locations without sufficient access to large capacities of electricity.



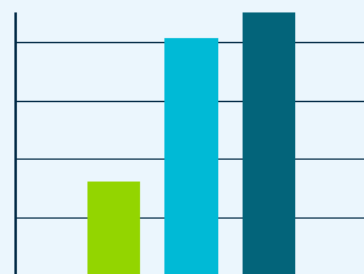
Ceramics

Requires high-temperature heat, with waste heat being re-used in the process. Electric furnaces are possible yet require significant asset investments. Biomethane can be integrated seamlessly.



Low-/medium-temp. heat

Electrification generally offers the lowest costs, especially for low-temperature heat due to efficient heat pumps. Biomethane remains relevant where process integration or grid constraints limit electrification. At medium temperatures, costs are more comparable due to smaller efficiency gains from electric boilers.



High-temp. heat

Biomethane can replace natural gas seamlessly. Electrification furnaces can play a role too, by 2050 having the lowest costs. Large volumes of biomethane expected to be used, including at remote locations connected to the gas grid

Ammonia

Ammonia production is among the most energy- and carbon-intensive processes in the chemical industry. In the process, hydrogen is produced (currently from natural gas) which is turned to ammonia in the 'Haber-Bosch process'. About 6 bcm of natural gas is currently used annually for process energy and as feedstock input.

In achieving climate-neutral ammonia production, biomethane 'competes' with carbon capture and storage (CCS) and the use of hydrogen. CCS is the most cost-competitive option throughout the period 2030-2050. Capturing CO₂ in parts of the ammonia production process is relatively straightforward and is already applied, with captured CO₂ being sold to other industries. Some emissions remain however, which can be mitigated by the use of biomethane. The use of biomethane initially is more cost-competitive (after CCS) compared to hydrogen, yet by 2050 using hydrogen is assumed to have lower total costs. Whereas the biomethane route fits well with the availability of gas infrastructure, the CCS and hydrogen routes are dependent on infrastructure that is still to be developed. It is assumed that both infrastructures will emerge throughout Europe, however it is uncertain whether all of the just over 30 ammonia production facilities will be connected to CO₂ and/or hydrogen infrastructure. For this reason, it is assumed that biomethane to be used in some of the facilities, starting from around **1.5 bcm** in 2030, growing to **about 2 bcm** in 2040 and **2 bcm** by 2050.

Urea

Urea is widely used as nitrogen fertiliser in the agricultural sector and is produced from ammonia and captured process-CO₂. As with ammonia, natural gas is used both as process energy and as feedstock input. Current natural gas consumption is 2.5 bcm annually.

Various routes exist to make urea production climate neutral. In this study, biomethane and green hydrogen are analysed, as well as applying carbon capture and storage to existing natural gas-based production.

Whereas in ammonia production applying CCS is the most cost-competitive route to climate-neutrality, this doesn't apply to urea under the assumptions used in this study. The reason for this is that urea production requires CO₂, which would need to be renewable in the future. When applying CCS, fossil CO₂ is captured and stored while at the same time (expensive) renewable CO₂ has to be purchased. Biomethane can replace natural gas and is a source of renewable biogenic CO₂. Using biomethane is the most cost-effective abatement option in urea production, followed by CCS; hydrogen comes last. As with CCS, the route using externally sourced green hydrogen is expensive because renewable CO₂ has to be externally sourced. Biogenic CO₂ can be sourced from biomethane, yet producers can also sell their CO₂ to a party that will use it for CCS to generate negative emissions. In this study, it is assumed that the

maximum price for biogenic CO₂ consists of the EU-ETS allowances price.

This is an additional cost to the CCS and hydrogen routes. Biomethane demand could be **about 0.5 bcm** in 2030, growing to about **1 bcm** in 2040 and **1.5 bcm** by 2050.

Climate-neutral urea (and ammonia) can from an EU ETS perspective still contain fossil feedstock CO₂, yet the agricultural and other sectors also need to achieve climate neutrality and will demand climate-neutral feedstock CO₂. In this analysis, it is assumed that ammonia and urea production are produced with renewable CO₂. We have assumed the same for methanol production (described below).



Whereas in ammonia production applying CCS is the most cost-competitive route to climate-neutrality, this doesn't apply to urea

Methanol

Methanol is an important chemical building block and can also be used as (maritime) fuel. It is produced from natural gas that is converted into synthesis gas (hydrogen and carbon monoxide), which is subsequently converted into methanol. As with the ammonia and urea pathways, natural gas is used for process energy as well as for feedstock. Currently, the sector consumes about 1.2 bcm of natural gas.

The two options to achieve climate-neutral methanol production are replacing natural gas with biomethane and using green hydrogen to produce 'e-methanol'. Out of these two, biomethane is the most cost-effective option. As with ammonia and urea, this is largely due to the need for external renewable carbon in the hydrogen route whereas biomethane already contains biogenic carbon.

Demand for biomethane in methanol production could be **0.2 bcm** in 2030, growing to **0.4 bcm** in 2040 and **0.5 bcm** by 2050.

Steel

Steel is a strategic material for the European economy, used extensively in construction automotive and other manufacturing. Europe produced around 126 Mt of crude steel in 2025, of which approximately 54% was primary steel. This study focuses on primary steel, which is currently produced from iron ore using coal as the main energy source, with significant CO₂ emissions.

Achieving climate-neutral primary steel production requires major changes in the production process. Direct Reduction of Iron (DRI) is widely seen as the main pathway for replacing today's coal-based primary steel production. The DRI production route can use gases instead of coal to produce iron and can be combined with electric steelmaking. Both biomethane and green hydrogen can play a role in this route. Unlike in most other sectors in this study, biomethane would therefore not replace existing natural gas use but could create new demand by helping replace coal. This also helps to improve ambient air quality.

Biomethane-based DRI can build on commercially proven natural-gas-based DRI technology and appears attractive compared to alternative climate-neutral production routes in the near term.



Biomethane and hydrogen can replace coal in the production of primary steel.

Towards 2050, biomethane- and hydrogen-based DRI become increasingly comparable in the assessment, indicating that both could play a meaningful and complementary role in the transition of European primary steel production. The pace at which this potential emerges will depend strongly on when European steel plants make the major investments required to transition to DRI. Based on the timelines of plans currently in place, demand for biomethane primary steel production by 2030 is likely to be limited. Based on the analysis this picture can change considerably towards 2040 and 2050, as more European steel plants are expected to transition to the DRI production route. Biomethane could then play a meaningful role alongside green hydrogen (if the assumed very large hydrogen cost reductions materialise). The uptake of biomethane in primary steel production is thought to start during the 2030s, with a potential demand of **6 bcm** by 2040 and almost **7 bcm** by 2050.

Aluminium

Primary aluminium production consists of two main steps: alumina refining and aluminium smelting. In the refining step, bauxite is converted into alumina (Al₂O₃) using the Bayer process, while smelting converts alumina into primary aluminium using electricity-intensive electrolysis. The latter process is electrified, and biomethane will not play a role. This study therefore focuses on the refining step, in which natural gas is currently used to generate the steam and high-temperature heat required for the Bayer process. The sector currently uses about 2.5 bcm of natural gas.

Biomethane can be used to replace natural gas for process energy. An alternative can be the use of renewable electricity in electric boilers or electric calciners. This route can substantially reduce emissions but requires significant modifications to refining assets. Mainly because of this, biomethane is ultimately the more cost-competitive abatement route. Still, it is assumed that some production facilities will shift to electrification. Potential demand for biomethane can be **0.6 bcm** by 2030, growing to **0.9 bcm** by 2040 and **1.1 bcm** by 2050.

Flat glass

The production of flat glass (primarily windows) takes place in large continuous melting furnaces that operate at very high temperatures (up to 1,600°C) and are designed to run continuously for many years. Furnace reliability is crucial. Natural gas currently used in furnaces, is around 1.5 bcm annually.

To mitigate greenhouse gas emissions, biomethane can replace natural gas in the existing flat glass production process, using existing furnace infrastructure while offering reliable operations. Electrification offers an alternative abatement route.

For modelling purposes, this study assumes that an electrified production route becomes a viable abatement option by 2050. Future deployment is expected to involve hybrid furnace configurations rather than fully electric operation, however this additional level of complexity was not considered for the modelling approach.

Under the assumptions applied in this study, electrification is more cost-effective than biomethane. However, as some production installations are located outside of industrial clusters it remains uncertain whether the potentially significant required reinforcement of electricity grids to enable electrification of these large installations will materialize, a sizable part of the installations could still opt for biomethane, also due to its high operational reliability. Biomethane demand in the sector may be **0.4 bcm** in 2030, increasing to **0.6 bcm** by 2040 and **0.8 bcm** by 2050.

Container glass

The production of container glass (bottles) takes place in large continuous melting furnaces that (as with flat glass) operate at temperatures of around 1,500°C and are designed to run continuously for many years.

Furnaces across the EU currently are fired with about 2.6 bcm of natural gas annually, to provide the heat required for glass melting. Furnace conditions directly affect product strength, colour consistency and defect rates, which means that furnaces operate under high operational quality conditions. Biomethane can deliver this quality in existing processes.

Biomethane and electrification are two potential pathways towards climate-neutral container glass production. Both solutions by 2050 have similar costs under the assumptions used in this study, electricity scoring marginally better than biomethane. However, as with flat glass, the electric furnaces not yet fully commercially available today and, yet over time they will become an available option. Electric furnaces have a very high electricity demand, and their feasibility can in more remote locations outside of industrial clusters remain hampered by the lack of sufficient capacities of electricity transmission infrastructure.

This leads to a picture in which biomethane demand in the sector could be **0.6 bcm** in 2030, growing to **1 bcm** by 2040 and almost **1.5 bcm** by 2050.



Furnaces producing glass operate under high operational quality conditions. Biomethane can deliver this quality.

Paper

The production of pulp and paper takes place in large facilities often in remote locations close to forests far away from industrial clusters. Integrated pulp and paper mills have large volumes of biomass waste that is used as process energy, with only a limited need for externally sourced energy. Some paper mills have no on-site pulp production. These so-called non-integrated mills have more limited own biomass residues and therefore a higher need for external energy. These mills generally use natural gas to produce steam used for paper drying process at relatively modest temperatures. The pulp and paper sector as a whole uses some 8 bcm of natural gas annually, a large part of that in non-integrated paper mills.

Natural gas used in paper production can be replaced by biomethane. Alternatively, electric boilers can replace natural gas boilers for steam generation and paper drying using electricity, while retaining the existing drying process. Today, some paper mills successfully use electric boilers alongside natural gas boilers in a hybrid set-up. Industrial heat pumps can otherwise be deployed, which use their input energy in a highly efficient manner. From a cost-competitiveness perspective, industrial heat pumps perform best, followed by electric boilers and biomethane. However, as electrification requires large volumes of renewable electricity in remote areas, electricity transmission infrastructure may not have the required capacities everywhere and for some paper mills biomethane may be the best available option. A combined hybrid use of biomethane and electricity can in many locations also be a solution. The potential biomethane demand can be **0.6 bcm** in 2030, increasing to **2 bcm** by 2040 and around **2.5 bcm** by 2050.

Ceramics

Ceramics production is a diverse sector that produces tiles, bricks, toilets and a range of other products, each with their own production processes. Yet most ceramic products require high-temperature kiln firing (1,000 – 1,200°C) to achieve the desired strength and durability. In this study the focus on kiln firing, as it represents the largest source of natural gas consumption in ceramic production. Currently about 5.3 bcm of natural gas is consumed by the sector annually. This natural gas can be replaced by biomethane to mitigate greenhouse gas emissions, or alternatively by electric kilns. While the use of biomethane does not need modifications in existing production processes and energy assets and infrastructure, electrification often requires the development of a new production asset rather than a simple replacement of the kiln alone, resulting in significantly higher capital investment. On the other hand, the electricity route has a higher energy efficiency. As a result, by 2050 biomethane is slightly more cost-effective than electrification under the assumptions applied in this study. Both abatement options can be expected to be deployed in the sector. This could lead to a demand for biomethane of **0.8 bcm** in 2030, growing to around **1.5 bcm** by 2040 and **~2 bcm** by 2050.

Low temperature heat

Almost 40% of all industrial process heat used in EU industry is low temperature heat, defined as up to 200 degrees Celsius. Currently about 180 TWh or about 17 bcm of natural gas is used to produce low temperature heat as steam or hot water across industrial processes in addition to the ones explicitly analysed in this study and described in the sections above.

During the energy transition, this natural gas can be replaced by biomethane used in existing gas boilers or by electricity used in industrial heat pumps.

Biomethane has meaningful potential for the generation of low- and medium-temperature heat for other applications. While e-boilers may well be attractive, the pace of their deployment will be restricted by the availability of sufficient electricity transmission capacities.

For low-temperature heat, much more efficient heat pumps can be an attractive alternative for e-boilers.

Heat pumps are a very efficient way to produce heat, with the ability to produce 4 kWh per kWh of electricity input (COP or coefficient of performance of 4). This efficiency stems from the fact that a heat pump retrieves heat from other sources (ambient air, ground or water, but in industry mostly from residual heat / waste heat streams in the industrial process), using electricity not to produce heat but to power the compressor and pump. A heat pump thereby technically does not produce heat but displaces it at a very high efficiency. This high efficiency makes it in principle the most cost-efficient option to produce low temperature heat.

However, their deployment is not always practical. Some industrial processes use large quantities of residual heat in other process units through heat recovery and process integration and sufficient residual heat is not always available at practical places. Furthermore, the residual heat is not always available at temperature levels sufficiently close to the temperature required for the heat to be generated, which would lead to a lower COP.

Box 3. Low-temperature heat in the sugar industry

The sugar industry uses low temperature process heat that could be electrified. Yet the sector has the feature that plants typically only run during 3 - 4.5 months per year. Also, residual heat is re-used in other process steps, e.g. steam from sugar juice evaporation is re-used in subsequent steps that require lower temperature process heat. This makes investments in otherwise highly efficient industrial heat pumps relatively expensive and biogas or biomethane can be a good fit, also because sugar factories can produce biogas from their own biomass residues (beet tops and tails).

This means that although electric boilers or heat pumps can have lower overall costs, there can be cases in which e-boilers or gas-boilers are more feasible. Biomethane's exact potential to generate low-temperature heat needs to be established in more detail.

Under the assumptions of this study, there could be a possible demand for biomethane to produce low temperature heat of about **1.5 bcm** in 2030, growing to **5 bcm** by 2040 and **6.5 bcm** by 2050.



Heat pumps are highly (cost) efficient in producing low temperature heat but their deployment is not always practical

Medium temperature heat

Process heat between 200 and 500 degrees Celsius is referred to as medium temperature heat. Outside of the industrial processes that are explicitly analysed in this study, EU industries currently use 53 TWh (5 bcm) of natural gas to produce medium temperature heat, typically supplied through natural gas-fired furnaces, ovens, or boilers.

As with low temperature heat, biomethane can replace natural gas or alternatively electrification is possible. In this category of heat, using electric boilers is more likely than heat pumps due to higher required temperatures. Electric boilers largely miss the high efficiency of heat pumps and are only slightly more efficient than gas boilers. This leads to the insight that electrification is overall still more cost-competitive than biomethane under the assumptions used in this study, however the difference is less pronounced than with low temperature heat. This leads to a potential demand for biomethane of **0.4 bcm** in 2030, increasing to **~1 bcm** by 2040 and about **1.5 bcm** by 2050.

High temperature heat

The supply of process heat of temperatures above 500 degrees Celsius in industrial processes beyond the ones explicitly analysed in this study currently requires 252 TWh or 24 bcm of natural gas in furnaces, kilns and ovens. This energy is used in industrial processes such as chemical crackers and cement production.

Greenhouse gas emissions from this process can be abated by using biomethane, yet energy transition plans for this category often heavily rely on the use of renewable or low carbon hydrogen. While biomethane can be used without modifications in installations, the use of hydrogen requires burner modifications. By 2050, electric ovens are the most cost-competitive solution, followed by biomethane and hydrogen. This leads to a potential biomethane demand of **3 bcm** in 2030, growing to **8 bcm** by 2040 and **9 bcm** by 2050.

Uncertainties and limitations to this study with suggestions

As described in the Introduction, this study is an initial study resulting in a first view on the potential role of biomethane in industry. Further analysis can help to sharpen the picture. Below, a number of uncertainties and limitations to this study are outlined, each with a suggestion for further research to shed more light on the future role of biomethane in industry.

In the current study for many of the industrial processes one or in some cases two alternative abatement options are modeled. It would be valuable to model **additional alternative abatement options** for the analysed industrial processes, to sketch a full breakdown of energy demand across energy carriers (e.g. biomethane, electrification and H₂ for every application).

Also, this study specifically focuses on primary industrial sectors that produce intermediate products (e.g. steel from iron ore), it could be valuable to also assess the future energy mix and the potential role for biomethane in **secondary industries that produce final products** (e.g. cars, ships and wind turbines from steel).

Thirdly, some EU industrial sectors struggle to maintain international competitiveness, raising questions on the future of industrial manufacturing within the EU. On the other hand, **demand for industrial products** may increase due to economic growth. This study assumes future energy consumption in selected industrial processes to remain flat. It could however be valuable to evaluate the **impact of industrial production growth or decline** on future biomethane demand.

Connected to the previous point, the prospect of future **energy efficiency gains** have not been assumed in this study and could be further explored for the specific industrial processes.

This study uses relatively modest electricity prices (€55/MWh in 2030, increasing to €60/MWh in 2040 and reducing to €45/MWh in 2050). Also, biomethane prices (€89, €94 and €88 per MWh in 2030/40/50) are lower than today's price levels. Unsurprisingly, changes to these prices can significantly impact the study results. Furthermore, **analysing the sensitivities to assumed future prices** for electricity, hydrogen, biomethane, CO₂ and their infrastructures to the study results could be helpful to test the robustness of the study conclusions.

Electrification can in many industrial processes have lower total cost of ownership compared to biomethane. Still, biomethane has a role to play especially in processes where residual heat is used in subsequent processes and in remote industrial facilities far removed from industrial clusters, with limited ability to improve grid capacity. It could be valuable to further analyse these **current limitations to electrifications** to see how relevant they still are by 2050 and further explore

the role of **hybrid solutions** that combine electricity and biomethane. That could for example be valuable in the pulp and paper sector.

Finally, it could be useful to **engage more with industrial sectors** and specific companies to deepen the analysis and validate study results.

Sensitivity on cost of carbon

In this study it is assumed that by 2030 a share of around 23% of industrial production in the assessed sectors has achieved climate-neutrality, growing to 74% by 2040 and full climate neutrality well before 2050 (presented as '2050' in this study). This reduction is in line with the proposed revision of the EU ETS as proposed by the European Commission on 17 July 2026.

As a sensitivity, the results of the analysis have been tested under the assumption that an emission reduction of 95% would be achieved by 2040. Such scenario would lead to a higher biomethane demand of 37 bcm instead of 29 bcm. Remarkably, this is an even higher volume than the 35 bcm in 2050, with assumed full climate-neutrality. This spike in biomethane in 2040 can be explained by the notion that gas infrastructure to supply industry with biomethane is already in place while required reinforcements in electricity transmission are assumed not to be fully finalised by 2040. This leads to increasing electrification during the 2040s at the expense of some demand for biomethane in sectors where electrification ultimately has lower total costs of ownership such as paper production.

Chapter 4

Factsheets on industrial processes



Explanation of visuals and indicators used in the industry factsheets

A. Reading guidance on qualitative scoring of competitiveness metrics

2030 score
 2030 → 2050 score change

Indicator	Key findings per route				
Technology readiness	Biomethane route	Low			High
	Alternative route 1				
	Alternative route 2				
Etc.	Etc.				

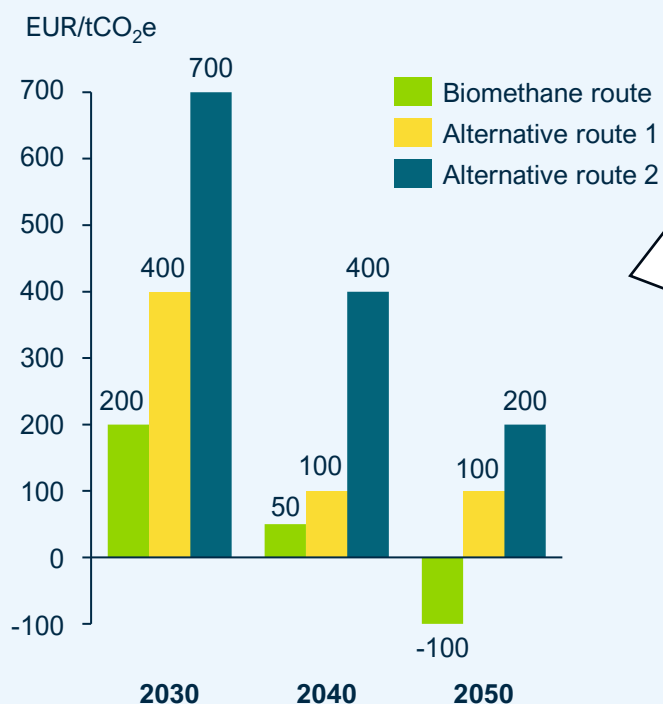
How to read the table?

- Each indicator is scored on a qualitative scale, ranging from Low (left) to High (right).
- The **dark green** bar shows the route's score in 2030.
- The **light green** extension shows the expected change by 2050.
- Longer bars indicate a stronger performance against the indicator.

Example interpretation:

- Biomethane route already scores 'High' in 2030 and remains at that level in 2050.
- Alternative route 1 scores 'Medium' in 2030 and improves by 2050.
- Alternative route 2 scores 'Medium' in 2030 and improves further to the maximum score by 2050.

B. Guidance on how to interpret marginal abatement cost graphs



How to read the graph

- The graph compares the cost competitiveness of decarbonization routes *relative to the reference (natural gas) route* in 2030, 2040 and 2050.
- Values represent the marginal cost difference versus the reference route (EUR/tCO₂e abated). The comparison includes:
 - Energy-related operating costs (e.g., fuel and electricity)
 - Annualized CAPEX for required equipment investments
 - CO₂ costs based on the assumed carbon price trajectory
- Positive values indicate the route is *more expensive* than the reference route.
- Negative values indicate the route is *cheaper* than the reference route.
- Larger absolute values indicate a greater cost difference from the reference route.

Industry factsheet

Ammonia production (1 out of 2)

Sector description

Ammonia is a key chemical feedstock used primarily in fertiliser production and a range of downstream chemical products such as cooling agent in industrial-scale refrigeration systems and used to reduce NO_x emissions in diesel engines and power plants. Europe is a major producer of ammonia, supplying both agricultural and industrial value chains.

Ammonia production is among the most energy- and carbon-intensive processes in the chemical industry. Today, production in Europe mostly relies on the Steam Methane Reforming (SMR) process, which relies predominantly on natural gas as both feedstock and energy source, resulting in significant direct CO₂ emissions. As ammonia is an important intermediate product, mitigating emissions of ammonia production also lowers the carbon footprint of downstream products. Carbon neutrality therefore extends beyond the ammonia plant itself and supports emissions reductions across broader chemical and fertiliser value chains.

Biomethane and renewable hydrogen are key pathways towards climate-neutral ammonia production, enabling the replacement of fossil natural gas while maintaining ammonia's role as an essential industrial feedstock.

European ammonia production in 2025:

~ 12 Mt
NH₃ produced¹

~ 6 bcm
natural gas consumption
by sector

Routes to climate-neutrality

Four production routes are assessed in this study.

- 1. Natural gas-SMR route² (reference):** Natural gas is used as feedstock and fuel. Hydrogen is produced through steam methane reforming (SMR) and converted into ammonia via the Haber-Bosch process. This mature route remains the dominant technology in Europe but generates significant fossil CO₂ emissions.
- 2. Biomethane-SMR route:** Biomethane replaces natural gas in the SMR process while retaining the existing Haber-Bosch synthesis route. This allows most existing infrastructure to be maintained while significantly reducing fossil emissions. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. Blue ammonia route:** Natural gas remains the feedstock for SMR, while CO₂ emissions from hydrogen production are captured and permanently stored. This route substantially reduces emissions³ while retaining the conventional production process.
- 4. Green ammonia route:** Renewable hydrogen produced through electrolysis replaces SMR-derived hydrogen as feedstock⁴. The hydrogen is subsequently converted into ammonia via the Haber-Bosch process. This route enables near-zero-emission ammonia production but requires large volumes of renewable electricity.

Key assumptions in analysis

Emission intensity⁶, tCO₂e / t NH₃

Fuel & feedstock intensity⁶, GJ / t NH₃

Investment⁶ (CAPEX for new installations)

Technology lifetime⁶

Reference route
(natural gas SMR)

1.8

32.1

N/A

25 years

Biomethane SMR

0

32.1

N/A

25 years

Blue ammonia

0.27

32.1

395 EUR / t NH₃⁵

25 years

Green ammonia

0

H₂: 178 kg / t NH₃

N/A

25 years

Notes

¹ Including ammonia used for urea production.

² Other routes exist such as Autothermal Reforming (ATR), but in Europe traditionally SMR routes dominate production landscape.

³ Assuming a ~85% capture rate of CO₂.

⁴ Study assumes that green hydrogen is sourced externally (from global market) and not produced locally on- or near-site.

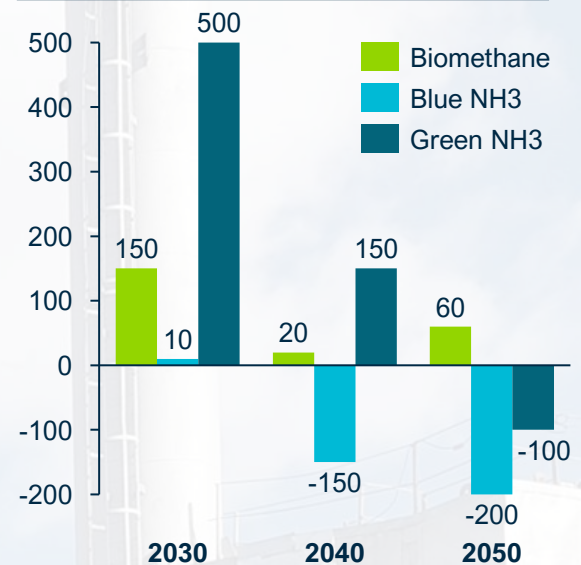
⁵ Existing SMR + CCS retrofit (assuming near-complete capture capability of 85%)

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings per route				
Technology readiness	Biomethane	Low			High
	Blue NH ₃				
	Green NH ₃				
	All routes have high technical feasibility as of 2030 onwards.				
Infra-structure availability	Biomethane				
	Blue NH ₃			→	
	Green NH ₃			→	
	Blue and green ammonia pathways are constrained by limited transport & storage infrastructure in 2030. While availability is expected to improve by 2050, yet unclear whether all ammonia production locations will be connected.				
Asset cycle	Biomethane				
	Blue NH ₃				→
	Green NH ₃				→
	Blue NH ₃ requires ammonia plants to be retrofitted with a CCS installation, and the green NH ₃ requires a significant retrofit to enable production.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Blue ammonia is expected to be the most cost-competitive carbon neutral pathway from 2040 onwards, outperforming both conventional natural gas SMR and alternative low-carbon routes. By 2050, biomethane-based and green ammonia pathways also become more cost-competitive than fossil-based production; however, blue ammonia is expected to retain the strongest economic advantage.

Main findings on biomethane demand potentials

1. Biomethane likely leads ammonia carbon neutrality until early 2030s. While blue ammonia is cheaper, limited CO₂ transport and storage infrastructure is expected to slow deployment, making biomethane the main near-term route towards carbon neutrality.
2. Blue ammonia grows after 2030. As CO₂ and hydrogen infrastructure expands, its cost advantage is expected to drive wider adoption.
3. Biomethane remains relevant in 2050. Blue ammonia may become the dominant low-carbon route, but biomethane is likely to remain the second-largest pathway. Biomethane combined with pre-combustion CCS⁷ (BECCS) could further improve its attractiveness.

Year	Estimated biomethane demand potential ⁸ (bcm)
2030	1.5
2040	2.0
2050	2.0

Notes

⁶ Ammonia Technology Roadmap (IEA, 2023)

⁷ When upgrading biogas into biomethane, CO₂ is liquefied to increase the purity. If the captured CO₂ is permanently stored, the biomethane carries 'negative' emissions.

⁸ Demand potential does not include demand generated by urea production (which requires ammonia as an input). Refer to the factsheet on urea for demand potentials on urea.

Industry factsheet

Ammonia + urea production (1 out of 2)

Sector description

Urea is one of the world's most widely used nitrogen fertilisers and is produced from ammonia and CO₂. Europe is a significant producer of urea, supporting both agricultural demand and broader industrial value chains.

Urea production is closely linked to ammonia production and therefore shares many of the same carbon neutrality challenges. Today, most urea is produced from fossil-based ammonia derived from natural gas. As urea is a major fertiliser product, bringing its production to carbon neutrality can significantly reduce emissions across agricultural value chains. The carbon footprint of urea therefore depends largely on the carbon neutrality of the ammonia used in its production. In addition, urea production requires CO₂ as a feedstock, creating a need for sustainable CO₂ sources as conventional fossil-based ammonia production is phased out.

Biomethane, renewable hydrogen, and low-carbon ammonia pathways are key enablers of climate-neutral urea production. By replacing fossil natural gas in ammonia production, these pathways can substantially lower the emissions intensity of urea while maintaining its critical role in global food production.

European urea production in 2025:

~ 6.5 Mt **~ 3 bcm**
urea produced natural gas consumption by sector

Routes to climate-neutrality

Four production routes are assessed in this study².

- 1. Natural gas-SMR route (reference):** Natural gas is used to produce hydrogen through steam methane reforming (SMR). Ammonia is subsequently synthesised via the Haber-Bosch process and converted into urea using captured process CO₂. This mature route is currently the dominant production pathway in Europe.
- 2. Biomethane-SMR route:** Biomethane replaces natural gas in the SMR process while retaining the existing ammonia and urea production route, making the CO₂ used in the Haber-Bosch of biogenic origin as well. This allows existing infrastructure to be maintained while significantly reducing fossil emissions. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. Blue ammonia & urea route:** Natural gas remains the feedstock for SMR, while CO₂ emissions from hydrogen production are captured and stored. As less process CO₂ remains available¹ for urea synthesis, an additional external CO₂ source is required². This route substantially reduces emissions while retaining the conventional production process to a large extent.
- 4. Green ammonia & urea route:** Green hydrogen produced through electrolysis replaces SMR-derived hydrogen. Since no process CO₂ is generated, urea production requires an external or biogenic CO₂ source^{3,4}. This route enables near-zero-emission ammonia and urea production but requires large volumes of renewable electricity.

Key assumptions in analysis

	Reference route (natural gas SMR)	Biomethane SMR	Blue ammonia	Green ammonia
Emission intensity ⁴ , tCO ₂ e / t urea	1.04	0	0.16	0
Fuel & feedstock intensity ⁴ , MWh / t urea	4.4	4.4	4.4	H ₂ : 3.44
Investment ⁵ (CAPEX for new installations)	N/A	N/A	230 EUR / t urea	N/A
Technology lifetime	25 years	25 years	25 years	25 years

Notes

¹ Assuming a ~90% capture rate of CO₂.

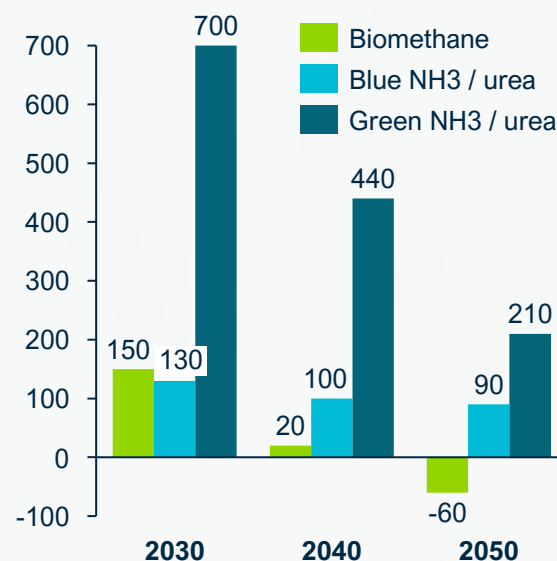
³ For the blue and green routes, biogenic CO₂ is assumed as the feedstock for urea production. This ensures consistency with the biomethane-SMR route and results in lower-emission urea across the value chain. If fossil CO₂ were used instead, downstream urea application would still release fossil carbon, significantly reducing the overall GHG benefit compared to the conventional route.

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings per route				
Technology readiness	Biomethane	Low			High
	Blue NH ₃				
	Green NH ₃				
	All routes have high technical feasibility as of 2030 onwards.				
Infra-structure availability	Biomethane				
	Blue NH ₃			→	
	Green NH ₃			→	
	Blue and green ammonia pathways are constrained by limited infrastructure in 2030. While availability is expected to improve by 2050, yet uncertain whether all ammonia production locations will be connected.				
Asset cycle	Biomethane				
	Blue NH ₃				→
	Green NH ₃				→
	Urea produced using blue- and green NH ₃ require significant asset upgrades / retrofits.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Urea production changes the competitiveness landscape (compared to ammonia production), as low-carbon CO₂ is required as a feedstock alongside ammonia. As a result, blue ammonia is no longer the lowest-cost carbon neutral route. Biomethane becomes highly competitive by 2050, outperforming both alternative low-carbon pathways and the fossil reference route.

Main findings on biomethane demand potentials

1. Demand remains limited before 2030, as the assumed carbon price does not offset the cost increases for the urea production routes.
2. Demand likely accelerates after 2030. Higher assumed carbon costs improve biomethane competitiveness.
3. Biomethane remains attractive in the long term. Green hydrogen-based urea is unlikely to scale widely due to its dependence on both low-carbon H₂ and CO₂, reinforcing biomethane's role in ammonia and urea carbon neutrality.

Year	Estimated biomethane demand potential (bcm)
2030	0.5
2040	1
2050	1.5

Notes

⁴ Ammonia Technology Roadmap (IEA, 2023).

⁵ Study assumes that green hydrogen is sourced externally (from global market), and not produced locally on- or near-site.

Industry factsheet

Methanol production (1 out of 2)

Sector description

Methanol is an important chemical building block used in the production of plastics, adhesives, paints, solvents and synthetic fuels. As a versatile intermediate product, methanol plays a key role in a wide range of industrial value chains.

Europe is a major consumer of methanol, but domestic production has declined in recent years, increasing dependence on imports from other regions. As a result, the carbon footprint of methanol consumed in Europe increasingly depends on production pathways outside Europe.

Conventional methanol production is energy- and carbon-intensive and relies predominantly on natural gas as feedstock and energy source. As methanol is used as an intermediate chemical and (maritime) fuel, reducing emissions in methanol production can lower emissions across a broad range of downstream products and applications. Furthermore, methanol is expected to play an increasingly important role in Europe's future energy system, reinforcing the need for sustainable methanol production. Biomethane, low-carbon hydrogen and captured CO₂ offer pathways towards climate-neutral methanol production while maintaining methanol's role as an essential industrial feedstock.

European methanol sector in 2025:

~ 1.2 Mt	~ 1.2 bcm
CH ₃ OH produced	natural gas consumption by sector

Routes to climate-neutrality

Four production routes are assessed in this study.

- 1. Natural gas route** (reference): Natural gas is converted into synthesis gas (hydrogen and carbon monoxide), which is subsequently converted into methanol. This mature route is currently widely deployed but generates significant fossil CO₂ emissions.
- 2. Biomethane route:** Biomethane replaces natural gas as feedstock while retaining the conventional methanol production route. This allows most existing infrastructure to be maintained while significantly reducing fossil emissions. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. E-methanol route:** Green hydrogen produced through electrolysis is combined with captured biogenic CO₂ (which is assumed to be externally sourced) to produce methanol. This route enables near-zero-emission methanol production but requires large volumes of renewable electricity and access biogenic² CO₂.

Note: More routes to produce methanol sustainably exist, such as gasification of biomass, methanotrophic bioconversion or waste to syngas. These have not been considered in this study and require further investigation.

Key assumptions in analysis

	Reference route (natural gas)	Biomethane route	E-methanol
Emission intensity ⁴ , tCO ₂ e / t methanol	0.8	0	0
Fuel & feedstock intensity ⁴ , GJ / t methanol	36.9	36.9	H ₂ : 192 kg / t methanol ³
Investment (CAPEX for new installations)	N/A	N/A	N/A
Technology lifetime	25 years	25 years	25 years

Notes

¹ Assuming a ~85% capture rate of CO₂.

² For the green methanol route, biogenic or low-carbon CO₂ is assumed as feedstock. Using fossil CO₂ would significantly reduce the downstream emissions benefit of the route.

³ Hydrogen was assumed to be externally sourced. The feedstock requirement therefore represents the H₂ consumption per tonne of methanol produced, which is slightly above the stoichiometric requirement (Source: [Hren, 2024](#)).

Industry factsheet

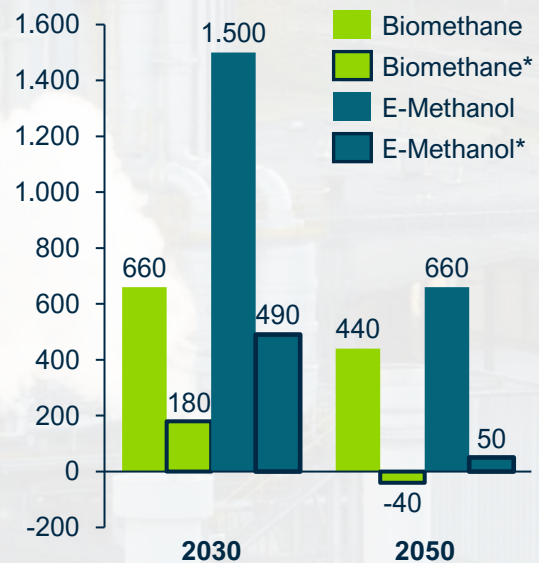
Methanol production (2 out of 2)

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings per route				
Technology readiness	Biomethane	Low			High
	E-methanol				
	Both biomethane-to-methanol and e-methanol pathways have relatively high technology readiness.				
Infra-structure availability	Biomethane				
	E-methanol				
	E-methanol faces significant challenges due to lack of H ₂ -infrastructure in 2030, though significant improvements are expected towards 2050.				
Asset cycle	Biomethane				
	E-methanol				
	Substantial asset modifications or new build capacity are typically required to be able to produce e-methanol, requiring both access to CO ₂ infrastructure (for feedstock supply) and hydrogen infrastructure.				

Abatement cost compared to reference route (EUR / tCO₂e)



*Abatement costs including downstream (gate-to-grave) emissions benefits⁵

Conclusion: Both carbon neutral routes have very high abatement cost. This is mainly driven by the fact that approximately two-thirds to the abatement potential is realized downstream. Including downstream benefits, would lower the abatement cost to 69 EUR / tCO₂e for the biomethane route.

Main findings on biomethane demand potentials

- In Europe, biomethane is expected to deliver over the majority of the methanol sectoral decarbonization towards 2050, driven by lower costs and infrastructure constraints that e-methanol faces in the short- and medium time horizon.
- Biomethane could therefore play an important role in methanol production by 2050. However, the relatively small scale of European methanol production limits overall biomethane demand compared to larger industrial applications.

Year	Estimated biomethane demand potential (bcm)
2030	0.2
2040	0.4
2050	0.5

Notes

⁴ Low carbon energy and feedstock for the European chemical industry (CEFIC, 2017).

⁵ Values excluding downstream emissions consider only emissions reductions during methanol production. Values including downstream emissions additionally account for avoided emissions when renewable methanol displaces fossil methanol at later stages. As (for example) methanol combustion represents a significant share of lifecycle emissions, including downstream effects substantially increases the calculated emissions reduction and lowers the resulting abatement cost.

Industry factsheet

Primary Steel production (1 out of 2)

Sector description

Steel is a strategic material for the European economy, supplying the construction, automotive, machinery and manufacturing sectors. In 2025, Europe produced approximately 126 Mt of crude steel.¹ Around 54% of this production consisted of primary steel, produced from iron ore, while the remaining 46% was secondary steel, produced by recycling steel scrap in electric arc furnaces (EAFs). As secondary steel production is already largely electrified, its further carbon neutrality mainly depends on the availability of climate neutral electricity and steel scrap.

This factsheet focuses on primary steel production, which is one of Europe's most energy- and carbon-intensive industrial processes. The primary steel is predominantly produced in the blast furnace-basic oxygen route, which heavily on coal both as a fuel and as a reducing agent. Decarbonising primary steel therefore requires a fundamental shift in ironmaking. Direct reduced iron (DRI) has been commercially deployed for decades using natural gas and is increasingly being considered in Europe as a pathway towards climate-neutral steel production using either hydrogen or renewable methane.

European primary steel production in 2025:

68 Mt	~2.5 bcm	~350 TWh
primary steel	natural gas consumption by sector ²	Energy input from coal ²

Routes to climate-neutrality

Three production routes are assessed in this study.

1. Coal based BF-BOF route (reference)

The current production route uses coal to reduce iron ore in a blast furnace, followed by steelmaking in a basic oxygen furnace. Coal serves both as the primary energy source and reducing agent, resulting in high direct CO₂ emissions.

2. Biomethane DRI-EAF route

Iron ore is reduced using natural gas in a direct reduction (DRI) shaft furnace and subsequently melted in an electric arc furnace (EAF). In this study, natural gas is assumed to be fully substituted by biomethane, significantly reducing process emissions while relying on commercially proven DRI technology.

3. Hydrogen DRI-EAF route

Hydrogen replaces natural gas as the reducing agent in the DRI process, followed by steelmaking in an EAF. As the steelmaking process does require certain levels of carbon (carburization), this route requires slightly higher levels of carbon input (assumed to be in the form of carbon-neutral biochar in this analysis) in the EAF. This route is widely regarded as the long-term reference technology for near-zero primary steel production but requires large volumes of renewable hydrogen and low-carbon electricity.

Note: More routes to produce steel sustainably exist, such as Natural Gas DRI-EAF, with CCS capability. These have not been considered in this study and require further investigation.

Key assumptions in analysis

	Conventional route (coal based BF-BOF)	Biomethane route (methane based DRI-EAF)	Hydrogen route (H ₂ based DRI-EAF)
Emission intensity	1.9 tCO ₂ / t steel	0 tCO ₂ / t steel	0 tCO ₂ / t steel
Fuel intensity	18.7 GJ / t steel ²	10.5 GJ / t steel ³	8.3 GJ / t steel ³
Investment (CAPEX for new installations)	N/A	730 € / t steel (capacity) ⁴	770 € / t steel (capacity) ⁴
Technology lifetime	40 years	40 years	40 year

Notes

¹ Eurofer (2026). [Steel in Figures 2026](#). Page 16.

² Based on an analysis of the Dutch Environmental Assessment Agency (PBL, 2021, figure 30), which estimates the BF-BOF route to require 1.5 GJ natural gas and 18.7 GJ coal per ton steel produced. With 68 Mt of primary steel production in 2025, this translates to 28 TWh natural gas (or 2.8 bcm) and 350 TWh coal.

³ Agora Industry, Wuppertal Institut & Lund University (2024). [Low-carbon technologies for the global steel transformation](#). Page 54 and 58.

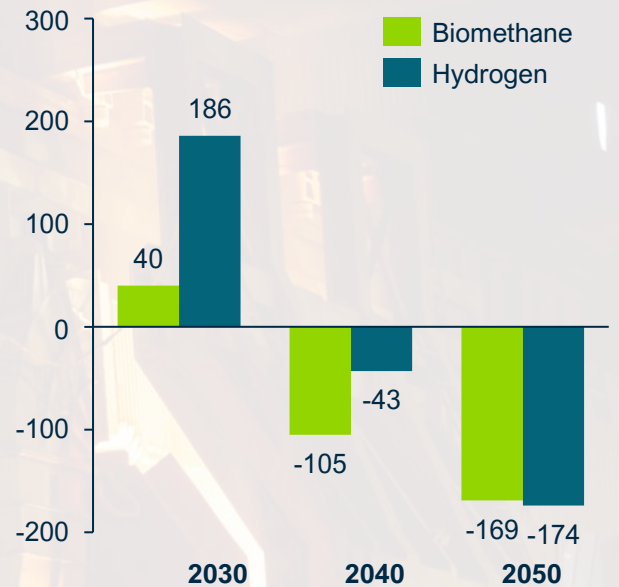
⁴ Using the upper ranges of the annualised specific capital cost in the [Agora Industry \(2024\)](#) study (p. 55 and p. 59), correcting for inflation and assuming 40-year technology lifetime and 10% WACC. For the biomethane route, the cost of the NG-DRI-EAF-CCS were used, subtracting \$10 / t steel as CCS was not included in the analysed route.

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings				
Technology readiness	Biomethane	Low			High
	Hydrogen				
	(Bio)methane-based DRI is used commercially today already, while hydrogen-based DRI is expected to mature further towards 2050.				
Infra-structure availability	Biomethane				
	Hydrogen				
	Gas (methane) infrastructure is already widely available, while access to hydrogen infrastructure is expected to improve towards 2050.				
Asset cycle	Biomethane				
	Hydrogen				
	New European DRI capacity is expected to come online mainly after 2030, enabling greater uptake of both biomethane- and hydrogen-based DRI towards 2050.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Biomethane has lower abatement costs than hydrogen for primary steel production in 2030. The cost difference narrows over time as hydrogen costs decline, with both routes becoming cost-competitive with the conventional production route from 2040 onwards and reaching comparable abatement costs by 2050.

Main findings on biomethane demand potentials

1. Biomethane demand in primary steel is expected to remain limited before 2030,⁵ despite favourable cost competitiveness compared to the hydrogen route. The main constraint is the investment cycle for new DRI capacity, with planned European projects expected to become operational mainly after 2030.
2. Biomethane demand potential increases substantially after 2030 as new DRI capacity comes online. Biomethane can serve as a reducing gas in DRI production, supported by relatively high technology readiness and the availability of existing gas infrastructure. Potential demand reaches around 6 bcm in 2040.
3. Towards 2050, biomethane and hydrogen could both play a meaningful role in primary steel production. Hydrogen becomes increasingly attractive as costs decline and infrastructure develops, while biomethane remains a competitive option. Under the assumptions of this study, potential biomethane demand reaches around 7 bcm in 2050.

Year	Estimated biomethane demand potential
2030	~0 bcm
2040	6.0 bcm
2050	7.0 bcm

⁵ Modelled biomethane demand potential was approximately 3 bcm for 2030,. However, this number was adjusted to 0 bcm in the final results to reflect the current DRI investment cycles. Around 17 Mt of European DRI capacity is targeted for commissioning by 2030 but expected to become operational after 2030 (JRC, 2026, p. 4).

Industry factsheet

Alumina refining (1 out of 2)

Sector description

Primary aluminium production consists of two main steps: alumina refining and aluminium smelting. In the refining step, bauxite is converted into alumina (Al_2O_3) using the Bayer process, while smelting converts alumina into primary aluminium using electricity-intensive electrolysis.

This study focuses on alumina refining because it is the part of the value chain with a substantial demand for high-temperature heat, typically supplied by fossil fuels. By contrast, aluminium smelting is already fully electrified and its carbon neutrality primarily depends on access to low-carbon electricity rather than renewable gas molecules. Biomethane therefore has a much clearer potential role in alumina refining than in smelting.

Alumina refining is energy-intensive and requires large amounts of steam and process heat, typically generated using natural gas, coal or fuel oil. As alumina is the intermediate product used in all primary aluminium production, reducing emissions from refining lowers the carbon footprint of the entire aluminium value chain. Biomethane offers a pathway to bring process heat towards carbon neutrality, while largely retaining existing refining infrastructure.

European alumina production in 2025:

~ 5.7 Mt

alumina

~ 2.5 bcm

natural gas consumption by
sector

Routes to climate-neutrality

Three production routes are assessed in this study.

- 1. Natural gas-fired refining route (reference)**
Natural gas is used to generate the steam and high-temperature heat required for the Bayer process. This mature production route remains widely deployed but results in significant fossil CO_2 emissions.
- 2. Biomethane-fired refining route:**
Biomethane replaces natural gas in boilers and process heaters while retaining the existing refining process. This allows most existing infrastructure to be maintained while significantly reducing fossil emissions. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. Electrified refining route:**
Renewable electricity replaces fossil-fired heat through technologies such as electric boilers or electric calciners. This route can substantially reduce emissions but requires significant modifications to refining assets and large volumes of low-carbon electricity.

Key assumptions in analysis¹

Emission intensity², $\text{tCO}_2\text{e} / \text{t AL}$

Fuel intensity², $\text{GJ} / \text{t AL}$

Electricity intensity², $\text{MWh} / \text{t AL}$

Investment²
(CAPEX for new installations)

Technology lifetime²

Reference route (natural gas refining)

1.19

16.03

0.43

N/A

15 years

Biomethane-fired refining

0.02

16.03

0.43

N/A

15 years

Electrified refining

0.02

0

4.13

208 EUR / t AL³

15 years

Notes

¹ The key assumptions are given in t AL. While figures are expressed in tonnes of aluminium equivalent (t AL) for consistency, the underlying demand refers to alumina consumption. A conversion factor of 1.902 t alumina per tonne of aluminium produced is applied.

² Science-based decarbonisation pathways for the European aluminium industry (European Aluminium, 2023) .

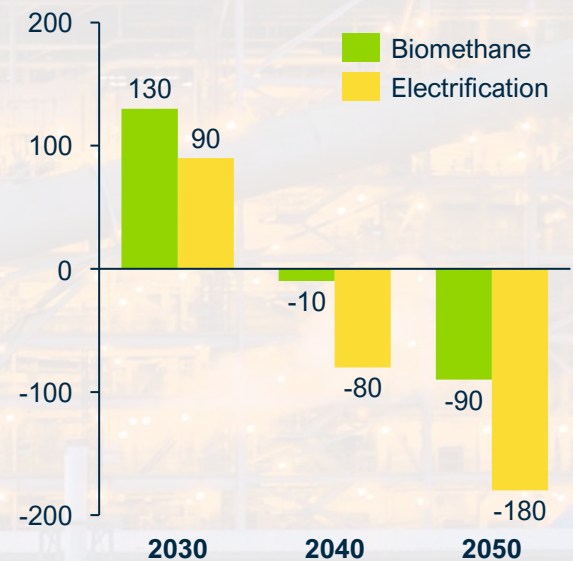
³ The CAPEX numbers include both an electric boiler for digestion and electrical furnace for calcination.

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings				
Technology readiness	Biomethane	Low			High
	Elec.				>
	Biomethane can easily replace natural gas in existing installations, whereas electric refining remains immature but is expected to mature by 2050.				
Infra-structure availability	Biomethane				
	Elec.				>
	Gas infrastructure is widely available at alumina refineries, whereas grid constraints currently limit electrification but are expected to ease by 2050.				
Asset cycle	Biomethane				
	Elec.				>
	The BM route can leverage existing installations, while electrification requires replacement of current assets.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Biomethane and electrification have comparable long-term costs, although electrification becomes more attractive toward 2050. Neither option is cost-competitive in the short term but rising carbon prices make both increasingly competitive with conventional refining.

Main findings on biomethane demand potentials

1. Biomethane is likely to deliver most near-term aluminium decarbonization capacity, as electrification is constrained by grid capacity constraints.
2. Towards 2050, electrification is expected to play an increasingly important role, although technical limitations will likely persist for certain stages of the value chain.
3. While this analysis focuses on alumina refining, stakeholders also identified biomethane opportunities in aluminium recycling, remelting, and downstream processing, suggesting a broader role for biomethane across the aluminium value chain.

Year	Estimated biomethane demand potential (bcm)
2030	0.6
2040	0.9
2050	1

Industry factsheet

Flat glass production (1 out of 2)

Sector description

Flat glass is a key material used in construction, automotive manufacturing and solar energy applications. Production takes place in large continuous melting furnaces that operate at very high temperatures (<1600°C) and are designed to run continuously for many years. As a result, security of energy supply and furnace reliability are critical considerations for the sector.

Flat glass production is energy-intensive and relies predominantly on natural gas-fired furnaces to provide the heat required for melting raw materials. In addition to energy costs and emissions, product quality is a key performance criterion, as small variations in furnace conditions can affect glass quality and increase production losses.

Reducing emissions in flat glass production therefore requires solutions that not only reduce emissions but also maintain continuous operation and consistent product quality. Biomethane and fully electric melting are two potential pathways towards climate-neutral glass production.

European flat glass production in 2025:

8.3 Mt
glass

~ 1.6 bcm
natural gas consumption
by sector

Routes to climate-neutrality

Three production routes are assessed in this study⁵.

- 1. Natural gas furnace (reference):**
Natural gas is combusted in high-temperature melting furnaces to produce flat glass. This mature production route is widely deployed across Europe and provides reliable continuous operation, but results in significant fossil CO₂ emissions.
- 2. Biomethane furnace:**
Biomethane replaces natural gas in the melting furnace while retaining the existing production process and furnace infrastructure. This allows most assets to be maintained while significantly reducing fossil emissions. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible¹.
- 3. Fully electric furnace:**
Electricity replaces combustion as the primary heat source for glass melting. This route can enable near-zero-emission glass production when supplied with low-carbon electricity. However, fully electric flat glass furnaces are not yet commercially available at large scale and are currently limited to pilot and demonstration projects. In addition, maintaining product quality and reliable continuous operation remains an important challenge for large industrial electric flat glass furnaces.

Key assumptions in analysis

Emission intensity², tCO_{2e} / t glass

Fuel intensity², GJ / t glass

Electricity intensity², MWh / t glass

Investment³
(CAPEX for new installations)

Technology lifetime³

Reference route (natural gas furnace)

0.62

7.7

0

N/A

20 years

Biomethane furnace

0.19

7.7

0

N/A

20 years

Electric furnace

0.19

0

1.13⁴

295 EUR / t glass

10 years

Notes

¹ Biomethane-fired furnaces combined with bio-energy carbon capture and storage (BECCS) offer possibilities to offset residual process emissions from production.

² A review of decarbonization options for the glass industry (Zier et al., 2021).

³ Decarbonising the glass industry: A comprehensive techno-economic assessment of low-emission pathways (Salman et al., 2025).

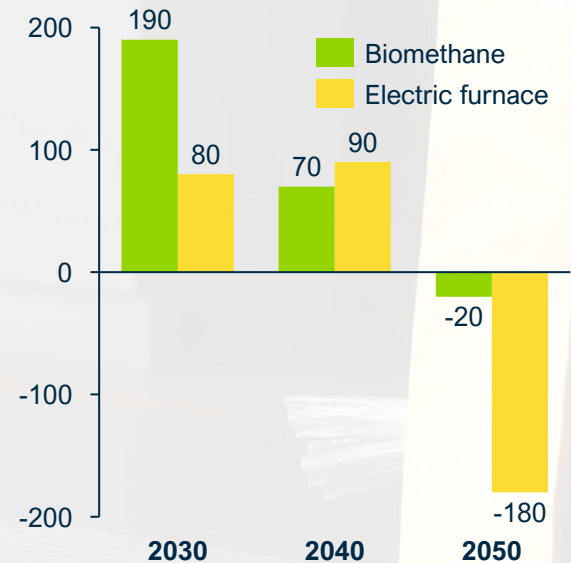
⁴ Efficiency of electric furnace: 85%; efficiency of (modern) gas fired furnace: 45% (Salman et al., 2025).

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings
Technology readiness	Biomethane Low High
	Elec.
	Electrification of flat glass production faces significant technical constraints, with persistent future challenges.
Infra-structure availability	Biomethane
	Elec.
	Gas infrastructure is readily available, whereas electricity infrastructure is not expected to become fully unconstrained due to the substantial grid capacity required for glass production.
Asset cycle	Biomethane
	Elec.
	Short-term asset cycles constrain electrification, but this impact declines over time.

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Electrification is the more cost-competitive pathway for flat glass production, driven by efficiency and the cost difference between biomethane and electricity. By 2050, both electrification and biomethane become cost-competitive with the natural gas reference pathway under the assumed carbon price trajectory.

Main findings on biomethane demand potentials

1. Biomethane uptake in the flat glass sector is expected to accelerate towards 2030, driven by climate-neutrality targets and constrained electrification alternatives due to technological and infrastructure barriers.
2. As technology matures and infrastructure constraints ease, electrification is expected to increase, slowing further growth in biomethane demand.
3. BECCS⁶ could play a role in addressing residual process emissions from carbonate feedstocks that cannot be eliminated through fuel switching alone.

Year	Estimated biomethane demand potential (bcm)
2030	0.4
2040	0.6
2050	0.8

Notes

⁵ In practice, future flat glass decarbonization pathways may include hybrid furnace concepts combining electricity and gaseous fuels. These configurations were not assessed as a separate production route and are assumed to be reflected in the relative deployment of the biomethane and electric furnace pathways.

⁶ Bio-energy carbon capture and storage (BECCS).

Industry factsheet

Container glass production (1 out of 2)

Sector description

Container glass is a key packaging material used for food, beverage, pharmaceutical and cosmetic products. Production takes place in large continuous melting furnaces that operate at temperatures of around 1,500°C and are designed to run continuously for many years. As a result, furnace reliability, product quality and security of energy supply are critical considerations for the sector.

Container glass production is energy-intensive and relies predominantly on natural gas-fired furnaces to provide the heat required for glass melting. In addition to energy costs and emissions, glass quality is a key performance criterion, as furnace conditions directly affect product strength, colour consistency and defect rates.

Carbon neutrality of container glass production therefore requires solutions that reduce emissions while maintaining continuous operation, product quality and operational reliability. Biomethane and electrification are two potential pathways towards climate-neutral container glass production.

European flat glass production in 2025:

20 Mt
glass

~ 2.6 bcm
natural gas consumption
by sector

Routes to climate-neutrality

Three production routes are assessed in this study.

- 1. Natural gas furnace (reference):**
Natural gas is combusted in high-temperature melting furnaces to produce flat glass. This mature production route is widely deployed across Europe and provides reliable continuous operation, but results in significant fossil CO₂ emissions.
- 2. Biomethane furnace:**
Biomethane replaces natural gas in the melting furnace while retaining the existing production process and furnace infrastructure. This allows most assets to be maintained while significantly reducing fossil emissions. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. Fully electric furnace:**
Electricity replaces combustion as the primary heat source for glass melting. This route can enable near-zero-emission glass production when supplied with low-carbon electricity. However, fully electric melting is currently not technically suitable for all container glass products, particularly certain color and specialty glass grades produced in larger furnaces. While electric furnaces are commercially available for selected applications, the technology is not yet fully TRL-ready as a sector-wide solution and remains limited by scale, product flexibility and operational experience.

Key assumptions in analysis

Emission intensity¹, tCO₂e / t glass

Fuel intensity², GJ / t glass

Electricity intensity², MWh / t glass

Investment¹
(CAPEX for new installations)

Technology lifetime³

Reference route (natural gas SMR)

0.4

4.8

0.13

N/A

20 years

Biomethane furnace

0.1

4.8

0.13

N/A

20 years

Electric furnace

0.1

0

0.84

207 EUR / t glass

10 years

Notes

¹ Assessing container glass production decarbonization through amine scrubbing, calcium looping and electrification: a comparative techno-economic analysis (Palone et al., 2026).

² Decarbonisation options for the dutch container and tableware glass industry (MIDDEN, 2019).

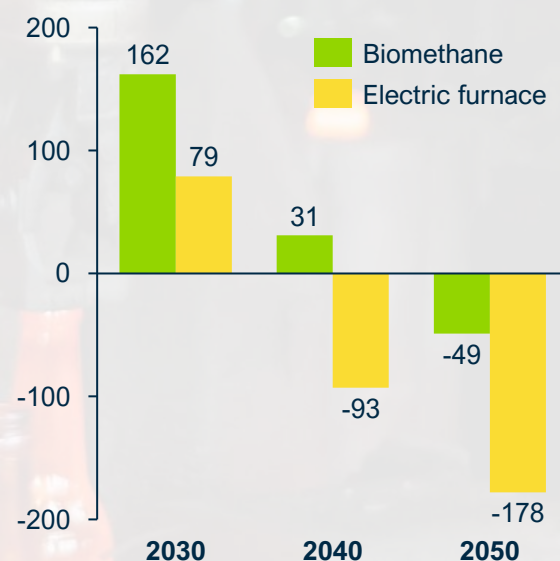
³ Decarbonising the glass industry: A comprehensive techno-economic assessment of low-emission pathways (Salman et al., 2025).

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings				
Technology readiness	Biomethane	Low			High
	Elec.				
	Electrification of container glass production faces significant technical constraints that are expected to persist, whereas biomethane can leverage the existing gas infrastructure.				
Infra-structure availability	Biomethane				
	Elec.				
	Gas infrastructure is readily available, whereas electricity infrastructure is not expected to become fully unconstrained due to the substantial grid capacity required for glass production.				
Asset cycle	Biomethane				
	Elec.				
	Short-term asset replacement cycles constrain electrification, whereas biomethane can be deployed immediately by leveraging existing assets.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Electrification remains the more cost-competitive pathway for container glass production, although the cost difference with biomethane is less pronounced than for flat glass due to the lower energy intensity of the production process. Under the assumed carbon price trajectory, both electrification and biomethane become cost-competitive with the natural gas reference pathway by 2050.

Main findings on biomethane demand potentials

- Similar to flat glass, biomethane uptake in the container glass sector is expected to accelerate towards 2040, driven by the ability to keep using existing assets.
- Electrification is expected to play a major role due to its efficiency advantage (85% over 45%), but technical and product-quality constraints are likely to limit its applicability for certain glass types, resulting in a continued role for biomethane alongside electrification.
- BECCS⁴ may play a role in addressing residual emissions and enabling net-negative emissions in the container glass sector.

Year	Estimated biomethane demand potential (bcm)
2030	0.6
2040	1.0
2050	1.5

Notes

⁴ Bio-energy carbon capture and storage (BECCS).

Industry factsheet

Paper drying at non-integrated mills (1 out of 2)

Sector description

This study focuses on paper drying in non-integrated paper mills¹, as drying accounts for the majority of fossil thermal energy demand within these facilities and represents a relevant application for biomethane.

Non-integrated mills purchase pulp from external suppliers and therefore do not have access to biomass residues generated during the pulping process. As a result, they are more dependent on external energy sources than integrated mills, which can often supply a large share of their heat demand using internally available biomass.

Paper drying accounts for the majority of thermal energy demand in non-integrated mills and is typically supplied by natural gas-fired steam generation. Bringing this heat demand towards carbon neutrality can therefore significantly reduce emissions from paper production while largely retaining existing production assets and product specifications.

Note: In some cases, natural gas-fired boilers are complemented by electric boilers, reducing fossil fuel consumption while generating revenues from demand response and flexibility services. This has not been considered in this foundational study and requires further research.

European paper production at non-integrated mills:

47.4 Mt

paper

~ 8 bcm

natural gas consumption by
sector

Routes to climate-neutrality in 2050²

Three production routes are assessed in this study.

- 1. Natural gas-fired drying (reference):**
Natural gas is used in boilers to generate steam in turbines for paper drying. This mature production route remains widely deployed but results in significant fossil CO₂ emissions.
- 2. Biomethane-fired drying:**
Biomethane replaces natural gas in existing boilers while retaining the current drying process and infrastructure. This allows significant emissions reductions with limited modifications to production assets. A 100% biomethane supply is assumed for this study, although lower biomethane-natural gas blends are also possible.
- 3. Heat pump-based drying:**
Industrial heat pumps provide heat for paper drying using electricity. A heat pump COP⁵ of 2.5 is assumed. This route substantially reduces direct emissions but requires additional electricity supply and integration of heat pump systems. Furthermore, a combination with another boiler (natural gas / e-boiler) or thermal storage facility may be required to start up and stabilize the drying process³.
- 4. Electric boiler-based drying:**
Electric boilers replace natural gas boilers for steam generation and paper drying using electricity, while retaining the existing drying process. This pathway significantly reduces direct emissions but requires significant additional electricity supply and grid capacity. A 100% electric configuration is assumed for this study.

Key assumptions in analysis

Emission intensity⁴, tCO_{2e} / t paper

0.24

Fuel intensity⁵, GJ / t paper

6.3

Electricity intensity⁵, MWh / t paper

0

Investment
(CAPEX for new installations)

N/A

Technology lifetime

15 years

Biomethane-fired drying

0

6.3

0

N/A

15 years

Heat pump-based drying

0

0

0.63⁶

260 EUR / t paper

15 years

E-boiler-based drying

0

0

1.59⁷

39 EUR / t paper

15 years

Notes

¹ Integrated mills produce both pulp and paper, generating biomass residues onsite that are often used to meet a significant share of their thermal energy demand. Non-integrated mills purchase pulp and typically rely more heavily on external fuel sources, such as natural gas, for paper drying and steam generation.

² Hybrid configurations combining these pathways are likely to emerge by 2050. While not explicitly modelled, this expectation is reflected in the conclusions on the following page.

³ Given the low expected run-time of the additional boiler (and minimal cost) this has not been included in the study's assumptions.

⁴ Key statistics (CEPI, 2025).

Industry factsheet

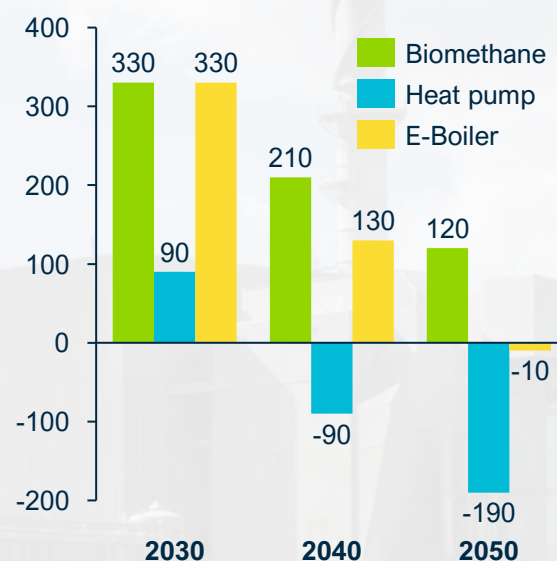
Paper drying at non-integrated mills (2 out of 2)

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings per route				
Technology readiness	Biomethane	Low			High
	Heat pump			→	
	E-boiler				
	Both gas- and electric- boilers and heat pumps are widely available by 2030 and remain so until 3050.				
Infra-structure availability	Biomethane				
	Heat pump			→	
	E-boiler			→	
	Gas infrastructure is widely available and expected to remain so, whereas electricity infrastructure is currently constrained and, given location outside industrial clusters, is unlikely to become fully unconstrained.				
Asset cycle	Biomethane				
	Heat pump				→
	E-boiler				→
	For the biomethane route, existing assets can be utilized. Limited asset turnover is expected by 2030, but the current fleet will largely need replacement by 2050.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Heat pumps offer a clear cost advantage over biomethane and become cost-competitive around 2040. Replacing heat pumps with e-boilers reduces the competitiveness of electrification compared to biomethane. At the assumed energy prices, e-boiler application still outperforms biomethane in 2050.

Main findings on biomethane demand potentials

1. Biomethane offers a pragmatic GHG reduction pathway for non-integrated mills, leveraging existing infrastructure while delivering significant emissions reductions.
2. In the short to medium term, paper producers are likely to adopt hybrid configurations of e-boilers and gas boilers, allowing methane in the form of biomethane or natural gas to provide flexibility during periods of high electricity prices.
3. Heat pump deployment is currently constrained by technical limitations, but as these barriers are expected to diminish, electrification is likely to increase towards 2050, slowing demand for additional biomethane.⁸

Year	Estimated biomethane demand potential (bcm)
2030	0.6
2040	2.0
2050	2.5

⁵ This includes average values provided by CEPI, with appropriate conversions applied for the analysis.

⁶ Coefficient of Performance (COP) of 2.5 was assumed.

⁷ Efficiencies gas-boiler assumed to be 95% and electric boiler 99% (Agora, 2023).

⁸ The heat-pump cost advantage is based on static prices and base-load use; flexible hybrid e-boiler plus biomethane operation may be more cost-effective.

Industry factsheet

Ceramics production (1 out of 2)

Sector description

Ceramics is a highly diverse industrial sector, producing a wide range of products including tiles, bricks, sanitaryware (e.g. toilets and sinks), tableware, technical ceramics, refractories and other specialty products. While production processes vary between subsectors, most ceramic products require high-temperature kiln firing (1000 - 1200°C) to achieve the desired strength, durability and product properties.

In this study the focus on kiln firing, as it represents the largest source of natural gas consumption in ceramic production, although additional energy is also required for upstream process steps such as drying and material preparation. Ceramic kilns operate at high temperatures, and product quality is highly sensitive to firing conditions, making temperature control and process stability important considerations.

Bringing the kiln firing towards carbon neutrality can therefore significantly reduce emissions from total ceramic production. Biomethane and electrification provide alternative pathways to replace fossil natural gas, although the implications for existing assets differ substantially between the two routes.

European ceramics in 2025:

€33 bn

EU production value

~ 5.3 bcm

natural gas consumption
by sector

Routes to climate-neutrality

Three production routes are assessed in this study.

- 1. Natural gas-fired kiln (reference):**
Natural gas is combusted in high-temperature kilns to fire ceramic products. This mature production route remains widely deployed across Europe and provides reliable process control, but results in significant fossil CO₂ emissions.
- 2. Biomethane-fired kiln:**
Biomethane replaces natural gas in the kiln while retaining the existing production process and most furnace infrastructure. This allows significant emissions reductions with limited modifications to existing assets. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. Electric kiln:**
Electricity replaces combustion as the primary heat source for kiln firing. This route can enable near-zero-emission ceramic production when supplied with low-carbon electricity. However, electrification often requires the development of a new production asset rather than a simple replacement of the kiln alone, resulting in significantly higher capital investment requirements compared to the biomethane route.

Key assumptions in analysis

Emission intensity ¹ , tCO ₂ e / t	0.224
Fuel intensity ¹ , GJ / t	3.1
Electricity intensity ¹ , MWh / t	0.19
Investment ² (CAPEX for new installations)	N/A
Technology lifetime ²	20 years

Reference route (natural gas)

Emission intensity ¹ , tCO ₂ e / t	0.224
Fuel intensity ¹ , GJ / t	3.1
Electricity intensity ¹ , MWh / t	0.19
Investment ² (CAPEX for new installations)	N/A
Technology lifetime ²	20 years

Biomethane-fired kiln

Emission intensity ¹ , tCO ₂ e / t	0.048
Fuel intensity ¹ , GJ / t	3.1
Electricity intensity ¹ , MWh / t	0.19
Investment ² (CAPEX for new installations)	N/A
Technology lifetime ²	20 years

Electric kiln

Emission intensity ¹ , tCO ₂ e / t	0.048
Fuel intensity ¹ , GJ / t	0
Electricity intensity ¹ , MWh / t	0.96
Investment ² (CAPEX for new installations)	223 EUR / t
Technology lifetime ²	20 years

Notes

¹ Decarbonisation options for the Dutch ceramic industry (MIDDEN, 2019); averages of several ceramic applications were taken.

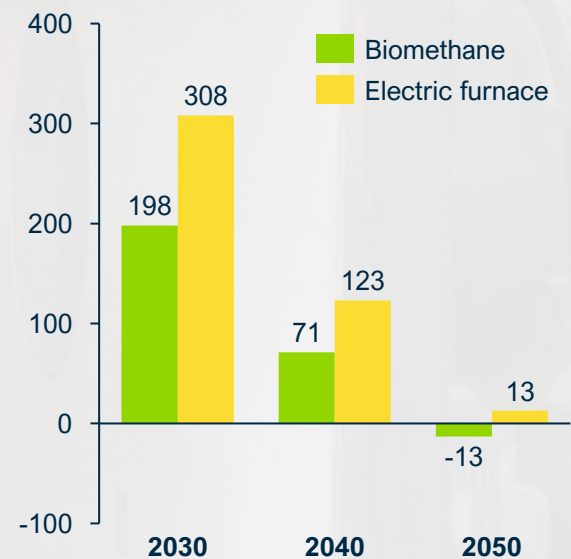
² Industrial Fuel Switching Market Engagement Study (Jacobs, 2018).

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings
Technology readiness	Biomethane Low High
	E-kiln
	Near-term electrification is constrained by technical challenges and sector heterogeneity, whereas methane-fired kilns remain more readily deployable.
Infra-structure availability	Biomethane
	E-kiln
	Gas infrastructure is readily available, whereas electricity infrastructure is not expected to become fully unconstrained due to the substantial grid capacity required for ceramics production.
Asset cycle	Biomethane
	E-kiln
	As the kiln is a core production asset, electrification requires significant investment, while biomethane offers a drop-in replacement.

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Biomethane is the more cost-competitive carbon neutral pathway due to the high CAPEX requirements of electric kilns and expected increases in electricity network costs. However, this cost advantage gradually narrows towards 2050, resulting in similar cost-competitiveness between the two pathways.

Main findings on biomethane demand potentials

- Biomethane is an attractive carbon neutral pathway in both the short and long term, as it can leverage existing assets and infrastructure while maintaining current production processes across the heterogeneous ceramics sector.
- Electrification is expected to play a role in selected applications, but product-specific temperature and quality requirements are likely to limit its applicability, particularly for high-temperature processes and certain ceramic products.
- BECCS³ could enable full carbon neutrality in the ceramics sector by offsetting residual process emissions.

Year	Estimated biomethane demand potential (bcm)
2030	0.8
2040	1.5
2050	2

Notes

³ Bio-energy carbon capture and storage (BECCS).

Industry factsheet

Cross sector: Low temperature heat (1 out of 2)

Sector description

Low-temperature heat applications are found across a wide range of industries, including chemicals, food and beverage, paper, and general manufacturing. This factsheet covers industrial heat demand **below 200°C** in sectors and applications that have not been modelled separately.

Most low-temperature heat is currently supplied by natural gas boilers producing steam or hot water. Compared to high-temperature heat applications, these processes are generally more suitable for electrification.

By 2050, heat pumps are widely considered the leading carbon neutral route for low-temperature heat due to their high efficiency and improved commercial maturity, with technological developments expected to extend their applicability towards 200°C. However, applicability remains site-specific, particularly in the chemicals and pharmaceuticals sectors, where complex heat integration and recovery systems can limit heat pump deployment.

Biomethane remains a carbon neutrality option where electrification is technically difficult or constrained by site-specific process integration.

Overview of residual low-temperature in 2025:

< 200 °C

typical temperature

~ 17 bcm

estimated natural gas demand¹

Routes to climate-neutrality

Three production routes are assessed in this study.

- 1. Natural gas boiler (reference):**
Natural gas is combusted in industrial boilers to generate steam or hot water for low-temperature process heat applications. This mature and widely deployed route results in significant fossil CO₂ emissions.
- 2. Biomethane boiler:**
Biomethane replaces natural gas in existing boiler systems while retaining the current heat generation infrastructure. This allows significant emissions reductions with limited modifications to existing assets. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. Heat pump route:**
Industrial heat pumps use electricity to upgrade low-temperature heat to useful process temperatures. Heat pumps are assumed to be the primary carbon neutral pathway for low-temperature heat applications and can achieve significantly higher efficiencies than combustion-based heat generation. However, deployment may face additional complexity in facilities with strong process heat integration or other process dependencies.

For this study, a typical boiler (or heat pump) thermal capacity of **10 MW** has been assumed.

Key assumptions in analysis

Emission intensity², tCO₂e / MWh heat

Fuel intensity³, MWh [fuel] / MWh heat

Investment³
(CAPEX for new installations)

Technology lifetime³

Reference route (natural gas)

0.21

1.05 MWh NG

N/A

25 years

Biomethane-fired kiln

0

1.05 MWh BM

N/A

25 years

Heat pump

0

0.25 MWh elec (COP = 4)

150 EUR / MWh

20 years

Notes

¹ Calculated as European industrial gas demand (Eurostat) minus the gas demand of sectors covered in preceding factsheets. The remaining demand is allocated to low-, medium-, and high-temperature processes based on insights from the [Danish Technological Institute](#) (figure 1).

² Emissions of natural gas combustion (LHV) (IPCC, 2006).

³ The business case for electrifying industrial heat (Agora, 2023).

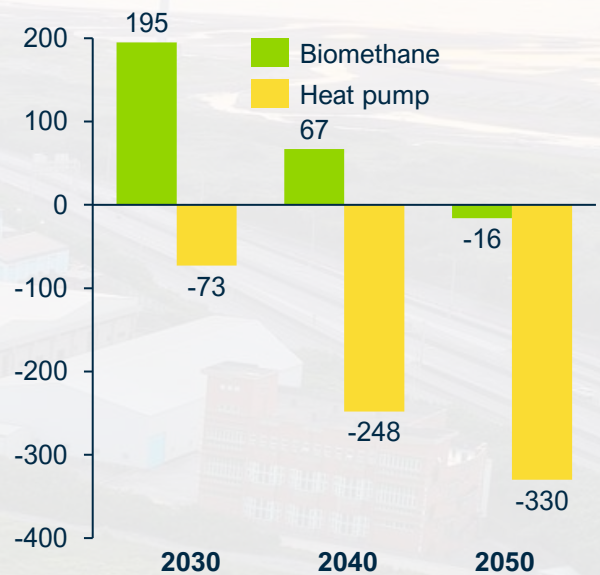
Industry factsheet

Cross sector: Low temperature heat (2 out of 2)

Main results on biomethane competitiveness vs. alternative carbon neutral options

Indicator	Key findings on routes			
	2030 score	2030 → 2050 score change	2050 score	2050 score
Technology readiness	Biomethane	Low		High
	Heat pump			
Industrial heat pumps are a mature and commercially available technology, although some applications remain challenging due to complex process integration requirements.				
Infra-structure availability	Biomethane			
	Heat pump			
Heat pumps require additional grid capacity as they replace natural gas-fired heat generation. While grid constraints are expected to ease over time, they are likely to remain a consideration in some locations through 2050				
Asset cycle	Biomethane			
	Heat pump			
Heat pump deployment typically requires broader process and site integration than a simple boiler replacement. Achieving optimal performance often involves wider asset modifications, heat recovery integration, and process redesign.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Heat pumps are expected to be a highly cost-effective carbon neutral option due to their superior energy efficiency. While deployment typically requires upfront capital investment, these costs are largely offset by lower operating expenses, resulting in negative marginal abatement costs across the 2030-2050 period.

Main findings on biomethane demand potentials

- Despite the strong cost competitiveness of heat pumps for low-temperature process heat, biomethane is expected to retain a role in industrial heat carbon neutrality.
- Biomethane demand will likely be driven by industrial applications where heat pumps are technically challenging to deploy or would require substantial process integration, engineering modifications, and asset retrofits.
- As a result, biomethane demand of approximately 6.4 bcm is still expected by 2050, despite the widespread adoption of heat pumps.

Year	Estimated biomethane demand potential (bcm)
2030	1.5
2040	4.5
2050	6.5

Industry factsheet

Cross sector: Medium temperature heat (1 out of 2)

Sector description

Medium-temperature heat processes **between 200°C and 500°C** are used across a range of industries, including chemicals, food processing, pulp and paper, metals, and general manufacturing. This factsheet covers industrial heat demand in sectors and applications not modelled separately.

Heat is typically supplied through natural gas-fired furnaces, ovens, or boilers. Compared with low-temperature heat, these applications rely more heavily on direct heating and require higher process temperatures.

Direct electrification through electric boilers and furnaces is a key carbon neutral route. These technologies can provide medium-temperature heat efficiently but may require equipment replacement, process redesign, and additional electricity grid capacity. Electric boilers can generate temperatures up to 500°C for chemical processes.

Biomethane provides a lower-carbon alternative where direct electrification is technically challenging, economically unattractive, or constrained by grid availability. It can generally use existing gas-fired equipment.

Overview of residual medium-temperature in 2025:

200 - 500 °C

typical temperature range

~ 5 bcm

estimated natural gas demand¹

Routes to climate-neutrality

Three production routes are assessed in this study.

- 1. Natural gas-fired boiler (reference):** Natural gas is combusted in industrial boilers to generate medium-temperature process heat. This is a mature and widely deployed route but results in significant fossil CO₂ emissions.
- 2. Biomethane-fired furnace or oven:** Biomethane replaces natural gas while retaining the existing combustion-based heating configuration. This can deliver substantial emissions reductions with relatively limited asset modifications. A 100% biomethane blend is assumed, although lower biomethane-natural gas blends are also possible.
- 3. Electric boiler (or furnace):** Electric boilers and furnaces replace combustion-based heat generation with direct electrification. The route avoids on-site combustion emissions and can provide medium-temperature heat with high conversion efficiency.

For this study, a typical boiler thermal capacity of **25 MW** has been assumed.

Key assumptions in analysis

Emission intensity², tCO₂e / MWh heat

Fuel intensity³, MWh [fuel] / MWh heat

Investment³ (CAPEX for new installations)

Technology lifetime³, years

Reference route (natural gas)

0.21

1.05 MWh NG²

N/A

25

Biomethane-fired kiln

0

1.05 MWh BM⁴

N/A

25

E-boiler

0

1.01 MWh electricity⁵

20 EUR / MWh heat

25

Notes

¹ Calculated as European industrial gas demand (Eurostat) minus the gas demand of sectors covered in preceding factsheets. The remaining demand is allocated to low-, medium-, and high-temperature processes based on insights from the [Danish Technological Institute](#) (figure 1).

² Emissions of natural gas combustion (LHV) (IPCC, 2006).

³ The business case for electrifying industrial heat (Agora, 2023).

⁴ Assumed efficiency of natural gas boiler = 95%.

⁵ Assumed efficiency of e-boiler is 99%.

Industry factsheet

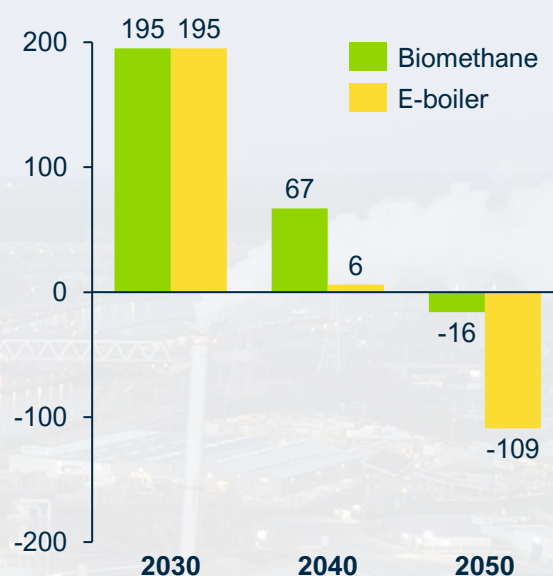
Cross sector: Medium temperature heat (2 out of 2)

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings per route				
Technology readiness	Biomethane	Low			High
	E-boiler				
	Both biomethane (gas) and electric boilers are commercially mature technologies today, with no material technology or deployment barriers expected to change their applicability through 2050.				
Infra-structure availability	Biomethane				
	E-boiler				
	Electric boiler deployment is currently limited by grid connection availability and high power requirements. Although these constraints are expected to ease over time, grid capacity is likely to remain a deployment challenge through 2050				
Asset cycle	Biomethane				
	E-boiler				
	Electric boiler deployment typically requires only limited asset modifications and process integration. Combined with relatively low CAPEX requirements, this supports straightforward implementation.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: Biomethane and electric boilers are broadly cost-competitive in 2030. By 2050, electric boilers are expected to gain a cost advantage as (assumed) declining electricity prices improve the economics of industrial electrification.

Main findings on biomethane demand potentials

1. Biomethane is expected to play a key role in achieving net-zero emissions in medium-temperature heat processes, particularly before 2040 when grid constraints limit large-scale electrification.
2. Electric boilers are cost-competitive compared to biomethane under the electricity price assumption, but higher power prices could materially improve the relative competitiveness of biomethane⁶.
3. Biomethane demand is expected to grow rapidly to ~1 bcm by 2040. Thereafter, improving grid availability and increased competition from electric boilers are expected to slow growth, resulting in demand of ~1.5 bcm by 2050.

Year	Estimated biomethane demand potential (bcm)
2030	0.4
2040	1.0
2050	1.5

Notes

⁶ Contrary to heat pumps (see low temperature factsheet), e-boilers do not have a Coefficient of Performance (COP) that drives significant competitive advantage, the electricity price is the decisive factor on whether e-boilers are competitive over biomethane.

Industry factsheet

Cross sector: High temperature heat (1 out of 2)

Sector description

High-temperature heat processes (**>500°C**) are used across energy-intensive sectors including chemicals, glass, ceramics, cement, metals, and other manufacturing industries. This factsheet covers industrial heat demand in sectors and applications not modelled separately.

These applications typically rely on furnaces, kilns, ovens, and other direct-fired equipment, where high heat requirements and product quality considerations limit carbon neutral options. Compared to low- and medium-temperature heat, high-temperature processes are not suitable for heat pumps and instead require either combustion-based fuels or direct electric heating.

Biomethane offers a drop-in carbon neutral pathway by replacing natural gas in existing furnace systems with limited modifications. Electric furnaces can eliminate on-site combustion emissions but typically require significant asset replacement and additional grid capacity. Hydrogen-fired furnaces provide an additional carbon neutral route for applications requiring high-temperature flame heating. However, widespread adoption depends on the availability of competitively priced low-carbon hydrogen and supporting infrastructure.

Overview of sector in 2025:

> 500 °C

typical temperature range

~ 24 bcm

estimated natural gas demand¹

Routes to climate-neutrality

Three production routes are assessed in this study.

- 1. Natural gas furnace (reference):**
Natural gas is combusted in industrial furnaces, kilns, and ovens to provide high-temperature process heat. This mature route is widely deployed but results in significant fossil CO₂ emissions.
- 2. Biomethane furnace:**
Biomethane replaces natural gas in existing furnace systems, enabling substantial emissions reductions with limited asset modifications. This provides a relatively low-disruption carbon neutral pathway for high-temperature heat.
- 3. Fully electric oven:**
Electric furnaces replace combustion-based heating with direct electrical heating. While this eliminates on-site combustion emissions, deployment typically requires significant asset replacement and additional grid capacity.
- 4. Hydrogen-fired furnace:**
Green hydrogen replaces natural gas as the combustion fuel in industrial furnaces, allowing continued use of flame-based heating while reducing direct emissions. Deployment requires burner modifications, hydrogen infrastructure, and access to affordable low-carbon hydrogen.

Key assumptions in analysis

Emission intensity²,
tCO₂e / MWh heat

Fuel intensity, MWh [fuel],
MWh heat

Investment
(CAPEX for new installations)

Technology lifetime,
years

Reference route (natural gas)

0.29

1.43 MWh NG²

N/A

30

Biomethane-fired furnace

0

1.43 MWh BM

N/A

30

Electric furnace

0

1.18 MWh electricity⁴

60 EUR / MWh

30

Hydrogen furnace

0

1.43 MWh H₂⁵

N/A

30

Notes

¹ Calculated as European industrial gas demand (Eurostat) minus the gas demand of sectors covered in preceding factsheets. The remaining demand is allocated to low-, medium-, and high-temperature processes based on insights from the [Danish Technological Institute](#) (figure 1).

² Emissions of natural gas combustion (LHV) ([IPCC, 2006](#)).

³ The business case for electrifying industrial heat ([Agora, 2023](#)).

⁴ Gas furnace efficiency of 70% assumed. E-furnace efficiency is assumed to be 85%. Efficiencies vary strongly across processes.

⁵ H₂ furnace assumed to have similar efficiency after modifications as a gas furnace: 70%

Industry factsheet

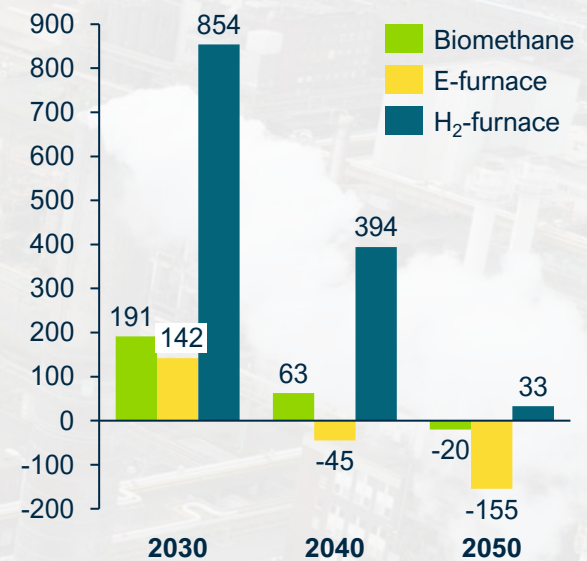
Cross sector: High temperature heat (2 out of 2)

Main results on biomethane competitiveness vs. alternative carbon neutral options

2030 score → 2030 → 2050 score change

Indicator	Key findings per route				
Technology readiness	Biomethane	Low			High
	E-furnace				
	H ₂ furnace				
	Biomethane-fired furnaces and high temperature electrical furnaces are commercially available, H ₂ furnaces are currently mostly available, but will further mature to 2050				
Infra-structure availability	Biomethane				
	E-furnace				
	H ₂ furnace				
	Infrastructure availability is expected to improve towards 2050 as grid constraints ease and H ₂ networks expand, though regional gaps are expected to remain.				
Asset cycle	Biomethane				
	E-furnace				
	H ₂ furnace				
	Biomethane is largely a drop-in solution, while e-furnaces and H ₂ require moderate asset upgrades.				

Abatement cost compared to reference route (EUR / tCO₂e)



Conclusion: E-furnaces emerge as the lowest-cost carbon neutral pathway towards 2050, benefiting from a higher efficiency and lower power prices (as assumed in study). While hydrogen remains less cost-competitive than biomethane, its relative economics are expected to strengthen over time.

Main findings on biomethane demand potentials

1. Electrification is expected to be the dominant abatement pathway for most high-temperature heat applications, driven by superior cost competitiveness.
2. Biomethane is likely to remain a material energy source, particularly in sectors with significant residual gas demand, with demand estimated at ~9 bcm in 2050. Hybrid solutions combining electricity and biomethane are also expected to emerge⁶.
3. Hydrogen may play a role in specific applications, although widespread uptake will depend on achieving better cost competitiveness.

Year	Estimated biomethane demand potential (bcm)
2030	3
2040	8
2050	9

Notes

⁶ Hybrid heating solutions are already deployed in sectors such as aluminium and glass, where electricity and gaseous fuels are used in combination.



Annex

Overview of assumptions

Elaboration on main sources and assumptions for the development of the price sets

Creation of the commodity price sets

Energy prices are a key determinant of the relative cost of different routes towards climate-neutral industrial production. At the same time, long-term prices for natural gas, electricity, hydrogen and biomethane are inherently uncertain and depend on developments in commodity markets, technology costs, infrastructure, policy and the wider energy system.

For this reason, the price assumptions used in this study should **not be interpreted as forecasts**. Instead, plausible price ranges were developed for 2030, 2040 and 2050. The price ranges and their main sources are shown in Table 2 below.

From these ranges, two **price sets** were constructed:

- a **main price set**, used for the central analysis and the biomethane demand estimates presented in the main results; and
- a **sensitivity price set**, representing a situation in which biomethane remains relatively more competitive compared with electricity and renewable hydrogen. The sensitivity was used to test how strongly the results depend on uncertain future developments in the relative prices of these energy carriers.

The following paragraphs explain how the price ranges and price sets were established.

Establishing the price ranges

For each energy carrier, a plausible price range was established for 2030, 2040 and 2050. The ranges were based on a combination of current market prices, forward markets, European energy scenarios, published studies and project-specific analysis. The type of evidence differed by energy carrier, reflecting differences in market maturity and the availability of forward-looking price information.

Where liquid markets and forward prices were available, notably for natural gas and electricity, these provided an important reference point. For less mature markets, particularly renewable hydrogen and biomethane, published scenarios and production-cost assessments played a larger role. Carbon-price assumptions were based on European Commission modelling of the EU ETS and the EU's longer-term climate targets.

Natural gas

Natural gas prices were informed by a combination of current Dutch TTF prices, forward-market information, TYNDP-related scenarios and EU impact assessments. The resulting range of €22–45/MWh was retained across the three assessment years. For 2030, observable market and forward prices provided a relatively direct basis for the range. For the longer term, the scenarios from the [TYNDP 2022 Scenario Report](#) (Table 6) and [European Commission modelling](#) were used to assess whether this range remained plausible

Table 2. Ranges for plausible future energy and carbon prices, used to develop the price sets used in the analysis. All prices are expressed in €₂₀₂₅. Infrastructure costs were treated separately where relevant and are therefore not included in the commodity prices presented below.

Energy carrier / carbon value	2030	2040	2050	Main source(s)
Natural gas	€22–45/MWh	€22–45/MWh	€22–45/MWh	EEX / Dutch TTF market and futures data; sense check against EU scenario assumptions
Electricity	€50–75/MWh	€60–70/MWh	€45–65/MWh	EEX futures for nearer years; TYNDP for the long-term outlook
Green hydrogen	€139–209/MWh	€105–192/MWh	€87–139/MWh	IEA hydrogen outlook and market/technology cost evidence
Biomethane	~€89/MWh	~€94/MWh	€79–88/MWh	BIP analysis for different sizes of anaerobic digestion plants; IEA for gasification
Carbon price	€100/tCO ₂ e	€253/tCO ₂ e	€306/tCO ₂ e	EU ETS / European Commission impact assessments

Natural gas (continued)

For the main analysis, a natural gas price of approximately €30/MWh was used across the assessment period. Maintaining a stable central gas-price assumption reduced complexity in the fossil reference case, allowing the analysis to focus on changes in the economics of the alternative production routes. During the development of the assumptions, this value was also compared with higher contemporary market prices. The difference was considered insufficient to materially change the main conclusions of the study.

Electricity

Electricity prices were informed primarily by forward-market data for the nearer time horizons and European energy-system scenarios for the longer term. EEX market data provided the principal reference for 2030 (values for the year 2030) and 2040 (values for the year 2036), while the 2050 range was informed by the [TYNDP 2022 Scenario Report](#) (Figure 26).

This resulted in ranges of €50–75/MWh in 2030, €60–70/MWh in 2040 and €45–65/MWh in 2050.

These ranges were not intended to suggest that uncertainty around electricity prices decreases towards 2050. Rather, they reflected the range of evidence used to construct the assumptions. Forward-market information is available for the nearer assessment years, whereas the 2050 assumption necessarily relied more strongly on energy-system scenarios.

Renewable hydrogen

Renewable hydrogen prices are subject to greater uncertainty because a mature and liquid European renewable hydrogen market has yet to develop. The ranges were therefore not taken directly from a single external source. Instead, they were developed using a combination of European market observations, the IEA Hydrogen Outlook (2026) and expert judgement.

The analysis assumed a downward price trajectory as renewable hydrogen production scales up, resulting in ranges of €139–209/MWh (€4.6–7.0/kg) in 2030, €105–192/MWh (€3.45–6.3/kg) in 2040 and €87–139/MWh (€2.9–4.6/kg) in 2050. The underlying cost analysis also applied a typical cross-sector 15% producer margin when translating production costs into an indicative market price.

For consistency across industrial applications, renewable hydrogen was treated as a market-priced commodity rather than assuming dedicated on-site hydrogen production for each industrial facility, assuming the development of a global market. This allowed the study to compare hydrogen with other energy carriers on a consistent basis.

Biomethane

Similar to the price of renewable hydrogen, future biomethane prices cannot be derived from a sufficiently liquid long-term forward market.

Biomethane market prices were therefore estimated from the underlying cost of producing biomethane.

Production-cost assumptions were based on a previous cost analysis by the [Biomethane Industrial Partnership](#) (2023, p. 5) for Anaerobic Digestion, and on cost estimates by [IEA](#) (2025, figure 2.5) for Gasification. For AD-based biomethane, production costs depend partly on plant size, as larger installations can benefit from economies of scale. To reflect differences in the current structure of biomethane production across Europe, plant-size assumptions were differentiated by country.

The average biomethane production capacity in each country was derived from the EBA Statistical Report (2025). Countries with a current average production capacity below 500 m³/h were assigned the cost characteristics of a medium-sized AD plant (€100 / MWh), while countries with an average capacity of 500 m³/h or more were assigned the cost characteristics of a large-sized AD plant (€70 / MWh).

The resulting country-level production costs were combined with assumptions on the future European production mix, using the potential development of the European sustainable production mix from the recent study by Guidehouse (2026). This approach recognises that the relative contribution of the different production technologies can change over time.

A typical cross-sector profit margin of 15% was assumed to approximate a market price. This resulted in biomethane prices of approximately €89/MWh in 2030, €94/MWh in 2040 and €88/MWh in 2050 in the central assumptions. In the sensitivity price set a 10% price reduction was applied for 2050.

Carbon price

The carbon-price assumptions were derived from [European Commission impact assessments](#) (p. 43, table 4) and were selected to represent progressively stronger incentives to reduce fossil greenhouse gas emissions towards climate neutrality.

The study used carbon values of €100/tCO₂e in 2030, €253/tCO₂e in 2040 and €306/tCO₂e in 2050. The higher values in 2040 and 2050 were deliberately selected to reflect scenarios consistent with increasingly stringent European climate objectives. These values should not be interpreted as forecasts of future EU Allowance prices. They represent modelling assumptions used to assess the economics of fossil and climate-neutral production routes under progressively stronger carbon constraints. The study does also not consider impacts from potential changes in free allocation of allowances.

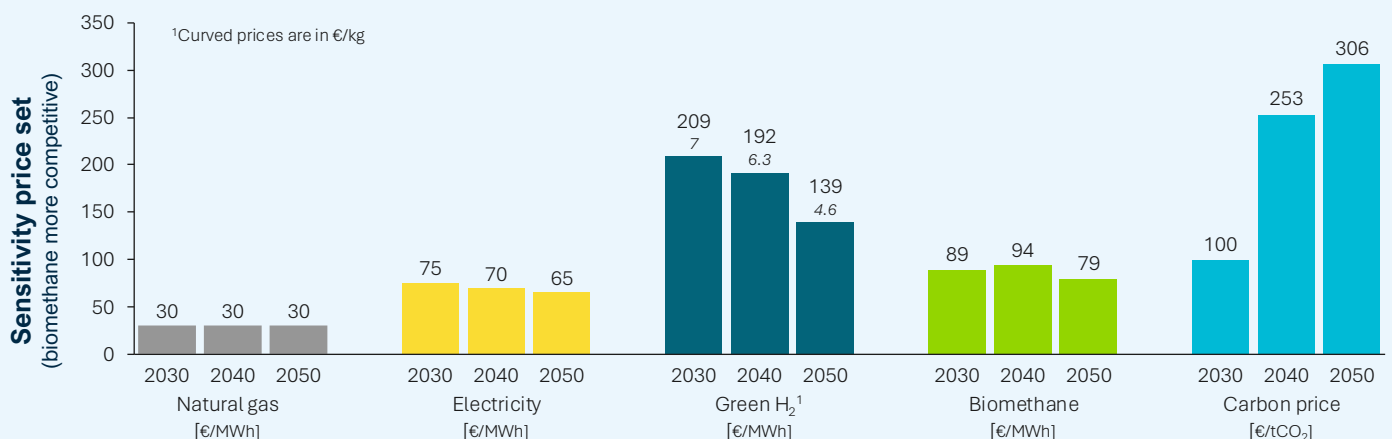
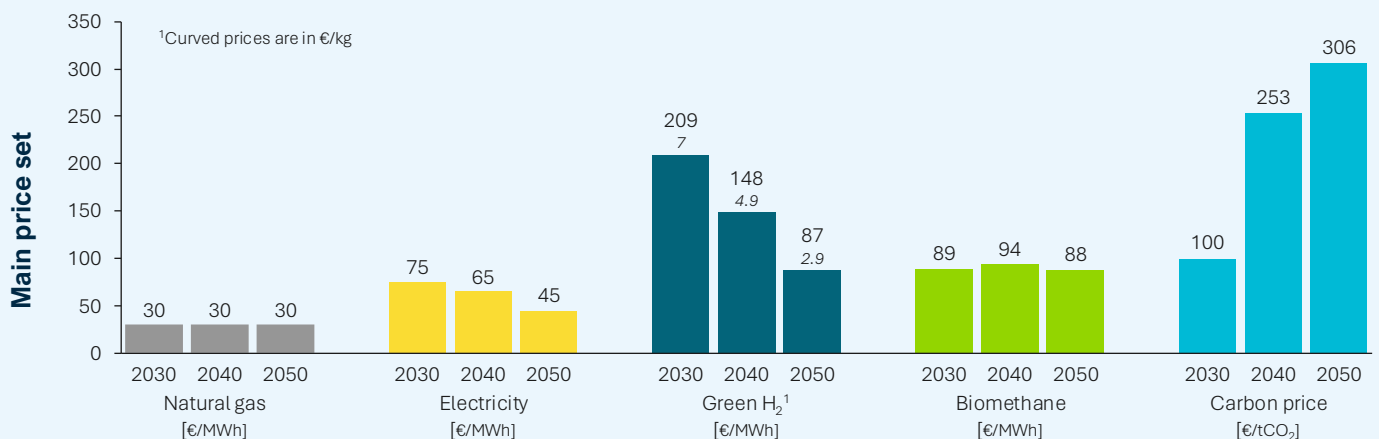
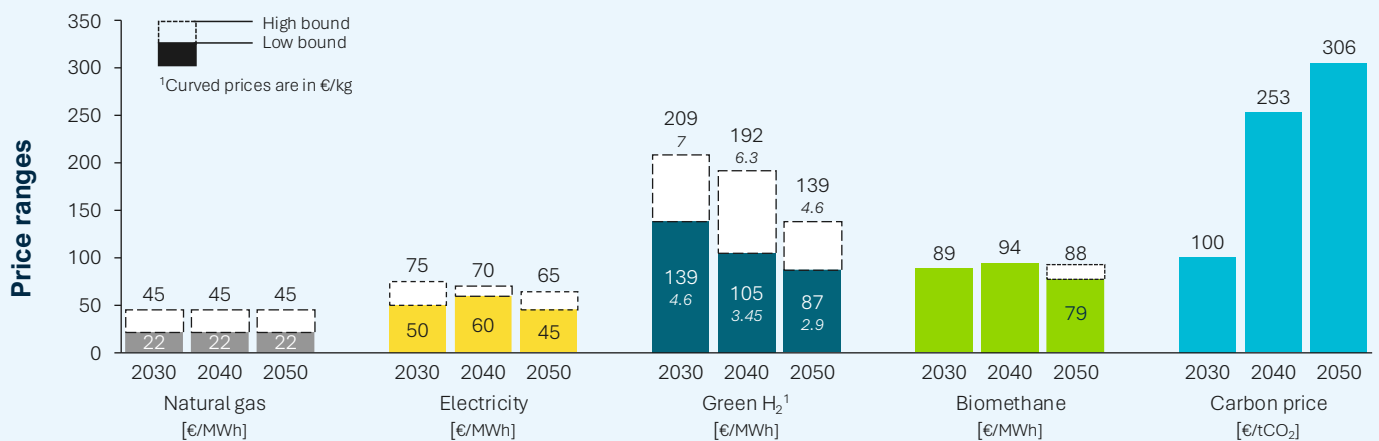
Construction of the price sets

The individual price ranges were used to construct internally consistent combinations of assumptions rather than independently selecting high or low values for each energy carrier.

The **main price set** represented a future in which the prices of climate-neutral energy carriers gradually converge as technologies and markets mature. Natural gas remained at approximately €30/MWh, while electricity and particularly renewable hydrogen became progressively more competitive towards

2050. Biomethane prices remained comparatively stable. The resulting set was used for the central analysis.

A second **biomethane-competitive sensitivity price set** was used to test conditions under which biomethane retained a stronger relative cost position. In this case, electricity remained towards the higher end of its assumed range, while the decline in renewable hydrogen prices was slower. A somewhat lower long-term biomethane price was also considered, reflecting the potential for cost reductions.



Infrastructure cost assumptions

Infrastructure costs have been included in the TCO analysis separately from the underlying commodity prices. Depending on the energy carrier or production route, these costs cover transport, network use and storage. The assumptions were applied to the corresponding energy or feedstock requirements in each production route.

Electricity network costs are based on [Eurostat \(2026\)](#) data for EU-27 non-household consumers in consumption band IF (70–150 GWh/year). The 2025 network cost of €18/MWh was used as the starting point. Network costs were assumed to increase by 25% in 2030, 50% in 2040 and 100% in 2050, resulting in costs of €22/MWh, €27/MWh and €36/MWh respectively. The assumed increase towards 2050 reflects the potential increase in electricity network costs associated with higher grid investment requirements and was informed by an [ACER \(2025, p. 4\)](#) study.

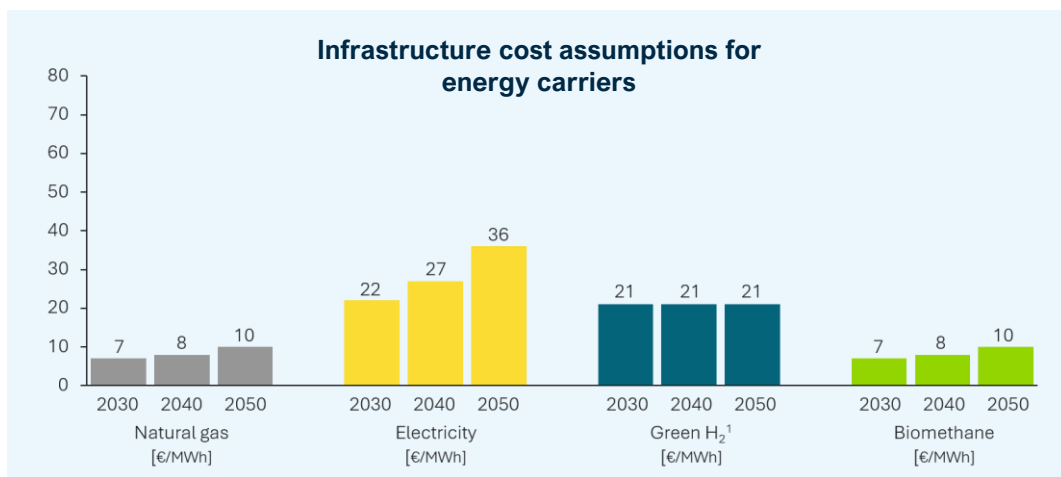
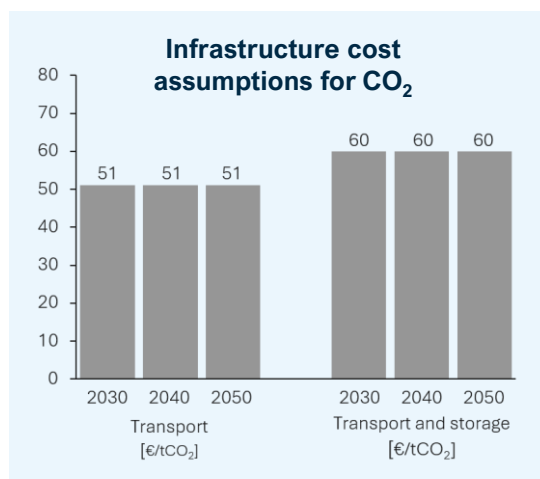
For **hydrogen** transport and storage, a combined infrastructure cost of €21/MWh was applied throughout the assessment period. The transport component was based on the [European Hydrogen Backbone \(2022\)](#), while hydrogen storage costs were based on an assumed storage capacity cost of €50/MWh/year and five storage cycles per year. The resulting assumed cost for storage was €10/MWh. No change in hydrogen transport and storage costs was assumed between 2030 and 2050.

Natural gas network costs were based on [Eurostat \(2026\)](#) data for EU-27 non-household consumers in consumption band I5 (1–4 PJ/year). The 2025 network cost of €3/MWh was used as the starting point. Network costs were assumed to increase by 25%, 50% and 75% relative to the 2025 value in 2030, 2040 and 2050 respectively as European gas consumption declines. In addition, a storage cost of €2/MWh was applied in each assessment year, based on an assumed storage capacity cost of €10/MWh/year and five storage cycles per year. Combined, these assumptions result in natural gas transport and storage costs of €7/MWh in 2030, €8/MWh in 2040 and €10/MWh in 2050.

Biomethane was assumed to make use of the existing gas infrastructure and was therefore assigned the same transport and storage costs as natural gas: €7/MWh in 2030, €8/MWh in 2040 and €10/MWh in 2050. Grid-connection costs at the biomethane production site were assumed to be reflected in the biomethane production cost and were therefore not added separately to the industrial consumer.

For production routes requiring externally sourced CO₂ as a **carbon feedstock**, a transport cost of €51/tCO₂ was applied throughout the assessment period. The assumption covers transport by pipeline, rail or truck. It represents the cost of transporting CO₂ to the industrial user and does not include permanent storage. The assumption was based on an [ERM \(2025, fig. 5\)](#) analysis of European CO₂ transport costs for Transport & Environment.

For production routes involving **permanent storage of captured CO₂**, a combined transport and storage cost of €60/tCO₂ was applied in all assessment years. This assumption was based on the [Clean Air Task Force CCS Cost Tool](#).



Combined costs assumptions of energy prices and infrastructure

