IFRI STUDIES

CENTER FOR ENERGY AND CLIMATE

JUNE 2026

The European Biomethane Sector at a Critical Juncture: Stronger Policy Alignment Will Matter

Sylvie CORNOT-GANDOLPHE

ISBN: 979-10-373-1234-1

How to quote this publication:
Sylvie Cornot-Gandolphe, "The European Biomethane Sector at a Critical Juncture: Stronger Policy Alignment Will Matter", *Ifri Studies*, Ifri, June 2026.

Ifri

27 rue de la Procession 75740 Paris Cedex 15 – FRANCE

Tel. : +33 (0)1 40 61 60 00 – Fax : +33 (0)1 40 61 60 60

Email: accueil@ifri.org

Website: Ifri.org

Author

Sylvie Cornot-Gandolphe is an independent consultant on energy and raw materials, focusing on international issues. Since 2012, she has collaborated with the Center for Energy and Climate of the French Institute of International Relations (Ifri) as a research associate, with CEDIGAZ, the international center of information on natural gas of IFPEN, and with CyclOpe, the reference publication on commodities.

Sylvie has a deep understanding of global gas and coal markets, gained during her past positions at CEDIGAZ/IFPEN, the UN/ECE, the IEA and ATIC SERVICES. She is the author of several reference publications on energy markets. Sylvie graduated from École nationale supérieure du pétrole et des moteurs (ENSPM).

Executive summary

The European biomethane sector is at a critical juncture. Since Ifri published its first biomethane assessment in 2019, the industry has undergone a rapid transformation driven by European Union (EU) decarbonization objectives, security-of-supply concerns, methane reduction policies, and rising pressure to produce low-carbon energy domestically. These structural policy drivers have made biomethane a strategic asset for the European energy transition. It is a dispatchable, storable, domestically produced drop-in substitute for natural gas. It is the only renewable gas that can be immediately deployed at scale, using existing infrastructure. Biomethane delivers deep—sometimes negative—emissions reductions while providing system-wide socioeconomic and local benefits. It can help reduce dependence on imported fertilizers.

European biomethane production has more than doubled since 2019, reaching 5.2 billion cubic meters (bcm) in 2024, including 4,3 bcm in the EU. Europe leads global biomethane production, accounting for half of the global output. Total planned investment by investors and project developers rose to €28 billion as of June 2025, an increase of €1 billion compared with the previous year, reflecting confidence in the sector's long-term potential. These investments are projected to deliver an additional 7.3 bcm/y of biomethane capacity to Europe by 2030, lifting the EU's production to 10 bcm. Only 15 Member States have clear, quantified national biomethane targets for 2030, which add up to 17.1 bcm. Considering the National Energy and Climate Plans (NECPs) targets, when explicitly mentioned, and making some assumptions for countries with no specific targets, EU biomethane production could reach 21 bcm in 2030.

The potential for European biomethane is even higher. Sustainable feedstocks could supply up to 35 bcm by 2030, with much larger volumes by 2040–2050 (up to 205 bcm/y in 2050). This growth would be mostly driven by anaerobic digestion, supplemented by gasification technology and e-methane after 2030. However, competition is growing between end-use sectors as the pressure to decarbonize the entire economy intensifies. In addition, competition for some feedstocks will increase as other bioenergy sectors, particularly sustainable aviation fuel (SAF), tap into the same biomass resources as biomethane based on thermal gasification. Nevertheless, the consensus is that the overall potential remains high and largely untapped.

Costs remain a central challenge. After early declines, there has been no sustained EU-wide reduction in biomethane production costs since the late 2010s due to inflation, higher operational expenditure (OPEX), and rising project complexity. Biomethane production costs can vary significantly depending on feedstock, location and, above all, the plant size. European current production cost is estimated at €75-80/MWh on average. Economies of scale, technological innovation/yield improvement, industrialization of equipment manufacturing, and standardization are essential to future cost reductions.

To offset the higher cost of biomethane compared to natural gas, subsidies for biomethane production were crucial for the initial growth of the market, and they are still necessary for new European biomethane markets. However, policy frameworks are shifting from subsidy-based models to market-driven mechanisms to reduce pressure on national budgets. Demand-side obligations in transportation, such as the greenhouse gas (GHG) quota in Germany, and biomethane blending mandates for gas suppliers, create a large market in which the environmental value of biomethane is recognized through certificates. In these compliance-driven markets, consumers bear the cost premium of biomethane instead of all taxpayers. Biomethane purchase agreements (BPAs) are also emerging as a new merchant model, providing developers with financial certainty and enabling off-takers (primarily hard-to-abate industries) to decarbonize their operations and fulfill their sustainability commitments.

Biomethane has significant positive externalities, meaning its true value goes beyond energy substitution. Monetizing these benefits via biomethane certificates is crucial for competitiveness. These certificates can be very valuable, especially for low-carbon intensity biomethane, sometimes exceeding full-production costs. But their prices can be highly volatile. Biomethane by-products are increasingly valorized. Biogenic CO_2 is captured and sold for industrial applications, and more and more as an input for e-fuels production. Nutrient-rich digestate, when rightly controlled, is gaining recognition as a biofertilizer, enhancing soil health, reducing imports of synthetic fertilizers, and improving agricultural circularity.

Given competition for sustainable feedstocks, national policies should prioritize biomethane deployment in applications where other decarbonization alternatives are not viable within a reasonable timeframe, or technically unfeasible, and where biomethane delivers the greatest system value and emissions-reduction impact. Across multiple European analyses, four priority applications emerge, where biomethane is often the only immediately deployable solution capable of delivering deep emissions:

- For buildings where electrification is not feasible due to technical or financial constraints, biomethane offers a practical decarbonization solution. It leverages existing gas networks' ability to manage peak and seasonal demand.
- High-temperature industrial heat processes and chemical feedstock.
- Heavy-duty road transport and maritime transport via bio-liquefied natural gas (LNG).
- Flexible, dispatchable power generation.

Biomethane injection into the grid is a no-regret option for delivering renewable, flexible, dispatchable, storable energy at scale and enabling cross-sector decarbonization. As 2030 decarbonization targets approach —and with high compliance costs looming under the EU Effort Sharing Regulation—, the decarbonization of transport and buildings has become a top priority for national policymakers. For the biomethane use hierarchy, this clearly points to transport and buildings as the immediate priority —the sectors where decarbonization has lagged and where biomethane can deliver rapid, high-value emissions reductions. In the longer term, biomethane's end-use versatility and storability allow it to adapt to the needs of a fully decarbonized energy system, including supporting clean hydrogen production and balancing variable renewable generation.

Despite strong structural drivers, the sector is still held back by inconsistencies in European Commission (EC) regulations and several persistent barriers. These include regulatory fragmentation, permitting delays, grid congestion, challenges in feedstock sourcing, a lack of market harmonization, and financial constraints. Under current policies, the EU is unlikely to meet its ambition of producing 35 bcm of biomethane by 2030. Yet the EU's biomethane production could reach 21 bcm in 2030, taking into account the targets specified in the NECPs and making assumptions for countries without specific targets.

The full potential of the sector can only be realized if policymakers address the barriers restraining the rapid deployment of biomethane. The analysis of national biomethane markets in the seven countries with the highest biomethane production potential shows that in most of the countries where biomethane deployment had stalled or lagged expectations, a wave of regulatory reforms introduced since early 2026 is now unlocking investment, easing permitting and grid access, and positioning the sector for faster scale-up through the decade.

With coherent political direction, harmonized rules, and effective support, biomethane can become one of Europe's most powerful tools for cost-effective decarbonization of the hardest-to-abate end-use applications and for providing the flexibility essential to a decarbonized energy system. It is time for EC policymakers to provide a level playing field for biomethane, a no-regret option that strengthens Europe's resilience, strategic autonomy and decarbonization.

Table of contents

Introduction: current state of the European biomethane sector

As Europe intensifies its efforts to decarbonize its energy systems, reduce its hydrocarbon imports and raise its industrial competitiveness, biomethane is increasingly recognized as a pivotal component of the energy and climate objectives. Biomethane, a domestic renewable energy source and a drop-in fuel for natural gas, offers a sustainable alternative to fossil fuels, contributing to energy security, greenhouse gas (GHG) mitigation, waste management, and resilient and circular agriculture, while providing several socio-economic advantages.

Driven by strong policy drivers, European biomethane production has registered a compound annual growth rate of 17% since 2019. According to the European Biogas Association (EBA),[1] it reached 54 terawatt hours (TWh) or 5.2 bcm in 2024, up 9% over 2023, of which 4.3 bcm was produced in the European Union (EU). Europe leads global biomethane production, accounting for half of global production.

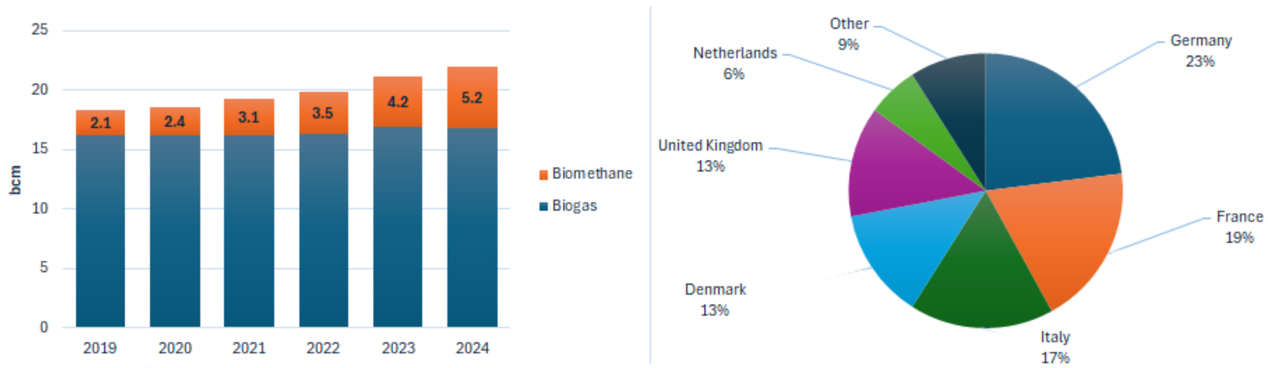
Combined biogas and biomethane production reached 232 TWh (22 bcm) in 2024, i.e., 5.1% of European natural gas consumption (430 bcm in 2024, of which 313 bcm in the EU), underscoring the growing role of biogases in Europe's energy mix. For biomethane alone, this share is still marginal (1.4% at the EU level), but some countries have already achieved a greater share (Denmark with 32%). Today, most newly built biogas plants are combined with upgrading plants to produce biomethane. At the beginning of 2025, Europe's installed biomethane production capacity stood at 7 bcm/y, with around 1,700 operational biomethane plants spread across 25 European countries. The average plant size has increased over time, reaching 483 normal cubic meters per hour (Nm^3/h) in 2024. However, there are significant differences across European countries. France leads in terms of the number of plants (731), but these are relatively small (250 Nm^3/h), whereas Denmark has fewer plants (58), but with substantially larger size (1500 Nm^3/h).

Despite this expansion, the deployment of biomethane varies significantly among European countries, driven by feedstock potential, national policies and financial incentives. Six countries account for above

1. Unless stated otherwise, all data presented in this section are drawn from the European Biogas Association (EBA)'s Statistical Report 2025.

90% of European biomethane production: Germany, France, Italy, Denmark, the United Kingdom (UK) and the Netherlands. Since 2025, France has surpassed Germany as the top producer and has over 1,100 projects in development, indicating significant potential for future growth.[2] The concentration of biomethane production is due to the lack of incentive schemes in many Member States (MS). An increase in policy support, demand-side incentives, the emergence of a cross-border market and the increasing price of EU Emission Trading Scheme (ETS) allowances are accelerating investments in MS with (almost) no production today.

Graph 1: Biogases production in Europe, 2019-2024, and biomethane production in Europe by countries in 2024



Source: EBA.

Biomethane can be injected into the gas grid (at either the distribution or transmission level), compressed into bio-compressed natural gas (CNG) or liquefied into bio-liquified natural gas (LNG), for use in the transport sector mainly. Today, grid injection is the main outlet for biomethane, with at least 86% of the operating plants connected to the gas grid.[3] Pushed by EU decarbonization policies on transportation, there is a growing interest in bio-LNG. There were 101 bio-LNG plants in operation in Europe at the end of 2024, with a production capacity of 15 TWh/y, compared to only 1.5 TWh/y in 2022.

Financially, the sector is robust. According to the EBA's Biomethane Investment Outlook 2025, total planned investment has risen to €28 billion, an increase of €1 billion compared with the previous year.[4] Of this, €24.2 billion is allocated to new, greenfield projects. The largest planned investments are in Spain (€4.8 billion), Denmark (€3.14 billion), the UK (€2.4 billion), and France (€1.7 billion). These investments are projected to deliver an additional 7.3 bcm/y of biomethane capacity to Europe by 2030.

2. C. Got and S. Wellenreiter, "Tableau de bord : biométhane injecté dans les réseaux de gaz. Quatrième trimestre 2025" [Dashboard: Biomethane Injected into Gas Networks. Fourth Quarter 2025], *StatInfo énergie*, No. 796, Service des données et études statistiques, February 2026.
3. "Biomethane Map 2025", Gas Infrastructure Europe/EBA, 2025.
4. "Biomethane Investment Outlook 2025", EBA, 2025.

The transport sector dominates biomethane use

A lack of aggregated data makes it difficult to clearly understand where biomethane is used across European sectors. Data from EBA show that biomethane consumption is dominated by the transport sector, which accounted for 25% of biomethane use in 2024. This was followed by the building sector (18%), power generation (15%) and industry (14%), while the end-use of the remainder (28%) is unknown, introducing some uncertainty into the actual breakdown of European consumption.

The transposition of the Renewable Energy Directive (RED II) into national legislation has driven the use of advanced biomethane in EU road transport (e.g., the German GHG quota, the Biomethane Ministerial Decree of 2018 in Italy). These schemes are now revised to incorporate the provisions of RED III into national legislation.

The sectoral applications of biomethane are not uniform across Europe. Instead, the role of biomethane varies significantly between countries, depending on strategic priorities and national support schemes, reflecting its societal value, resource availability, consumers' demand and the extent of gas grid infrastructure. Driven by previous support schemes targeting the production of electricity and heat in combined heat and power (CHP) plants, a large share of biomethane production –although declining– is used in CHP plants in Germany, while most biomethane production is used in the heating sector in the UK, and all current biomethane production is consumed in the transport sector in Italy. In France, end-uses of biomethane are more diversified and include residential heating (27%), transport (24%), industrial sector (28%) and urban heating networks (5%).

This diversity underscores the importance of tailored national approaches to maximize biomethane system value.

Agricultural residues are the dominant inputs for biomethane production

In terms of feedstock, while energy crops, including monocrops, initially dominated the feedstock mix for biomethane production, this has changed radically since 2017. Although still used in existing plants in some countries, energy crops have largely been phased out of use in European biomethane plants constructed since 2017 due to the introduction of stricter sustainability criteria in RED II and the decision made by major European biogas-producing countries to reduce incentives and manage the use of monocrops (e.g., deletion of the bonus for energy crops in Germany). RED III tightens verification, traceability and sustainability requirements.[5]

Since 2017, there has been a clear trend towards the use of agricultural residues, organic municipal solid waste (MSW), sewage sludge and industrial waste in new plants. According to Sia Partners,[6] agricultural residues are the dominant inputs for biomethane production, accounting for 50% in 2024 of biomethane production in major European producing countries. These are followed by organic waste (21%), energy crops (21%), sewage sludge, a by-product of wastewater treatment plants (6%) and landfill (2%). Feedstock use varies significantly by country. For instance, in Norway, 80% of the plants are using sewage sludge, while in Germany, 44% of the plants rely on energy crops, followed by manure with 15%, sewage sludge with 13% and MSW with 12%.

New concepts to overcome negative land change impact and improve soil use efficiency and farm sustainability have gained traction. For instance, in Italy, most biogas-producing farms use the BiogasDoneRight® concept. The concept is built around the growth of a secondary crop that is used to produce biogas, without impacting the yield of the primary crop.

Cross-border trade is emerging

Since 2022, boosted by high natural gas prices, the EU ETS, national trading systems (e.g. in Germany), and the launch of European schemes to facilitate the transfer of biomethane certificates (Box 1), cross-border trade has emerged and has taken place between more countries. Cross-border trade is estimated at some 9 TWh in 2024, meaning that less than 2% of biomethane is consumed outside of its country of production. Germany, Switzerland and Sweden are the largest importers of certificates, while Denmark dominates exports, followed by the UK and the Netherlands. Biomethane certificates from France, Slovakia, Spain and the Czech Republic are also increasingly being traded.[7]

5. RED III introduces higher GHG-saving thresholds (70–80%) for biomass fuels used in electricity, heating and cooling. The GHG-saving thresholds for biomethane marketed as a transport biofuel remain those established under RED II (50–65%), though RED III tightens verification, traceability and sustainability requirements.
6. "8th European Biomethane Benchmark", Sia Partners, 2025.
7. "Biomethane Barometer 2025", Deutsche Energie-Agentur, 2025.

Box 1: Biomethane certificates

Two kinds of certificates co-exist: Guarantees of Origin (GOs) and Proof of Sustainability (PoS), which serve different roles under different regulations and are, therefore, not mutually exclusive.[8] These certificates assign a monetary value to the environmental attributes of biomethane.

- GOs are used to certify the renewable origin of biomethane for consumers under the RED, and they are normally used in voluntary markets on a book-and-claim basis. Under the book-and-claim principle, GOs are transferred separately from physical gas between producer/trader/end-user accounts in the national registry. Two transnational platforms, operated by the European Renewable Gas Registry (ERGaR)[9] and the Association of Issuing Bodies (AIB),[10] facilitate cross-border transfers of biomethane certificates between national registries.
- PoS is the key certificate recognized by the EC to comply with mandates and renewable targets. It certifies compliance with sustainability requirements under the RED on a mass-balancing basis. Under the mass balancing principle, PoS and physical gas cannot be separated. Mass balancing ensures that certified biomethane leaving a supply chain has been added to it in equal quantities. This system avoids double-counting risk and requires detailed records of biomethane transport, conversion processes and other factors. Sustainability certification schemes must be approved by the EC.

Important changes lie ahead in the landscape of tracking certificates. Starting with years of delay and now expected in 2026, the EU Union Database for Biofuels (UDB), launched in 2024 for registration, will improve the traceability of mass-balanced biomethane with PoS disclosure.

Strong EU regulatory framework, but some inconsistencies and gaps

Since the Green Deal was adopted in 2019, the European energy and climate framework has evolved tremendously. Security of supply and affordability have regained importance, along with sustainability. New policy drivers have emerged, making sustainable biomethane a key component of the future decarbonized energy mix, ensuring security of supply and industrial competitiveness. Numerous directives and plans have been adopted by the EC. Some of them, like the REPowerEU plan, the amending Directive EU/2023/2413 (RED III), the EU Emissions Trading System (ETS and ETS2),

8. "Renewable Gas Tracking Systems: Value of Biomethane/RNG Certificates", *Commodity Insights*, S&P Global, October 2024. Report prepared for EBA, Eurogas, ERGaR, and the US Renewable Natural Gas (RNG) Coalition.
9. See: www.ergar.org.
10. See: www.aib-net.org.

the FuelEU Maritime Regulation, the Hydrogen and Decarbonized Gas Market Package (the Gas Package), and the Clean Industrial Deal, are particularly relevant for the development of the European biomethane sector, driving not only production growth, but also directing its sectoral uses (Table 1).

Europe has a strong overarching framework for biomethane. However, EC policies are not consistent, and there are still regulatory, market, financial, and operational barriers that collectively slow down biomethane scale-up.[11]

The REPowerEU plan sets a 35 bcm biomethane target by 2030, doubling the "Fit for 55" ambition. Yet neither RED III nor the Gas Package and the REPowerEU roadmap (May 2025) make this target binding, leaving MS without accountability and investors without long-term certainty. In addition, recent EC documents refer to the 35 bcm target as a combined target for biogas and biomethane, diluting the effective ambition. [12]

RED II/III promotes biomethane in road transport, but regulations based on tailpipe emissions of vehicles and timelines for zero-emission heavy-duty vehicles (HDVs) create regulatory conflict.

Funding disparities persist, with biomethane receiving less attention and financial support than other renewables such as solar, wind, or green hydrogen –slowing deployment and investment.

RED III pushes for greater unification and growth of biomethane cross-border trade, notably through the establishment of the EU-wide UDB for gaseous fuels. However, although the UDB was officially online on November 21, 2024, it is not yet fully mandatory for biomethane transactions, with the EC still finalizing the enforcement timeline. There are still some hurdles to be solved (notably transport through extra-EU grids). Delays in rolling out the UDB and the lack of harmonization of certification complicate cross-border trade, drive up administrative costs, and create uncertainty that can dampen investment.

Despite growing momentum, the 35 bcm target will not be met. The final updated National Energy and Climate Plans (NECPs) clearly show an acceleration in biomethane production over the decade. While almost all MS mention biomethane in their NECPs, only 15 of them have clear, quantified national biomethane targets for 2030,[13] which add up to 17.1 bcm production. Some countries have a combined biogases/renewable gases target, some only give a dedicated target for the transport sector, and some (e.g., Germany, the country with the largest potential) have no specific target at all. This makes it

11. M. De Gregorio, *et al.*, "State of Play of Biogas & Biomethane in Europe: An Update on Market Gaps and Policy Recommendations", Report under Horizon Europe joint projects HYFUELUP, BIOMETHAVERSE, SEMPRE-BIO AND METHAREN, Second report, October 2024; M. Boglárká, "Europe's Biomethane Landscape: between Ambition And Reality", *SUERF Policy Note*, No. 384, The European Money and Finance Forum, December 2025.

12. "Biomethane", topics online section, European Commission.

13. Belgium, Czech Republic, Denmark, Estonia, Greece, France, Hungary, Ireland, Italy, Lithuania, Luxembourg, Netherlands, Poland, Romania and Slovakia.

difficult to assess the EU production target. Considering the NECPs' targets, when explicitly mentioned, and making some assumptions for countries with no specific targets, EU biomethane production could reach 21 bcm in 2030.

Table 1: Main directives relevant for the biomethane sector

Regulation / Directive	Year	Main measures related to biogas/biomethane
REPowerEU plan (COM/2022/230)	2022	Political anchor; sets **35 bcm EU biomethane target by 2030**; drives investment for biogas upgrading and grid injection; established the Biomethane Industrial Partnership (BIP) (2022-2025) to coordinate industry, MS, and EC .
Renewable Energy Directive III (RED III) (EU/2023/2413)	2023 (legally binding from 21 May 2025)	Increases the share of renewable energy (RE) in the EU to at least 42.5% by 2030, with a potential target of 45%. **Broadens the biomethane scope to cover all final uses.** **Transport**: raises the required minimum share of RE supplied to the transport sector, including air and maritime segments, to at least 29% by 2030. Alternatively, EU countries can choose to reduce GHG emission intensity by at least 14.5% by 2030. The threshold for renewable fuels of non-biological origin (RFNBOs) and advanced biofuels is raised to 5.5% by 2030 (no double counted in GHG schemes), of which at least 1% needs to be supplied by RFNBOs. **Industry**: annual indicative RE target to be ensured by each Member State: +1.6 point/y; 42% of RFNBO in 2030. **Buildings**: indicative target of RE in buildings: 49% in 2030; heating and cooling incremental sub-target fby at least 0.8 point/y average calculated for the period 2021 to 2025 and 1.1 point/y in the period 2026 to 2030. Strengthens sustainability and GHG reduction requirements. Reinforces the role of biomethane certificates (PoS and GOs) and the UDB. Improves permitting.
FuelEU Maritime (EU/2023/1805)	2025	Introduces **stricter GHG limits for the energy used by ships above 5,000 gross tonnage calling at European ports.** Shipping companies must reduce the GHG intensity of marine fuels by 2% in 2025 and 6% by 2030 (GHG emissions and well-to-wake), increasing progressively to as much as 80% by 2050. Companies that fail to meet annual targets face financial penalties and compliance liability. **Provides flexibility** in achieving compliance cost-efficiently. Introduces a **pooling** mechanism of emissions between vessels(ships that have over-compliance can transfer their surplus emissions to other ships that do not meet the targets). In addition, it is permitted to transfer surplus emission savings into the future without limit (**banking**). These regulations create a strong incentive for sustainable investments in bio-LNG.
Gas Decarbonisation Package (EU/2024/1788 and EU)/2024/1789)	2024 (to be transposed into national law by August 2026)	Core regulatory package shaping biomethane's integration into the EU gas market, **enabling an EU-wide biomethane market** Sets grid access and injection rules for renewable gases. Access to gas networks and markets is prioritized. Cost sharing models between producers and network operators for connection infrastructure. Tariff discounts (up to 100%) for biomethane injection (implementation varies by MS); GOs and PoS systems being harmonised; UDB.
EU Emissions Trading Scheme (ETS) (EC/2003/87/)	2005	Establishes a cap-and-trade carbon market covering emissions from electricity and heat generation, some industrial sectors and aviation, and from 2024 maritime transport; **biomethane can be used in place of natural gas and benefits from a zero-emission value, reducing the ETS costs.**
EU Emissions Trading Scheme (ETS2) (EU/2023/959)	2023 revision	Adds coverage for GHG emissions in sectors not covered by the EU ETS (buildings, road transport and additional industrial sectors); aims to reduce GHG emissions by 42% by 2030 compared to 2005 levels; full operation postponed to 2028 (from 2027 initially).
EU Clean Industrial Deal (COM/2025/85)	2025	**Prioritises affordable, clean, EU produced energy for industry**; Industrial Decarbonisation Accelerator Act streamlines permitting (biomethane plants benefit as part of the clean tech project pipeline); aims to strengthen EU manufacturing capacity for clean technologies (includes equipment relevant to biomethane production); emphasises flexible, resilient, integrated energy systems; EU level financing (**Decarbonisation Bank, Competitiveness Fund**) supports clean tech deployment (biomethane projects eligible under renewable gas and clean industry categories); reinforces circularity and resource efficiency
Waste Framework Directive (EC/2009/98)	2009 amemdement	Obligation to collect organic waste in municipalities separately from 2024; provides an additional feedstock stream for biomethane.
Urban Waste Water Treatment Directive (EU/ 2024/3019)	2024 revision	Requires wastewater treatment plants in urban agglomerations to dramatically improve energy efficiency and increase on-site renewable energy generation, supporting the reuse of treated waste water and sewage sludge for biomethane.

Source: Author.

In 2019, Ifri published its first report on biogas and biomethane based on the assessment of three key markets (Germany, Italy and Denmark).[14] The report concluded on the necessity to achieve production cost reductions and better sectoral integration, control subsidy costs, and clarify the long-term role of biogas and biomethane for the energy sector and beyond. Since 2019, the energy landscape has changed dramatically, but some issues addressed in the 2019 report are still valid. This note is an update to the 2019 report, focusing on Europe. It assesses the prospects for the further development of biomethane in Europe, highlights the potential and challenges and makes recommendations on the way forward.

14. M.-A. Eyl-Mazzega and C. Mathieu (eds.), "Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy", *Études de l'Ifri,* Ifri, April 2019.

High sustainable feedstock potential, but competition is coming

High sustainable biomethane production potential

Several recent reports have assessed the European sustainable biomethane production potential, meeting the sustainability requirements mandated by the RED. These assessments confirm that the potential of sustainable biomass to reach the 35 bcm target by 2030 is already there, using feedstocks that do not displace food production or land use.

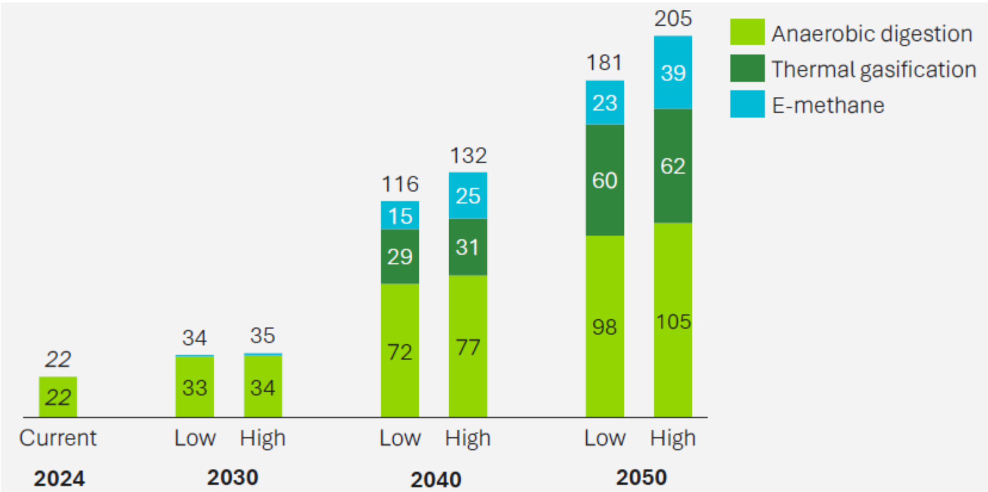
The International Energy Agency (IEA)'s 2025 report, Outlook for Biogas and Biomethane,[15] which provides an assessment of the sustainable technical potential and costs of biogases (biogas and biomethane) supply globally, concludes that the EU 27 has a strong resource base for biomethane, especially from manure, biowaste and woody biomass. The current EU potential for biogases is assessed at 51 billion cubic meters of natural gas equivalent (bcme).[16] The EU produced some 20 bcme of biogases in 2024. As such, the region utilizes 40% of its overall current sustainable potential.

In a 2024 report on Europe's biomethane potential,[17] Guidehouse estimated that Europe could produce up to 44 bcm of biomethane in 2030 (41 bcm in the EU), of which 41 bcm is for anaerobic digestion (AD) and 3 bcm from thermal gasification. In a recent study, updating the 2024 report and incorporating current market and regulatory insights, Guidehouse now estimates the total potential of biomethane and e-methane in 2030 at 34-35 bcm/y (of which 31-32 bcm/y in the EU), almost exclusively based on biomethane from AD.[18] Thermal gasification is no longer considered to be close enough to commercialization to make a material contribution in 2030. However, both thermal gasification and e-methane are set to become relevant by 2040. By 2040, Europe could produce 116-132 bcm/y, and up to 181-205 bcm/y in 2050, if the region exploited its full potential (Graph 2). Germany, France, Italy, Poland, Spain, and the UK hold most of the potential.

15. "Outlook for Biogas and Biomethane: A Global Geospatial Assessment", International Energy Agency (IEA), May 28, 2025.
16. One bcme equals 36 PJ based on the lower heating value.
17. "Biogases Towards 2040 And Beyond", Guidehouse, April 2023.
18. "Biogases Europe's Overlooked Path to Energy Independence? Reassessing Sustainable Production Potential", Guidehouse, April 22, 2026.

AD is expected to remain the dominant technology (61% of the potential in 2040 and 53% in 2050). However, the potential for 2030 has been lowered compared to the 2024 report due to a lack of timely action to date to accelerate the deployment of biogases and to mobilize available feedstocks. Faster feedstock identification and mobilization are required to accelerate biomethane production tailored to each country's specificities.

Graph 2: European biomethane & e-methane production potential in 2030, 2040 and 2050



Note: 2024: actual biogases production (biogas plus biomethane).
Source: Guidehouse (2026).

Furthermore, additional potential could be unlocked from novel feedstocks, such as digestate from AD and seaweed, and landfill gas, which will further increase the potential in the short to medium term.

But competition for feedstocks is coming

The sustainability and GHG emission savings criteria established in RED II and RED III ensure a balanced development of bioenergy industries. They do, however, contribute to reducing the available amount of feedstock, thereby increasing competition among players to access feedstock.[19] As a result of growing competition, an increase in the price of agricultural and biowaste residues has been observed in some regions.

Competition for low-carbon intensity (CI) feedstocks is intensifying, especially in countries like the Netherlands and Denmark. This is due to the transposition of RED III into national legislation and the shift to GHG emissions reduction instead of green gas quotas in the transport sector. Low-CI biomethane achieves the highest climate benefits, with manure achieving negative emissions (100g CO_2eq/MJ). Furthermore, the FuelEU maritime

19. "Blunomy's Insights on The Biomethane Market: A Series of Briefs Addressing Key Industry Topics", Blunomy, August 2024.

scheme, which aims to reduce the GHG intensity of marine fuels, also drives demand for low-CI bio-LNG (see Section 6).

The carbon intensity of produced biomethane, mainly determined by the feedstock CI score, is thus becoming a key factor for biomethane values and sales opportunities. This results in a European trend towards market segmentation based on feedstock. Manure paths with particularly low GHG values are becoming premium products – with correspondingly higher prices and better sales opportunities than other feedstock paths.[20] For instance, prices for manure-based Dutch biomethane certificates (unsubsidized), which averaged just under €60/MWh in the first half of 2025, have risen to over €120/MWh at the beginning of March 2026.[21]

In addition, competition for some feedstocks from other bioenergy sectors will grow over time. As noted in Guidehouse's 2026 assessment, some feedstocks are in high demand across other bioenergy and biofuel sectors, which can drive up prices and limit their availability for biomethane production. Agricultural residues, for example, can be used directly for heat and power generation or as inputs for advanced biofuels, such as cellulosic ethanol. Biowaste, high-lignin crop residues and woody biomass are also suitable for other conversion pathways, including sustainable aviation fuel (SAF).

Towards 2030, biomethane will be mainly produced via AD of waste and residues, where competition from other conversion pathways is low. Beyond 2030, thermal gasification will gradually start to play a larger role. The gasification pathway relies on different feedstock than AD. It uses dry, lignocellulosic biomass, such as forestry residues, woody biomass, and lignocellulosic crop residues. Competition with SAF producers may emerge as the aviation sector develops new SAF pathways —Alcohol-to-Jet (AtJ), SAF through gasification-to-Fischer–Tropsch (FT) technologies (FT-SAF) — that rely on the same feedstocks. ReFuelEU Aviation requires increasing SAF blending levels across European airports, creating strong policy-driven demand for SAFs. The regulation mandates that fuel suppliers at Union airports gradually increase the share of SAF blended with conventional aviation fuel, starting with a 2% share in 2025, rising to 6% in 2030 and 20% by 2035, and reaching 70% by 2050 in 2035. Competition for lignocellulosic biomass may raise feedstock prices and reduce availability for biomethane producers, especially as the aviation sector has fewer alternative decarbonization options in the short/medium term (from 2035 onwards, the aviation sector expects to transition to e-SAFs) and a higher willingness to pay due to high compliance penalties.

20. M. Lansdowne, "Why Have European Biomethane Prices Risen By ~80% In Just 9 Months?", Linkedin, February 17, 2026.
21. R. Li and D. Wong Zheng Wei, "Dutch ERE Biotickets Trigger Strong Biomethane Gains", S&P Global, March 5, 2026.

There are also synergies between biomethane and SAF. Bio-SAF can be produced from biogas/biomethane. This can create opportunities for biomethane to be used as a SAF feedstock because of its extremely low carbon intensity and compatibility with FT and e-fuel pathways. Biomethane can provide biogenic CO_2 for power-to-liquid (PtL) synthesis, renewable hydrogen for hydro-processing routes, and renewable intermediates such as biomethane-based methanol. SAF derived from biomethane is still a niche market with a small number of operational plants, but several commercial-scale projects are underway (e.g., Repsol in Spain and TotalEnergies in France, which already integrate biomethane-derived renewable hydrogen into hydro-processing units to produce SAF, PtL plants in Norway, Denmark and the Netherlands that use biogenic CO_2 as the carbon source for SAFs, Verbio's biomethane-to-methanol platform in Germany).

While increasing competition for feedstock is expected, the consensus is that there is still a vast availability of feedstock to produce biomethane in Europe. The main challenge today is to collect these resources. According to the Biomethane Industrial Partnership (BIP) assessment, the 35 bcm target requires collecting 150 Metric ton (Mt) to 200 Mt of sustainable biomass.[22]

Growing competition for some feedstocks emphasizes the importance of ensuring flexible sourcing of feedstocks and securing long-term feedstock resources.

Several partnerships between feedstock owners and biomethane producers have been signed over the past few years to ensure feedstock availability for new biomethane plants (e.g., an agreement between TotalEnergies and the National Federation of Agricultural Holders' Unions (FNSEA) in France). Vertical integration of the value chain (upstream) is also pursued. Using innovative technologies that unlock challenging feedstock potential is also a strategy used to secure feedstock (e.g., TotalEnergies' acquisition of a 20% stake in Ductor in May 2024, a startup that has developed an innovative technology to process high-nitrogen organic waste, such as poultry manure). Major industry players are also entering new geographies such as the Italian, Polish, and Spanish markets, seeking to tap into their vast, underutilized potential (e.g., TotalEnergies' acquisition of the Polish company Biogazowa).

22. "BIP Work Programme", Biomethane Industrial Partnership (BIP), October 2022.

Biomethane production costs mainly depend on scale

Biomethane production costs

Biomethane production costs can vary significantly depending on the plant size, feedstock and location. According to an assessment of real cost data by BIP, production costs range from €54/MWh to €91/MWh for biomethane via AD, the most relevant production pathway for biomethane production.[23] These are 2021 cost levels. Since then, production costs have gone up, yet further innovation may lead to future cost decreases. Economies of scale are strong, especially in capital expenditure (CAPEX): larger plants show markedly lower specific investment per MWh. Medium-scale plants (around 540 Nm^3/h) have an average cost of 87 €/MW, while large plants (>1200 Nm^3/h) have an average cost of €54/MWh. In addition to the cost of production, around €5/MWh must be added for grid injection, and €20-25/MWh if biomethane is liquefied.

Other reports indicate a similar wide dispersion of biomethane production costs. The IEA, which provides supply cost curves for the EU biomethane potential by feedstock, estimates the EU average production cost in 2024 at $22/GJ (i.e., around €73/MWh with an exchange rate of €1= $1.18), while the average cost of producing the cheapest 10% of potential is $15/GJ (€46/MWh).[24] EBA estimates the current cost of biomethane production to be on average €80/MWh.[25] An audit by the French energy regulator (CRE), covering around 700 plants, assesses the median Levelized Cost of Energy (LCOE) for French plants at approximately €130/MWh.[26]

Based on these production costs, Table 2 gives an indicative breakdown of biomethane production costs by segment.

23. “Insights into The Current Cost of Biomethane Production from Real Industry Data”, Task Force 4.2 and BIP, October 2023.

24. “Outlook for Biogas and Biomethane”, *op. cit.*

25. “EBA Policy Recommendations on the Revised CO_2 Emission Standards for Heavy-Duty Vehicles (HDVs)”, EBA, July 5, 2023.

26. “Bilan technique et économique des installations de production de biométhane injecté (hors STEP et ISDND)” [Technical and Economic Assessment of Biomethane Production Facilities for Grid Injection (excluding WWTPs and Non-Hazardous Waste Storage Facilities)], Commission de régulation de l’énergie (CRE), December 4, 2024.

Table 2: Indicative biomethane production costs by segment

Segment	Indicative cost range (€/MWh)
Large plants, best feedstocks, best locations	~45-60
"Core" current EU projects	~60-90
Small-scale or difficult feedstocks	~90-130+ (up to 175)

Source: Author from BIP, IEA, EBA and CRE.

European biomethane costs have followed a two-phase trajectory since 2010: an initial period of substantial CAPEX reductions, followed by a phase of stagnation and renewed cost pressure. While economies of scale have lowered CAPEX, particularly for larger plants, these gains have been partially offset by recent OPEX increases.

The CRE's audit shows that French plants achieved substantial CAPEX declines in the first half of the 2010s thanks to design standardization, learning-by-doing and the rollout of simpler agricultural units. CAPEX continued to fall by roughly 6% per year from 2017 to 2021, before rising sharply—by 13%—in 2022–2023 due to inflation in materials, labor and project complexity. A 14% CAPEX decrease in 2024 signals a partial correction. These gains have been offset by rising OPEX: CRE reports a 6% median increase between 2022 and 2023, driven by higher electricity prices and maintenance costs, a trend mirrored across Europe as labor, electricity and feedstock costs rose and sustainability rules tightened. Altogether, no sustained, Europe-wide cost decline has been observed since the late 2010s.

Cost reductions through innovation, economies of scale and industrialization

Cost reductions are proactively sought after by the sector. Cost reductions are achieved by adopting innovative technologies, improving energy efficiency and yields of biogas/biomethane plants, scaling up biomethane production to benefit from economies of scale, and standardizing and industrializing the sector.

Equipment suppliers are constantly innovating. Some examples are given hereunder.

- The French company Waga Energy has developed the WAGABOX® technology, an innovative solution that upgrades landfill gas to biomethane.[27] Waga Energy is now deploying its technology worldwide, with first units commissioned in Canada in 2023, the US in 2024, and now in Brazil.

27. "Upgrading Landfill Gas into Renewable Natural Gas", Waga Energy, 2026.

- The Scandinavian company, Biokraft (now St1Biokraft), has developed the HOLD Technology™, an advanced process technology to optimize large-scale biogas production.[28] Through the technology, a stable process is obtained that can handle very high loads, which in turn provides optimal production of biogas.
- The Finnish company Vaisala has developed a multipurpose instrument that can be used to improve AD yield.[29] The measurement instrument allows tracking the methane-to-carbon dioxide ratio easily and continuously to optimize the AD process. It helps to minimize the energy used to produce a given volume of biomethane and to minimize methane slip.

While every biomethane project is different, as seen previously, scale is an important driver of biomethane economics across all projects. To achieve unit cost reductions, project developers implement new business models, such as i) co-digestion of urban wastes and agriculture residues to increase the size of the projects; ii) the development of hubs/gas pooling centers, aggregating biogas and creating a centralized hub for gas clean up, upgrade to biomethane and compression prior to its injection into the gas grid (e.g., Britburg in Germany, Twente in the Netherlands, French company Sublime Energy, which offers centralized purification services, Ireland, which has developed a central injection facility with a capacity of 700 GWh/y); iii) standardization and automatization of small units to decrease their specific unit costs.

Industrialization and standardization of biogas upgrading plants also enable cost reductions. Prodeval, a leader in biogas treatment and upgrading based in France, together with Aventech and INSA Lyon, has built the first European (and global) industrial production line for biogas upgrading systems and CO_2 liquefiers.[30] The factory, located in Rovaltain (Drôme, France), opened in June 2025. The new production line aims to manufacture nearly 450 units per year, compared to the previous 150. This high production capacity and the expertise of the three partners enable the structuring and standardization of the sector across European regions and a high level of product industrialization from conception to online reconfiguration.

The costs of biomethane injected into gas networks are decreasing with economies of scale, innovation, standardization and industrialization. However, AD and biomethane upgrading technologies are mature. As such, cost reductions are not expected to be as high as for other novel technologies (e.g., solar PV). Costs are expected to decline below €70/MWh on average (with 60% of the identified potential having a lower cost) and as low as

28. "Enhance Your Gas Yield with St1 Biokraft HOLD Technology™", St1 Biokraft, 2026.
29. *Robust Science: eGuide to Biomethane/RNG Upgrading*, Vaisala, 2024.
30. "A World First in the Biogas Sector!", *Press Release,* Prodeval, March 20, 2024.

€37/MWh by 2050 for the lowest-cost projects in Europe, according to a 2021 study carried out by Engie.[31] EBA gives a range between €57 – 66/MWh for 2050, corresponding to a 20-30% reduction compared to current costs.[32]

31. "Geographical Analysis of Biomethane Potential and Costs in Europe in 2050", Engie, May 2021.
32. "EBA Policy Recommendations on the Revised CO_2 Emission Standards for Heavy-Duty Vehicles (HDVs)", *op.cit.*

From subsidy-dependent models towards market-driven solutions

Biomethane production costs remain relatively high compared to natural gas prices, except during supply crises. Despite efficiency improvements and cost reductions, biomethane average production costs are expected to remain higher than the price of natural gas, notably as the coming mega wave of LNG is expected to put strong downward pressure on natural gas prices.[33] Due to its higher cost than natural gas, national policy support has been a critical enabler of the deployment of biomethane.

Initial policy incentives have taken the form of feed-in-tariffs (FITs) or feed-in-premium (FIP), under which producers receive a guaranteed purchase tariff on a long-term basis, generally 15 to 20 years (supply-side policies). However, the cost of these policy incentives is high. For instance, in France, the FiT scheme exceeded €1 billion in 2024 and is expected to surpass € 1.2 billion in 2025.[34] To limit the fiscal burden, several European states have first moved from FIT/FIP to auction-based incentives, with the aim of enhancing competition and containing budgetary costs, while today there is a clear shift to market-based schemes.

A shift to demand-side obligations

Demand-side support schemes create demand through end-use compliance obligations associated with tradeable certificates, which add value to biomethane and help meet these new obligations. These new mechanisms are shifting the extra biomethane cost to energy providers and their consumers, instead of all taxpayers.

This shift also responds to the implementation of the RED II/III framework into national legislation (e.g., obligations on fuel suppliers in road transport). RED III also broadens the use case of biomethane to non-

33. The war in Iran has postponed the expected decline in prices as almost 20% of current global LNG supply has to travel through the Strait of Hormuz.

34. C. Lavarde (rapporteur), "Rapport relatif au projet de loi de finances pour 2025 : Écologie, développement et mobilité durables" [Report on the 2025 Budget Bill: Sustainable Ecology, Development, and Mobility], Rapport général n° 144 (2024-2025), Sénat, 2024.

transport sectors, while the EU ETS2 extends the coverage for GHG emissions in sectors not covered by the EU ETS, including buildings. In turn, several countries are implementing biomethane quotas/blending obligations for gas suppliers (Box 2).

Box 2: Blending obligations for gas suppliers

Biomethane blending obligations mandate gas suppliers either to incorporate a certain percentage of biomethane (or a certain percentage of green gases) into their natural gas supplies, or to reduce the GHG emissions of targeted energy consumers. They generally target the heating sector, which is wider than the building sector. These mandates include financial penalties for non-compliance.

These blending obligations contribute to the security of demand. They will incentivize biomethane market uptake and secure revenue streams for project developers, leading to growing production. According to E-cube, the European potential biomethane demand of the building sector is estimated at 93 TWh (around 9 bcm) by 2030.[35]

35. "A New Era for EU Biomethane: How Can We Build Confidence in Long-Term Biomethane Valuation Prospects to Support Investment Decisions, Facilitate Financing, And Enable Informed BPA Negotiations for All Parties?", E-CUBE Strategy Consultants, September 2024.

Table 3: Blending obligations for gas suppliers

Country	Schemes and Targets
France	Biomethane blending obligation: from 2026, under the **biogas production certificates (CPBs) system**, natural gas suppliers marketing more than 400 GWh/y (and all suppliers within 5 years) to the residential and commercial sector have to comply with blending mandates by submitting CPBs. In the first period (2026-2028), the rate of incorporation starts at 0.4% in 2026 (equivalent to 0.8 TWh) and rise to 1.8% in 2027 (3.1 TWh) and **4.2% in 2028 (6.5 TWh)**. A penalty of €100/CPB (or €80-110/MWh) applies for suppliers missing their targets. Only domestic production qualifies.
Netherlands	The Netherlands has adopted a **blending obligation of green gas (known as BMV**, bijmengverplichting) for gas suppliers. The proposal was amended several times. The level of the BMV now has been adjusted to **an emissions reduction along the whole chain** (including the agricultural sector). The BMW requires energy suppliers to supply a certain amount of green gas annually to EU ETS2 end-users. **The blending obligation target is 2.85 Mt CO_2 emissions reduction by 2031**. This corresponds to **0.84 bcm of biomethane in 2031**. The biomethane obligation will start in January 2027 (with a CO_2 emission reduction of 0.63 Mt, corresponding to 0.16 bcm of biomethane). The BMV requires gas suppliers to purchase **Green Gas Units (GGEs)** to meet their blending obligations. GGEs are linked to GOs, which serve as proof of renewable gas injection and consumption. The buy-out prices for energy suppliers is €450€/tCO_2.
Portugal	Decree-Law No 30-A/2022 obliges gas suppliers whose supply to final customers exceeds 2 000 GWh/y to **incorporate at least 1% of biomethane or hydrogen** produced by electrolysis from water using electricity from renewable energy sources **in 2025**. The mandatory share will be **progressively increased to at least 10 %**. The volumes of biomethane and hydrogen are auctionned. The first e-auction was opened in May 2024 (**150 GWh/y of biomethane** and 120 GWh/y of hydrogen). The base price to be paid by Transgas is €62/MWh for biomethane and €127/MWh for hydrogen. The sale of the respective GOs is also included.
Ireland	A **Renewable Heat Obligation (RHO) scheme** will be launched in 2026 and remain in place until 2045 (not yet launched as of May 2026). The RHO will obligate suppliers of fossil fuels used for heat to ensure a proportion of the energy they supply is renewable (liquid, gaseous and solid renewable fuels are included). The obligation would start with a**n initial obligation rate of 1.5%, gradually rising to 15% in 2030**. Ireland targets delivery of up to 5.7 TWh of indigenously produced biomethane by 2030. Within that overall target, Ireland also has a biomethane heating target of up to 1.1 TWh by 2030 (0.6 TWh by 2025).
Spain	**Royal Decree Law 7/2026 of April 2026 mandates annual biomethane consumption quotas** beyond transport. Gas and LNG suppliers and direct market consumers will be required to demonstrate a minimum percentage of biomethane in their natural gas sales or consumption annually (this does not apply to power generation).This process would begin in 2028 with a quota of 0.5% and reach **6% in 2035, equivalent to approximately 10 TWh.**
Germany	**A green gas quota for distributors** is expected to start in 2028, with initial levels around 1%, rising gradually over time, contributing to the reduction of GHG emissions in the building sector (new proposed Building Modernisation Act) . The proposed Act also includes a **"Bio Staircase"** requiring rising shares of renewable gases in new installed heating systems from 2029 onward, with stepped increases through 2040.

Source: Author

The policy shift towards demand-side incentives has led to a segmentation of the European market, with two main market models that allow producers to be compensated for the additional production cost.

- Voluntary markets (subsidized) – where the MS offers production subsidies to operating facilities. In many countries where subsidies are offered, production volumes can still receive GOs to be used for renewable energy disclosure by end-users, which can bring additional revenue to sellers (but are generally excluded from compliance usage).
- Compliance markets (unsubsidized) – where the biomethane is sold to markets willing to pay a premium for the green attributes. These markets are usually associated with obligation schemes (e.g.,

biofuels in the transport sector, blending obligations), where there are high financial penalties for non-compliance (e.g., €600/tCO_2eq in the German GHG quota system). Compliance markets rely on the extra revenue generated from certificates (GOs and PoSs).

Towards a merchant biomethane market

In addition, the recognition of biomethane in the EU ETS fosters the emergence of a consumer-driven model, based on BPAs. In the EU ETS, provided that it fulfills the sustainability and GHG emission savings requirements of the RED, biomethane is given an emission factor of zero, thus avoiding the purchase of emission allowances. Reducing emissions is a key driver for the use of biomethane as a substitute for natural gas for corporations subject to extensive sustainability reporting. The EU Taxonomy and the Corporate Sustainability Reporting Directive (CSRD) form the legal framework for large European companies, some of which are obliged to report in detail on the sustainability of their business operations.

These BPAs, which lock in price and volume over extended periods, are mainly signed by industrial companies in hard-to-abate sectors that are pursuing ambitious CO_2 reduction targets and are subject to extensive sustainability reporting. The use of biomethane is a key lever to meet their GHG mitigation targets by 2030, as it ensures a fast, cost-competitive and predictable reduction in operational emissions. Also, several industries developing hydrogen or Renewable Fuels of Non-Biological Origin (RFNBO) projects see the prospects being delayed or reduced. But their GHG targets have to be met. Thus, biomethane is a natural fuel choice. A prominent example of BPA in the industrial sector is the seven-year agreement between BASF and Engie, under which Engie will supply BASF with up to 3 TWh of biomethane to replace fossil feedstocks at its chemical sites in Germany and Belgium.[36] More recently, Engie has announced a 10-year BPA with PepsiCo UK, the first of its kind for the UK food and drink industry.[37] Under the agreement, which begins in 2027, 60 GWh/y of biomethane will be produced from a new plant to help decarbonize PepsiCo UK's supply chain.

These BPAs are also signed by energy suppliers engaged in the decarbonization of their gas supplies. A landmark example is the 13-year contract signed by Engie with Waga Energy.[38] This agreement enables Engie to market unsubsidized biomethane to its customers.

36. "BASF and Engie Sign Long-Term Biomethane Supply Agreement in Europe", BASF, July 4, 2024.
37. "Engie Signs Landmark 10-Year Biomethane Purchase Agreement With Pepsico Its First In The United Kingdom", Engie, January 21, 2026.
38. "Waga Energy Signs First Long-Term Private Biomethane Purchase Agreement (BPA) in France", WAGA Energy, May 29, 2024.

Table 3: Recent examples of BPAs signed by large corporations and industrial companies

Supplier	Buyer	Total quantity (GWh)	Annual quantity (GWh/year)	Contract duration (years)	Start of delivery
Waga Energy (Claye-Souilly, FR)	ENGIE (FR)	1560	120	13	2024
Future Biogas (Moor Bioenergy, GB)	AstraZeneca (GB)	1500	100	15	2025
CVE Biogaz (Ludres, FR)	ENGIE (FR)	465	31	15	2027
TotalEnergies (BioBéarn, FR)	Saint-Gobain (FR)	100	33	3	2024
ENGIE (FR)	Arkema (FR)	3000	300	10	2023
ENGIE (FR)	BASF (DE)	2700-3000	400	7	2024
ENGIE (FR)	Arkema (FR)	200	25	8	2025
ENGIE (FR)	PepsiCo UK (GB)	600	60	10	2027
Five Bioenergy (ES)	Uniper (DE)	not disclosed		7	2027

Source: Author, updated from Oxford Institute for Energy Studies. [39]

These BPAs complement traditional policy support by providing developers with the certainty required to secure financing. Under the unsubsidized BPA model, the production cost gap between biomethane and natural gas is covered by the off-takers making long-term off-take commitments. For off-takers, BPAs ensure reliable delivery of renewable energy within a bundled structure that typically includes the biomethane commodity and its environmental value (GOs and PoSs). These sectors rely on mass-balance certified biomethane (PoS), using ISCC/REDcert mass-balance certification, to be compliant with RED sustainability requirements.

These BPAs initiate a merchant biomethane market, enabling the development of production without government subsidies. They signal biomethane's increasing commercial maturity and integration into core industrial sectors. However, the regulations on the use of biomethane certificates have not yet been sufficiently clarified, meaning that biomethane use remains subject to certain uncertainties. The Greenhouse Gas Protocol (GHG Protocol) plays a pivotal role in shaping the voluntary market for biomethane certificates. Institutions, such as the Science Based Targets initiative (SBTi),[40] follow guidance from the GHG Protocol to determine their accounting standards for GHG emissions. However, current guidance under the GHG Protocol leaves the role of biomethane

39. M. Olczak, "Biomethane in Europe: Why Scaling Up is Harder than It Looks", Oxford Institute for Energy Studies, January 2026.
40. The SBTi's Corporate Net-Zero Standard is the world's only framework for corporate net-zero target setting in line with climate science. It includes the guidance, criteria, and recommendations companies need to set science-based net-zero targets consistent with limiting global temperature rise to 1.5°C.

certificates ambiguous.[41] The ongoing revision of the GHG Protocol offers a critical opportunity to clarify guidance for biomethane certificates and facilitate their use in voluntary markets.[42]

41. S. Huckins, "Interim Update on Accounting for Biomethane Certificates," Greenhouse Gas (GHG) Protocol, August 21, 2023; S. Huckins, "2024 Reflections and Looking Ahead: Letter from the GHG Protocol Steering Committee Chair and Vice Chair", GHG Protocol, January 16, 2025.
42. "Let Green Gas Count Campaign Coalition Issues High-Level Recommendations Towards Corporate Greenhouse Gas Reporting", EBA, September 5, 2025.

Valorizing biomethane benefits beyond energy

Despite its higher cost than natural gas, producing biomethane results in positive externalities that go beyond the provision of renewable gas. When these externalities are taken into account, the value of biomethane becomes much more attractive than natural gas. EBA has assessed the value of these positive externalities.[43] Using the biomethane potentials for 2030 and 2050, EBA estimates the whole-system benefits of biomethane production in the EU27 + UK in a range of €38-78 billion per year in 2030, rising to €133-283 billion by 2050. AD delivers externalities with a value of €84-175/MWh of biomethane produced, while thermal gasification delivers externalities with a value of €80-162/MWh.

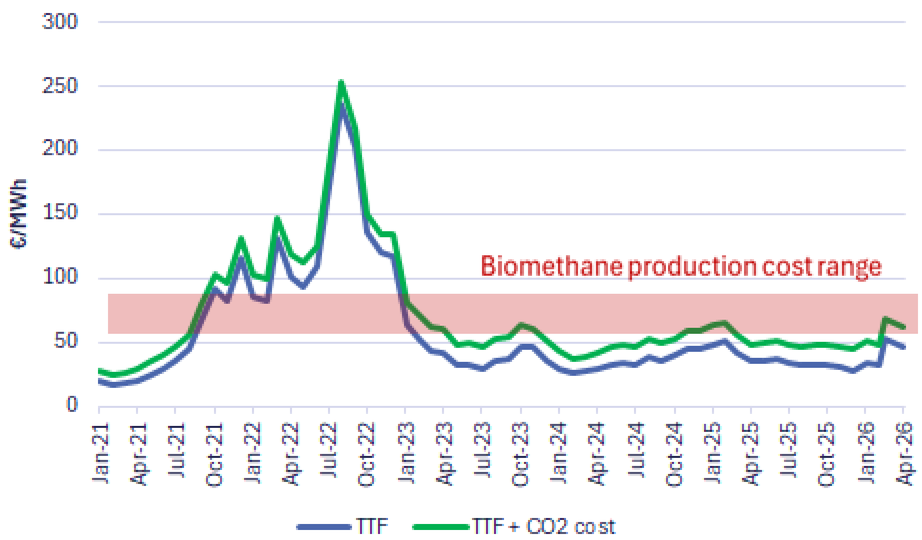
Job creation, the reduction of GHG emissions, the provision of biogenic CO_2, energy security and waste processing are key value drivers. Except for waste management services, which already receive economic compensation (through gate fees), other externalities are difficult to monetize. However, recent market and policy trends show a clear trend towards the valorization of the environmental value of biomethane, through the sale and trading of biomethane certificates, as well as the use of biomethane production byproducts, biogenic CO_2 and digestate.

Valuing and trading the environmental value of biomethane

One key benefit of biomethane production is the reduction of GHG emissions, both CO_2 and methane emissions, across economic sectors. If carbon prices are applied to the combustion of natural gas, then biomethane is a more attractive proposition and can even become cheaper than natural gas. In 2022, when European natural gas prices rose to extreme levels, biomethane production costs were temporarily lower than the natural gas spot price (Graph 3). Moreover, when the price of carbon that large industrial companies and power plants have to pay under the EU ETS was added, the competitiveness of biomethane was even higher.

43. "Beyond Energy – Monetising Biomethane's Whole-System Benefits", EBA, February 14, 2023.

Graph 3: Production cost of biomethane vs. Natural gas prices



Note: CO_2 cost based on natural gas emissions of 0.202 tCO_2/MWh (56 gCO_2/MJ).

Source: Author, BIP (cost range).

Since then, natural gas prices have declined, reversing the competitive advantage of biomethane vs. natural gas. However, Graph 3 shows that with the price of CO_2 on the EU ETS over the past 3 years (around €74/t CO_2 on average), biomethane production from large plants in Europe has been cost-competitive with natural gas, even without considering additional subsidies or value added from digestate or biogenic CO_2 sales. Again, in March, April and May 2026, natural gas prices surged, raising the competitiveness of biomethane.

As the expansion of biomethane capacity increasingly relies on unsubsidized sales, biomethane certificates are becoming essential for biomethane producers to secure revenues and grow volumes. According to a recent analysis by S&P Global Commodity Insights, in four selected countries (Denmark, Germany, the Netherlands, and the UK), the sale of GOs could cover 36-58% of typical biomethane production cost in 2023.[44]

Biomethane certificate prices vary considerably, depending on their purpose (compliance vs. voluntary markets). In voluntary markets (subsidized biomethane), production volumes can still receive GOs to be used for renewable energy disclosure by end-users, but the price of GOs is generally low (around €10/MWh), insufficient to cover alone the additional cost of producing biomethane. In compliance markets, the price of certificates varies from country to country, depending on many factors, such as feedstock used to produce biomethane, end-use destination, competition from alternative biofuels and technologies in the transport sector (as

44. "First Comprehensive Report on The Trading Of Biomethane Certificates Confirms Solid Tracking Systems Are in Place And Working in EU And USA", EBA, October 24, 2024, based on analysis by S&P Global Commodity Insights.

biomethane is one option among several clean fuels and technologies), supply/demand balance and legal decisions regarding credit factors, etc. Leading publishers (Platts, Argus) publish price assessments for European biomethane GOs, enabling price transparency.

As seen previously, a key driver of biomethane certificates prices is the CI of biomethane. Certificate values for biomethane derived from animal manure feedstock attract a premium in markets that recognize the highest GHG emission savings (i.e., negative CI values under RED for transport, FuelEU Maritime). In that case, the sale of certificates can even be above the full lifecycle cost of biomethane production. For instance, in Germany, the average price of the GHG quota in the transport sector averaged €239/tCO_2eq in 2023. At this level and adding the price of TTF in 2023 (€41/MWh), the price of biomethane produced from animal manure substrate equated to €202/MWh, substantially above the full lifecycle cost of biomethane production.

Biomethane certificate prices have been volatile over recent years. Fraud in trading German GHG quotas in the transport sector in 2023 led to a drastic drop in prices, making biomethane uneconomical. The price of the GHG quota fell from more than €400/tCO_2eq at the end of 2022 to €120/tCO_2eq at the end of 2023. A surge of fraudulent “advanced” biodiesel imports from China destabilized the GHG quota system. The drop also influenced the price of certificates in other European countries. German prices fell again in 2024 on the back of weak demand and oversupply. They remained volatile in 2025, based less on fundamentals and more on political signals and expectations on the way the German government would transpose RED III into national legislation. The German price surged from June 19, 2025, when Germany published the RED III draft. In early January 2026, it rose above €500/tCO_2eq. The price is close to the penalty for GHG quota non-compliance (€600/tCO_2eq).

The reform of the German GHG quota system, which entered into force at the beginning of 2026—ending double counting, tightening sustainability rules, suspending quota transfer for 2025-2026, raising GHG reduction targets with a 65% emission reduction target set for 2040, and restricting imports—has shifted the market towards higher and more credible price levels, restoring the GHG quota as a meaningful driver of renewable fuel deployment, including biomethane.

Valorizing biogenic CO_2

Biogas upgrading results in a highly concentrated stream of biogenic CO_2. A growing trend seen in recent years is the installation of CO_2 capture equipment on site and the use of the biogenic CO_2 (CCU) or its permanent storage underground (BECCS). Depending on the size of production and the

CO_2 concentration in the gas stream, the cost of capture can be €25-90/tCO_2, equivalent to €3-12/MWh biomethane.[45]

The biogenic CO_2, which substitutes fossil CO_2, has many industrial applications, for example, in greenhouses, in the pharmaceutical, chemicals and food and beverage industries and increasingly as an input for low-emissions fuels production (or e-fuels). The sale of the biogenic CO_2 creates additional revenue streams for producers, while the future CO_2 market opens opportunities for the biogases sector. The price of industrial-grade CO_2 in Europe currently trades around €0.25–€0.35 per kg (0.29 in February 2026).[46]

According to EBA, the number of biomethane plants capturing biogenic CO_2 in Europe has increased eightfold over the past five years, from 15 plants capturing 0.16 Mt in 2020 to 125 plants capturing 1.17 Mt in 2025, equivalent to around 14% of Europe's merchant CO_2 demand. The UK leads the way in the capture of biogenic carbon, accounting for 22% of the total currently captured volume. It is followed by Germany (15%), Denmark (14%), France (14%), the Netherlands (12%) and Italy (12%).

Up to now, the EU ETS does not recognize or include carbon removal (CDR)—such as those from BECCS—as a compliance instrument, meaning that companies cannot use negative emissions to offset their obligations under the system. A February 2026 revision to the EU ETS (not yet adopted at the time of writing) redefines compliance pathways and includes the possibility to use certified carbon credits, including those based on biogenic CO_2 capture with carbon storage, to offset ETS obligations.[47]

Valorizing digestate as biofertilizer

Another trend is the commercialization of digestate as biofertilizer, in replacement or complement of synthetic fertilizers. In addition to essential nutrients such as nitrogen, phosphorus, and potassium, biofertilizer possesses soil-improving properties.[48] Its nutrient content and structures contribute to enhanced plant growth and moisture retention. Biofertilizer thus increases crop yield, minimizes nutrient pollution, and makes agriculture and food production more sustainable and resilient.

According to EBA, 26 Mt dry matter (DM) of digestate was produced in Europe in 2024. The volume of digestate is set to grow significantly in the coming years in line with the expected scale-up of the biomethane sector.

45. "Biogenic CO_2: The Role of The Biomethane Industry in Satisfying A Growing Demand", Task Force 4.1 and BIP, April 2024.
46. "Carbon Dioxide Price Index", BusinessAnalytiq, 2026.
47. "EU Sets World's First Voluntary Standard for Permanent Carbon Removals", Directorate-General for Climate Action of the European Commission, February 3, 2026.
48."Exploring Digestate's Contribution to Healthy Soils", EBA, March 2024.

Depending on the feedstock, digestate can be used directly as fertilizer or may require processing before use. Also, in certain regions of Europe, there is an excess of nutrients, such as nitrogen or phosphorus.[49] In these regions, not all digestate can be applied locally. Instead, several companies have successfully developed processes to transform local digestate into added-value exportable products.

By replacing synthetic fertilizers, digestate also contributes to energy security and helps mitigate the effects of climate change. Biofertilizer reduces the agricultural reliance on imported synthetic fertilizers, and with long-term delivery contracts, farmers can secure access to biofertilizer at stable prices unaffected by volatile global market prices, as the EU imports more than a third of its total fertilizer consumption.

Legislation remains a key driver for nutrient recovery adoption; application rates must comply with national and EU guidelines to minimize environmental risks. If regulatory frameworks keep pace with technological advances, ensuring quality standards and safety, a broader adoption of digestate as a renewable fertilizer can be expected. Several MS have already implemented national quality assurance schemes to ensure that operators comply with quality standards for digestate and enhance the beneficial effect of its application to the soil, which could otherwise be reduced by poor or improper management.

The Clean Industrial Deal highlights the importance of sustainable biofertilizer production in meeting circularity and security goals, providing a spur to valorizing digestate. So does the EC Fertilizer Action Plan from May 2026.

49. "Use and Valorisation of Digestates from Biomethane Production: A Practical Review", Task Force 2 and BIP, December 2025.

What role for biomethane in the energy transition?

Criteria for prioritizing biomethane uses

Biomethane is positioned as a key, strategic energy carrier in Europe's transition towards a low-carbon, resilient, and secure energy system. Because it is compatible with existing gas infrastructure, biomethane can replace natural gas immediately in multiple sectors. Biomethane's versatility enables its use across industry, power generation, transport, and building. However, limited resources compared with natural gas and competition for sustainable biomass require biomethane use to be prioritized in applications where it offers the highest system value with the greatest emission reductions, and where no other decarbonization options (electrification, clean hydrogen, e-fuels, Carbon Capture, Utilisation and Storage (CCUS)) can deliver the same combination of GHG-reductions, circularity, and system services. The "energy efficiency first" principle does indeed apply initially.

Prioritizing uses must be based on explicit criteria.

An explicit criterion is the marginal abatement cost (MAC) of a given specific biomethane application relative to a fossil comparator and other decarbonization options. The MAC assesses the cost of the technology per ton of CO_2 avoided. System value (flexibility, peak-shaving, firm heat) must also be taken into account. It captures the contribution of biomethane, as a flexible, dispatchable, storable molecule, to keeping the energy system reliable, resilient, and operable in ways that other low-carbon options cannot easily replace. Circularity refers to the unique position of biomethane in some applications where it adds a circular economy benefit (use of produced residues and byproducts).

More specifically, for each potential application of biomethane, biomethane must be compared to alternative technologies, according to the decarbonizing capacity of the solution, its level of maturity, its cost and other characteristics, such as technological lock-ins or path dependencies (need for specific equipment/infrastructure), externalities and acceptability.

Biomethane uses that do not currently benefit from a decarbonization alternative, or for which such an alternative will not be available within a reasonable timeframe, must be prioritized. Finally, analyzing the orders of magnitude of biomethane demand for a given application verifies whether the allocation is consistent with the biomethane potential.

These analyses are rarely carried out at the national level due to their complexity. However, there are some useful examples, such as the UK,[50] France, for biomass,[51] and Germany for competition between hydrogen and biogas.[52] Nevertheless, analyses at the European level (e.g., IEA,[53] Common Futures,[54] and EBA/ BIOMETHAVERSE[55]) provide valuable assessments of end-use applications for which biomethane is the optimal decarbonization solution.

Industry

Natural gas consumption by the EU industrial sector amounted to around 100 bcm in 2024, accounting for 31% of EU gas consumption. The chemical industry is the largest industrial gas consumer, currently consuming 40-45 bcm per year. This is made up of around 30% for energy purposes and 70% used as feedstock. Among the other subsectors of EU industry, the highest natural gas consumption is from non-metallic minerals (e.g., glass and ceramics), iron and steel, fertilizer and the food industry.

A systematic approach to abatement costs is necessary to rank these industrial uses. Some examples are given hereunder.

High-temperature industrial heat processes

Although electrification can contribute to the decarbonization of several industrial applications requiring low- and medium-temperature heat, several key sectors, including glass, ceramics, and chemical processes, require high-temperature heat (500-2000°C), which is currently provided by burning natural gas. Electrification of high-temperature processes is possible but can be challenging, mainly due to higher costs relative to fossil-fueled processes (except in times of gas price crises), and in some cases, there are also technical issues to overcome. Biomethane, clean hydrogen, e-fuels, and CCUS are the alternative decarbonization options for these industrial processes. Until recently, most large industries focused on renewable hydrogen as part of their strategies to reach net-zero emissions. However, since hydrogen and its derivatives have proven to be initially more expensive,

50. "Making the Most of Biomethane: An Examination of Biomethane's Role in the Energy Transition", Regen and MCS Foundation, September 29, 2025; "Biomethane: Reducing the Cost of Net Zero", Cadent and Green Gas Taskforce, October 9, 2025.
51. "Quelles contributions attendre de la biomasse dans la transition énergétique ?" [What role can biomass play in the energy transition?], Académie des technologies and Académie d'agriculture de France, May 2025.
52. "Zukunftsaussichten der Biogasbranche" [The Future Outlook for the Biogas Industry], Institüt für ZukunftsEnergie-und Stoffstromsysteme (IZES) and Fachverband Biogas e.V., September 2025.
53. "Outlook for Biogas and Biomethane", *op. cit.*
54. "Biomethane for Emission Abatement by 2040: Using Biomethane to Reach Net-Zero Emissions in Primary Steel And Dispatchable Power", Common Futures, April 2024.
55. "D4.1 – Scenarios and Vision for Market Penetration", BIOMETHAVERSE Project, Agreement No. 101084200, June 2024.

and large-scale deployment has been delayed until 2035, biomethane has emerged as a viable solution for high-temperature industrial processes today.

Biomethane is a cost-effective, drop-in, low-CI fuel that can replace natural gas in burners, kilns, and furnaces, allowing decarbonization without the need to redesign process equipment. Table 4 provides examples of BPAs signed by industries in these hard-to-abate sectors.

Even in some specific low- and medium-temperature industrial heat processes, biomethane can be the optimal option (e.g., the food and beverage sector, the pulp and paper industry), as it adds a circular economy benefit (use of produced residues and byproducts).

Biomethane has the additional benefit that it can be used in processes that require carbon as an input, including petrochemicals and steelmaking.

Use as feedstock in the chemical and fertilizer industries

Decarbonizing the chemical industry requires a portfolio of complementary strategies that address energy use, feedstock carbon, and process-related emissions. No single technology can achieve full abatement. Rather, a coordinated deployment of drop-in fuels (e.g., biomethane), process transformations (e.g., electrification and hydrogen), and carbon management solutions (e.g., carbon capture and storage (CCS), circularity, and negative emissions) is necessary. While hydrogen and electrification represent structural, long-term shifts, CCS can be an important technology for bending the overall industry emissions curve, depending on its availability and scalability. The latter depends heavily on the circumstances of each country. Decarbonized feedstocks (e.g., biomass, plastic waste, and CO_2) can serve as sources of the carbon needed for primary chemical building blocks, intermediate chemicals, and ultimately, consumer products.

Among this portfolio, biomethane is the fastest-deployable lever today. As a substitute for natural gas, it does not require equipment modification and provides immediate GHG emissions reductions and a renewable carbon feedstock. Its production yields biogenic CO_2 streams suitable for carbon management pathways, including negative emissions when paired with CCS. The EU's chemical industry consumes 40–45 bcm of natural gas per year for energy and feedstock. While biomethane cannot replace all natural gas, it can decarbonize priority segments.

In the fertilizer industry, a recent analysis shows that the EU ammonia production can achieve cradle-to-gate net-zero GHG emission using, on average, a blend of natural gas (56%) and biomethane (44%) combined with CCS.[56] This strategy would require only 12% (4.5 bcm/y) of the

56. R. Istrate *et al.*, "One-Tenth of The EU's Sustainable Biomethane Coupled with Carbon Capture And Storage Can Enable Net-Zero Ammonia Production", *One Earth*, Vol. 7, No. 12, 2024, pp. 2235-2249.

2030 EU sustainable biomethane potential and is at least 16% cheaper than the renewable hydrogen option. Moreover, the analysis shows that cradle-to-gate negative GHG emissions can be attained by completely switching to biomethane coupled with CCS.

In Germany, according to the Institute for Future Energy and Material Flow Systems (IZES), demand for natural gas as feedstock in the chemical industry—especially basic chemicals—could be fully substituted by biomethane by the end of the 2020s, considering the total and infrastructural biomethane potentials identified by IZES.[57]

In the UK, using biomethane in the chemical industry is not considered high-value compared to some other high-temperature industrial processes, such as glass and ceramics production.[58] Instead, the UK is deploying CCUS technologies to decarbonize regional industrial clusters where emissions from the refining, chemical, iron, and steel sectors are concentrated.[59] The captured CO_2 is then used in chemical processes or stored permanently.

Use in the steel industry

In the steel industry, biomethane can provide high-temperature heat and carbon-rich feedstock in the production of direct reduced iron (DRI) paired with producing steel in electric arc furnaces (EAFs). This technology no longer uses coal but gaseous fuels natural gas, biomethane or hydrogen), today mostly natural gas.

According to analyses by Common Futures, using biomethane results in the lowest overall abatement costs.[60] This is particularly true when negative emissions are created by combining biomethane with CCS. The analysis shows that biomethane combined with CCS is not only the most cost-effective option for achieving net-zero emissions steel production, but also achieves climate-positive steel. Additionally, a pure stream or blend of biomethane provides DRI processes with feedstock flexibility pending the availability of large-scale, renewable hydrogen. Common Futures assumes that 15 bcm of biomethane will be available to steel producers by 2040. This would produce 48 Mt of green steel. However, Common Futures estimates that the total EU production will be 68 Mt, meaning that 20 Mt will need to be produced through another decarbonization pathway, such as hydrogen.

57. "Zukunftsaussichten der Biogasbranche", *op. cit.*
58. "Making the Most of Biomethane: An Examination of Biomethane's Role in the Energy Transition", *op. cit.*
59. "Enabling Net Zero Progress: Deploying CCS to Decarbonise UK Industrial Clusters", Innovate UK and UK Research and Innovation, October 2024.
60. "Biomethane for Emission Abatement by 2040", *op. cit.*

Power

Flexible power generation to balance variable renewables

According to the IEA, the levelized cost of generating electricity from biomethane is around 50% higher than for onshore wind and solar photovoltaic generation (in a range of USD 95/MWh to USD 160/MWh).[61] These intermittent sources, however, need to be complemented by energy storage and dispatchable and baseload sources to match demand and supply during the year, especially during periods with low availability of sunlight or wind and periods with peaks in demand. The need for flexible and dispatchable power generation positions biomethane as a renewable balancing asset in electricity systems. Biomethane provides renewable, dispatchable power. It solves wind and solar variability, low-renewable periods, and the need for dispatchable, fast-ramping power.

Common Futures' analyses show that existing hydropower and nuclear power plants, followed by biomethane, offer the most cost-effective options for dispatchable electricity generation.[62] Biomethane is more cost-efficient than renewable hydrogen, even without taking into account the biomethane abatement costs reductions from applying options for negative emissions. Common Futures assumes that 20 bcm of biomethane will be available for EU dispatchable power production by 2040.

For seasonal flexibility (e.g., winter-peaking capacity), gas-fired power plants are still one of the few readily available options. The use of biomethane enables this role to be performed with lower emissions than using natural gas. Data from the IEA show that the levelized cost of electricity of power plants fired by natural gas is around 15-70% lower than that of biomethane, but a CO_2 price of USD 50/t CO_2 would reduce this gap to 0-50%. Biomethane is also the most cost-effective option compared to other low-carbon fuel blends due to compatibility with existing infrastructure, reducing the need for retrofit. This is a key advantage over hydrogen, which requires coordinated development of new generation infrastructure, transport infrastructure and electrolysis production.

In the UK, the University of Cambridge Energy Policy Research Group also demonstrates how biomethane is the most cost-effective option compared to other low-carbon fuel blends (green hydrogen, green ammonia) for converting combined-cycle gas turbines (CCGTs) to low-carbon fuels, due to compatibility with existing infrastructure, reducing the need for retrofit.[63]

61. "Outlook for Biogas and Biomethane", *op. cit.*
62. "Biomethane for Emission Abatement by 2040", *op. cit.*
63. A. Abuzayed *et al.*, "Exploring the Feasibility of Low-Carbon Fuel Blends in CCGTs for Deep Decarbonization of Power Systems", *Energy Strategy Reviews*, Vol. 63, January 2026.

IZES shows that biogas can replace natural gas in Germany's electricity, heating, and hydrogen sectors to a significantly greater extent than previously assumed, as early as the mid-2030s. This can be achieved through flexible, on-site power generation and upgrading to biomethane.[64] These findings call into question the need for large-scale construction of new H2-ready gas-fired power plants.

Transport

Road transport: decarbonization of heavy-duty vehicles (HDVs)

Road transport is a core market for biomethane use. The transposition of RED II/III into national legislation drives the use of advanced biomethane in EU road transport. In addition, from 2028, the EU ETS2 will extend to road transport with biomethane qualifying for zero-rated treatment if it meets RED II/ III sustainability criteria.

While the adoption of biomethane in light vehicles is declining, the HDV segment is experiencing rapid growth. In Germany, for instance, the use of biomethane in the transport sector reached 3.9 TWh in 2025, up from 0.9 TWh in 2020, boosted by sales of bio-LNG.[65] Large companies like DHL Group and Amazon have adopted bio-CNG/bio-LNG on a massive scale.

The EU HDV segment counted around 6 million trucks in 2024, largely diesel-fueled (96%), while electrification accounted for a tiny share (0.3%) and natural gas vehicles (NGVs) for 0.8%.[66] Diesel maintained its leading position in 2025, accounting for most of the new registrations (93%), while electrically-chargeable trucks secured 4.2% of the new registrations.

The slow uptake of zero-emission vehicles (ZEVs), such as battery electric vehicles (BEVs), fuel cell electric vehicles (FCEVs), makes it difficult to achieve the EU GHG emissions reduction targets for HDVs of 45% by 2030 and 90% by 2040.[67] Meeting the 2030 CO_2-targets requires ~400,000 ZEVs in operation in 2030 (26,000 in 2024) and ~50,000 publicly accessible charging points suitable for HDVs (~1000 in 2024).[68] The main barriers that zero-emission HDV adoption is facing include Total Cost of Ownership (TCO), lack of electricity grid capacity and the length of related

64. "Zukunftsaussichten der Biogasbranche", *op. cit.*
65. "Time Series for The Development of Renewable Energy Sources in Germany: Based on Statistical Data from The Working Group on Renewable Energy-Statistics (AGEE-Stat)", German Federal Ministry for Economic Affairs and Climate Action, February 2025.
66. "Vehicles on European Roads 2026", European Automobile Manufacturers' Association (ACEA), January 2026.
67. Regulation 2019/1242 on CO2 emission standards for HDVs, and the amending Regulation (EU) 2024/1610, adopted in 2024, which set increasingly strict emission standards for new trucks, buses and coaches.
68. "Decarbonising Heavy-Duty Road Transport: State of the Enabling Conditions", ACEA, October 2025.

administrative processes, lack of public recharging, and green hydrogen price uncertainty and availability.[69]

To meet the EU GHG emissions reduction targets for HDVs, together with electrification, switching to bio-CNG and bio-LNG provides an already operational, scalable, and readily available solution, capable of immediately reducing emissions of HDVs. Bio-CNG delivers lifecycle emissions reductions of approximately 90% compared to diesel, while manure-based biomethane can create net-negative emissions, meaning that at a system level, trucks running on biomethane are not increasing CO_2 emissions, but instead reducing them. Currently, biomethane represents around 40% of all gas used in European NGVs. This enables a reduction of CO_2 emissions of 55% compared to diesel.

The infrastructure to distribute bio-CNG/bio-LNG is already well developed, with around 4200 CNG stations and around 800 LNG stations at the end of 2025; and there are approximately 1,900 bio-CNG and 123 bio-LNG filling stations operational throughout Europe.[70] CNG and LNG vehicles are based on mature technology. In 2024, there were some 50,000 gas-powered trucks in the EU. France, Spain and Italy are the leading countries. In addition, biomethane outperforms electrification in operational flexibility for long-haul HDVs because BEV trucks face range, charging time, and payload penalties, while biomethane trucks match diesel-like range and payload today. Looking at the longer run, EBA estimates that 15 bcm of biomethane would be sufficient to power approximately 20% of the EU's HDV fleet in 2050.[71]

However, instead of promoting low-emission alternatives such as bio-CNG/bio-LNG in long-haul HDVs, the EU regulation on CO_2 limits for HDVs compromises the use of biomethane in the segment. The regulation is not technology-neutral as it considers tailpipe emissions only (Tank-to-Wheel approach) and does not include recognition of renewable combustion fuels.

After years of strict ZEV policy and regulatory incoherence, the EC Automotive Package, launched in December 2025, recognizes the need for pragmatic, near-term decarbonization of the road transport sector.[72] However, the package makes a significant distinction between light vehicles and HDVs. For light vehicles (cars and vans), the Automotive Package leaves room for light internal combustion engine (ICE) vehicles after 2035, marking a significant shift from the previous policy. From 2035 onwards, carmakers will need to comply with a 90% tailpipe emissions reduction target (instead of 100% previously), while the remaining 10% emissions will need to be

69. "Market Readiness Analysis: Expected Uptake of Alternative Fuel Heavy-Duty Vehicles Until 2030 And Their Corresponding Infrastructure Needs", Directorate-General for Mobility and Transport of the European Commission, 2025.

70. EBA Policy Recommendations on the Revised CO_2 Emission Standards for Heavy-Duty Vehicles (HDVs)", *op. cit.*

71. *Ibid.*

72. "Automotive Package", European Commission, December 2025.

compensated through the use of biofuels, e-fuels and low-carbon steel made in the Union. For HDV, the package proposed a targeted amendment to the CO_2 emission standards, aiming to provide manufacturers with additional flexibility to ease compliance with their 2030 CO_2 emissions targets. This targeted amendment was adopted in March 2026.

But despite scientific evidence, the regulation for HDVs keeps a tailpipe approach, which treats biomethane as a fossil fuel, instead of a CO_2-neutral or even negative fuel. Stakeholders from the biomethane sector have reiterated their call for a technology-neutral approach that considers the benefits of all green solutions (e.g., by introducing a definition of CO_2-neutral fuels and a Carbon Correction Factor capable of fully recognizing biomethane as a renewable solution, and by implementing a technology-neutral lifecycle approach). A review phase of the regulation is foreseen for 2027. In this context, it should be stressed that delays in adopting a technology-neutral approach risk slowing down urgent decision-making and weakening existing supply chains, rather than fostering innovation. Only a coherent, technologically inclusive, and reality-based policy can help achieve European and national climate goals, especially in the long-haul HDV segment that is more difficult to electrify.

In the other road transport segments (such as passenger cars), electrification of the fleet is progressing, although more slowly than expected. Electrically-chargeable cars made up 8.7% of the fleet in 2024. The Automotive Package will make biomethane more attractive in this segment, as biomethane is among the compliance mechanisms enabling manufacturers to compensate emissions post-2035. In addition, RED III and some national policies push biomethane in this segment. For instance, in Italy, policy measures (e.g., the biomethane Ministerial Decree of 2018) have been designed to ensure the adoption of biomethane by the around 1 million CNG passenger cars operating in the country.

Maritime sector

In the maritime sector, there is a growing demand for alternative maritime fuels to reduce the environmental impact of maritime transport and comply with new regulations. The extension of the EU ETS to shipping from 2024, the entry into force of the FuelEU Maritime regulation on January 1st,2025 (see Table 1), and potential future International Maritime Organization (IMO) decarbonization regulations[73] are strong drivers for shipowners to adopt renewable and low-carbon fuels and alternative propulsion technologies.

73. In its "2023 IMO GHG Strategy", the IMO has set a reduction target for GHG emissions of 40% compared to 2008. However, IMO decided in October 2025 to delay the adoption of the Net Zero Framework.

To decarbonize their fleets, shipowners are investing in new vessels with engines that can run on alternative fuels (LNG, LPG, methanol, hydrogen or ammonia). The LNG pathway (LNG, bio-LNG and in the future e-LNG) has emerged as the preferred pathway for decarbonization when it comes to the alternatively fueled newbuild orderbook. LNG-powered vessels ordered in 2025 accounted for 79% of alternative-fueled tonnage.[74] The number of LNG-fueled ships in operation reached 850 at the end of 2025 (excluding LNG carriers), with a further 642 on order. Overall, the LNG-powered global fleet, both operating and on order, including LNG carriers, now represents 10% of the global fleet by deadweight tonnage. The infrastructure is also growing. LNG bunkering is now offered in 222 ports globally. The number of bunkering vessels reached 62 in 2025, with an order book of 38. The global LNG bunkering demand is also on a steep upward trend. It reached an estimated 3.8 Mt in 2025, up 46% year-on-year.

Analysis by SEA-LNG shows that the LNG pathway offers the lowest cost of compliance with EU and potential future IMO decarbonization regulations compared with other alternative marine fuel solutions available today.[75] LNG offers GHG emission reductions of up to 23% compared with marine diesel, whereas other alternative marine fuels, such as ammonia and methanol, have higher emissions. Bio-LNG is one of the few renewable fuels that can be deployed immediately at scale, whereas e-fuels are not expected to be a credible alternative before 2035. Bio-LNG can deliver 70–190% GHG reductions versus marine diesel, depending on feedstock. Biomethane, especially from manure, can achieve negative emissions (around -100 grams CO_2eq/MJ). While the EU ETS accounts for zero emissions for bio-LNG by default, negative emissions are recognized under the FuelEU Maritime regulation. This makes low-CI bio-LNG an attractive fuel with which shipping companies can significantly exceed their emission reduction targets.

Bio-LNG demand has surged since the entry into force of the FuelEU Maritime regulations. Although data for 2025 is not yet available, market information indicates that the number of bio-LNG bunkering contracts between producers/traders and fleet owners has increased significantly, especially in the Rotterdam area and the Nordic countries. A landmark deal saw Swedish tanker operator Furetank secure sufficient bio-LNG from commodity trader Cargill and fuel supplier Titan Clean Fuels to fuel its entire European fleet in 2025.[76]

74. "The Journey: A Decade Moving Towards A Cleaner Future – View from the Bridge 2025-2026", SEA-LNG, January 20, 2026.

75. *Ibid.*

76. "Furetank Switches EU Fleet to Renewable Biogas Under Landmark Deal", *Bioenergy Insight Magazine*, August 29, 2025.

In the longer term, 14 bcm of bio-LNG would cover 20% of the anticipated LNG demand in the shipping sector in 2050, according to SEA-LNG.

Building

Today, the building sector is the largest user of natural gas in the EU (113 bcm in 2024). Natural gas is also the largest energy source in the EU residential sector, accounting for 31% of final energy consumption, with over 40% of households connected to gas networks and 68 million gas boilers installed. This, along with the current low penetration of district heating (less than 10% at the European level, mainly in Germany, Poland, and Nordic countries), means a large volume of individual heating systems must be decarbonized, posing a significant technical challenge.

Electrification (heat pumps with insulation) offers an alternative solution whose abatement cost is lower than that of biomethane with insulation.[77] European energy policies encourage the deployment of heat pumps, building renovation, and energy efficiency improvements, drastically reducing natural gas consumption in the sector. The EC forecasts a sharp decrease in gas consumption in the residential sector, with around -65 bcm (-70%) to -76 bcm (-82%) between 2020 and 2040.

However, electrification of the building sector is encountering challenges. Heat pumps account for only 16% of residential and commercial building heating in Europe.[78] Heat pump adoption remains slow due to financial barriers, administrative challenges and rising electricity prices, which have partly discouraged residential consumers from switching to electric alternatives. This suggests that, in the short term, heat pumps alone cannot deliver heat decarbonization - or at least not quickly enough.

Biomethane is a cost-effective decarbonization solution, especially when other solutions are not feasible due to technical, regulatory and/or economic and financial constraints. Biomethane is compatible with existing infrastructure and gas-based space heating systems and district heating, thus requiring no investments at the end-use stage. It is an economical way to adopt renewable energy in heating, whether the system relies fully on biomethane or is hybrid, as is the case in hybrid heat pump systems. It enables municipal utilities to achieve a reduction in fossil fuels in the short term without immediately making far-reaching changes to the network infrastructure or customer systems.

Another important consideration when compared to full electrification of heating is the seasonality of heating demand. Daily and seasonal variations are a major feature of heating demand; accommodating them requires large

77. "Quelles contributions attendre de la biomasse dans la transition énergétique ?", *op. cit.*
78. "The Latest Heat Pump Statistics", HeatPumps London, updated May 2025.

volumes of energy as well as the appropriate distribution infrastructure. The EU gas network is able to cope with this challenge thanks to its scale (it covers over 2.2 million kilometers) and storage capacity (around 100 bcm). However, it is imperative that the network is promptly decarbonized. Several countries have adopted biomethane blending mandates for gas suppliers that will enable this decarbonization (Table 3).

A hierarchy for biomethane applications

The deployment of biomethane should focus on decarbonizing the hardest-to-abate sectors where viable alternative decarbonization options are not available within a reasonable timeframe or are technically unfeasible. Across all applications, four high-priority uses of biomethane emerge: high-temperature industry processes, chemical feedstocks, long-distance transport, including maritime transport, and flexible and dispatchable power generation. In addition, biomethane is a cost-effective decarbonization solution for buildings, when other solutions are not feasible due to technical, regulatory and/or economic and financial constraints. Biomethane injection into the gas grid is a no-regret option for adding more renewable energy to the system, displacing fossil fuels, and providing a renewable, dispatchable and storable molecule that enables the flexibility required by a decarbonized energy system.

These priorities evolve over time, according to innovation and market development. The abatement cost is a dynamic component of the energy system. It evolves according to technological developments linked to regulatory and market signals. When comparing the abatement costs of technologies at different stages of maturity, uncertainties must also be considered. Often, energy system models rely on overly optimistic assumptions about cost reductions and trade for low-emissions energy carriers, which distorts the competitiveness of the biomethane alternative.[79] The choice between hydrogen and biomethane for the decarbonization of certain segments, including very high-temperature heat in industry, power generation by thermal power plants during peak demand periods, and long-haul HDVs, must take into account the constraints related to the equipment/infrastructure required for these specific segments, as well as cost at the energy system level. Many low-carbon technologies require new supply chains, necessitating significant initial investment.

Currently, biomethane is often the cheapest or only available solution to reduce emissions in a short time frame, as required by EC regulation. More end-users, expected to decarbonize their operations with renewable hydrogen and its derivatives, are turning to biomethane/bio-LNG as a bridge fuel to meet their decarbonization targets, pending the fact that renewable hydrogen and e-fuels are a viable solution.

79. "Zukunftsaussichten der Biogasbranche", *op. cit.*

As 2030 decarbonization targets approach—and with high compliance costs looming under the EU Effort Sharing Regulation—transport and buildings have become top priorities for national policymakers. While power generation and industry have delivered the deepest emission cuts in Europe (electricity and heat down 58% since 1990 and industrial emissions almost halved), progress has been far weaker in other end-use sectors. Road transport is now the EU's worst-performing sector, with emissions 24% higher than in 1990, and buildings remain a major emitter despite a 40% reduction largely driven by efficiency gains and milder winters rather than structural change.[80]

For the biomethane use hierarchy, this clearly points to transport and buildings as the immediate priority — the sectors where decarbonization has lagged and where biomethane can deliver rapid, high-value emissions reductions. In the longer term, biomethane's end-use versatility and storability allow it to adapt to the needs of a fully decarbonized energy system, including supporting clean hydrogen production and balancing variable renewable generation.

Finally, while this ranking applies broadly to Europe, a hierarchy for biomethane end-use applications should be defined at the national level, where the value of the biomethane system can be maximized. Both costs and abatement potential vary not just between technologies but also very strongly within. This is because different countries have very different prices for key inputs, such as electricity and have different emission intensities.

80. "Key Trends And Drivers in Greenhouse Gas Emissions in The European Union", European Environment Agency, April 17, 2026.

Where is the strongest additional production potential in Europe?

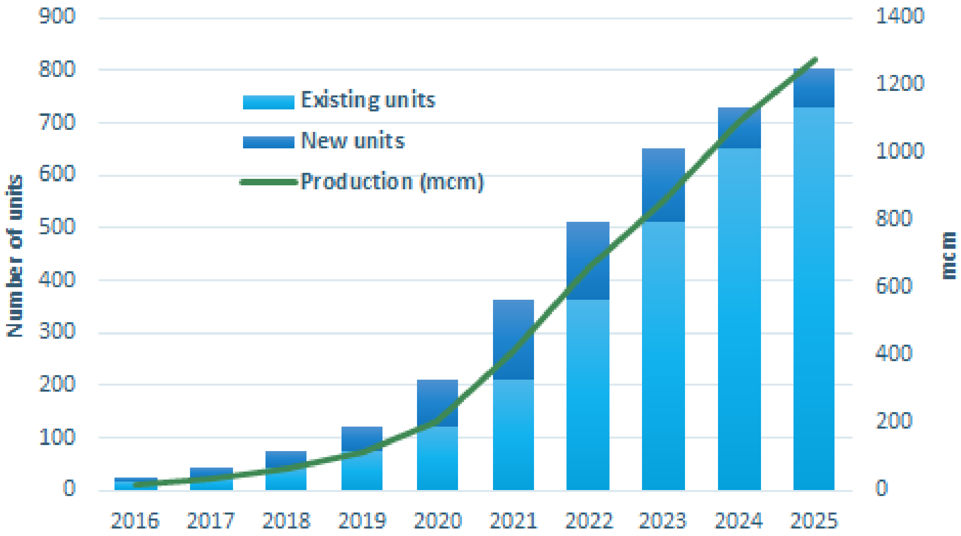
The availability of feedstocks is obviously a key factor that determines additional production potential in Europe. As seen previously, Germany, France, Italy, Poland, Spain, and the UK hold the highest feedstock potential. The extent of the gas grid is also a key factor, as is the current biogas infrastructure. Above all, the additional production potential is strongly correlated with policy support, the existence of credible targets to give long-term visibility and a clear framework. However, the situation is more complex as each European country faces unique challenges and opportunities. The stagnation of the German market provides an illustration of how an uncertain policy framework can slow down biomethane production growth, despite Germany holding the highest European feedstock potential, its intensive gas grid and fleet of biogas plants. On the contrary, the French surge in biomethane production provides the best case illustration of how long-term targets, an incentive framework (based on production subsidies and/or market pull), can activate the sector. The slower-than-expected development of Italian biomethane production (despite high potential, a developed gas grid and strong policy support) shows the importance of simplifying administrative permitting procedures and solving social resistance challenges. Similarly, the slow initial development of Spain's biomethane production (again despite high feedstock potential and a well-developed gas grid) illustrates the importance of a harmonized regulatory framework, policy support and a social license to operate. The UK case illustrates that biomethane growth is held back by regulatory uncertainty and a policy environment that has been slow to recognize the full benefit of biomethane.

This section provides an assessment of biomethane market trends and regulatory development in the six countries mentioned above, as well as in Ukraine, a country that has the potential to become a large biomethane exporter to Europe. It clearly shows that amid renewed geopolitical tensions, biomethane is no longer treated as a niche market. On the contrary, biomethane is now recognized as a key tool in the decarbonization toolkit alongside CCS, hydrogen and electrification, as well as a core pillar of energy security, sovereignty and the circular economy. In most of the countries where biomethane deployment had stalled or lagged expectations, a wave of regulatory reforms introduced since early 2026 is now unlocking investment, easing permitting and grid access, and positioning the sector for faster scale-up through the decade.

France: a model for European biomethane development

France has become Europe's biomethane leader, with production more than quadrupling since 2020 and surpassing 1 bcm in 2024. In 2025, output rose another 17% to 13.6 TWh (≈1.3 bcm), representing 3.9% of gas consumption in France.[81] France had 803 injection sites and a rapidly expanding project pipeline. Installed capacity reached 15.6 TWh/y at the end of 2025, while over 1,100 additional projects (19.2 TWh/y) were registered—evidence of exceptional growth.

Graph 3: France – Production of RNG and number of facilities (2016-2025)



Source: Open Data Réseaux Énergies (ODRÉ)

France's success is rooted in:

- A vast agricultural sector enabling large feedstock availability
- Strong public acceptance and proactive grid operators
- Stable, well-designed support schemes
- Facilitated access to the gas grid
- Clear long-term policy signals

A large share of biomethane plants consists of autonomous agricultural units of low to medium capacity (200 Nm^3/h on average), injecting into the grid (mainly at the distribution level). This trend reflects the orientation of the national biomethane policy that supports the development of the agricultural sector. Recent trends include the building of much larger plants,

81. "Gaz renouvelables & bas carbone : une solution crédible de souveraineté, de résilience et de décarbonation" [Renewable And Low-Carbon Gases: A Credible Solution for Energy Security, Resilience, And Decarbonization], Syndicat des énergies renouvelables, Gaz et Territoires, GRDF, NaTran, Teréga, April 9, 2026 ; "Observatoire de la filière méthane renouvelable et bas carbone" [Observatory of the Renewable and Low-Carbon Methane Sector], Open Data Réseaux Énergies, 2026.

diversification of feedstock with the emergence of projects based on household waste, and a growing volume of biomethane injected into the transmission network.

Policy remains the main accelerator. Feed-in tariffs support small units, while new market-based mechanisms—Biogas Production Certificates (CPBs) from 2026 and the IRICC transport decarbonization scheme from 2027—create strong demand for biomethane across buildings and transport.

Biogas Production Certificates (CPB)

Since January 2026, gas suppliers selling more than 400 GWh/year (and all suppliers within five years) must purchase or restitute CPBs in proportion to the gas consumed by their residential and commercial customers. The required biomethane share rises from 0.4% in 2026 to 4.2% in 2028 (0.8 TWh → 6.5 TWh). Suppliers can meet the obligation by producing biomethane or buying CPBs; non-compliance triggers a €100/CPB penalty.

CPBs are issued via an EEX-managed registry, with an active secondary market launched in 2025. Prices averaged €85.7/MWh in 2025, creating a strong revenue stream—especially for large plants outside the feed-in tariff. The scheme provides long-term visibility but currently has a defined trajectory only until 2028.

IRICC – Transport Carbon-Intensity Reduction Scheme

From 2027, the IRICC requires fuel suppliers to reduce the carbon intensity of fuels by 7.3% in 2027, rising to 18.1% in 2035, replacing the former Incentive Tax on Renewable Energy in Transport (TIRUERT) system. Obligated parties include fuel distributors as well as maritime, river, CNG and LPG sectors.

The IRICC is an essential tool for furthering the development of bio-NGV. Under the IRICC, bio-NGV will be able to generate certificates that can be sold to obligated parties, reinforcing France's already dynamic gas-mobility market: 39,000 NGVs and 750+ CNG stations by end-2025, and more than two-thirds of CNG consumption being from bio-CNG.

Towards 15% of French gas consumption by 2030

France's NECP (2024) sets a target of 44 TWh of injected biomethane (4.15 bcm) by 2030, equal to at least 15% of national gas consumption. The new Multi-Year Energy Plan (PPE 3),[82] adopted in February 2026, confirms

82. PPE 3: programmation pluriannuelle de l'énergie (2026-2023).

the 2030 target, followed by a range of between 47 and 82 TWh of biomethane injected by 2035. Taking into account biogas not injected into the network, this corresponds to approximately 50 TWh of biogases in 2030 and between 50 and 85 TWh in 2035. A clear target of 85 TWh in 2035 would better reflect the sector's true potential and provide stronger investment signals for project developers. By 2050, the 2025 draft of the National Low-Carbon Strategy (SNBC 3),[83] expected to be adopted in spring 2026 (not yet at the time of writing), sets a target of 106 TWh for gas, including 100 TWh of biomethane from anaerobic digestion and 6 TWh of renewable or low-carbon gas from complementary technologies (pyrolysis, hydrothermal gasification, and power-to-methane). The target lacks ambition and does not reflect the long-term biomethane potential. Long-term potential is far higher: national studies estimate ~150 TWh from anaerobic digestion alone by 2050, and 80+ TWh from emerging technologies—far above current official targets. Guidehouse estimates French biomethane production potential above 5 bcm/y in 2030 and 20 bcm/y in 2050. The 2050 production target is likely to be revised. To support this, France created a new "New Renewable and Low-Carbon Gas Technologies" working group in January 2026 within the CSF NSE to accelerate the industrialization of emerging renewable and low-carbon gas technologies.

Overall, France combines exceptional resource potential with strong, evolving policy tools, positioning the country for substantial, sustained biomethane growth by 2030 and beyond.

Germany: large biogas base, renewed momentum, but still missing a clear biomethane roadmap

Germany built Europe's biogas/biomethane success story. The country still dominates the European biogas sector, with around half of the European production and more than 11,000 plants, but Germany has lost its dominant position in the European biomethane market. Its share of European production decreased from 41% in 2019 to 23% in 2024. Germany saw strong growth in biomethane production in the early 2010s, but successive reforms of the Renewable Energy Act (EEG), which supports electricity generation from biomethane in CHP plants, have slowed progress. Production stagnated at around 1-1.2 bcm per year between 2017 and 2024. This highlights the importance of strong political will and an effective regulatory framework that provides long-term visibility for investors. In recent years, the German biomethane market experienced a challenging business situation marked by ineffective support mechanisms, insufficient investment security, fraud (fraudulent imports of waste-based

83. SNBC3: Projet de 3e Stratégie nationale bas-carbone.

biodiesel) and a price collapse in the GHG quota system, which resulted in the insolvency of two major traders and a loss of market confidence.

Since 2024, however, Germany has entered a phase of modest recovery. 21 new plants in 2024, the largest expansion for 10 years, and 18 in 2025 brought the total to 290 biomethane sites, injecting 12.8 TWh in 2025. Together with the 3.5 TWh of biomethane imported, 16.3 TWh of biomethane was sold on the German market, corresponding to 1.9% of total natural gas consumption. Growth is now driven mainly by transport, heat, and industry, while the role of biomethane in CHP continues to decline due to restrictive EEG tender rules. Nevertheless, to encourage greater participation in upcoming auctions, at the beginning of 2026, the German government increased the price ceiling for biomethane auctions by 10% (to €231.3/MWh), the maximum increase permitted by law.

The transport sector is the strongest driver: nearly 4 TWh of biomethane was used in 2025, supported by a rapidly expanding bio-LNG ecosystem (16 bio-LNG plants, 200 LNG stations). The revised GHG quota (THG-Quote) adopted in April 2026 sharply increases reduction requirements to 65% by 2040, strengthening demand for advanced biofuels, including biomethane, with a sub-target of 9% by 2040. The new legislation should drive further growth for biomethane, but the expansion of the NGV fleet will be a limited factor. Nevertheless, the growing demand for LNG in the maritime sector will offer a new outlet for bio-LNG.

The building sector creates a new field of application for biomethane and thus additional market growth. The new proposed Building Modernization Act (GMG) opens up significantly more technological freedom of choice with regard to the heating system used and also allows the installation of conventional heating systems beyond 2029. It replaces the 65% renewable heating requirement with a green-gas quota and a “Bio-Staircase” requiring rising shares of renewable gases in heating systems from 2029 onward (see Table 3). Biomethane is explicitly eligible in the green gas quota, which can be fulfilled via certificates, opening a new long-term market.

Industry is also emerging as a key consumer, illustrated by long-term BPAs such as BASF–Engie. Moreover, in May 2026, the EC has approved a €5 billion German state aid scheme to help industrial companies replace fossil fuels and raw materials with low-carbon alternatives, including biomethane.

Regulatory reforms are reshaping infrastructure access. The 2026 draft bill implementing the EU Gas and Hydrogen Package sets ambitious targets for the transformation of the gas transport infrastructure towards climate-neutral gas, which will significantly accelerate market uptake (contrary to the previous draft). It supports the reuse of gas networks and grants connection priority to new biomethane production facilities. However, it provides that, for existing installations, protection against disconnection from the gas grid will cease after ten years, a timeframe not sufficient to safeguard investments in existing facilities.

The role of biomethane is yet to be defined

With over 11,000 biogas plants operating in the country, producing some 80-90 TWh/y, Germany has been seen as the main contributor to EU biomethane production growth by 2030. However, there is still no clear roadmap for achieving the biomethane target for the REPowerEU strategy. Germany published its updated final NECP in August 2024, but there is no stated target for biomethane.

Studies show enormous potential: 78 TWh from upgraded biogas and 72 TWh of synthetic methane by 2035—150 TWh total, according to the IZES study, aligned with Guidehouse estimates of 7 bcm by 2030 and 20 bcm by 2050. With the expiration of EEG subsidies, converting parts of the massive legacy biogas fleet to biomethane will be essential. This conversion is facilitated by the existence of the already well-developed transport infrastructure and supported by emerging new market-oriented business models such as clustered upgrading, bio-LNG/CNG, CO_2 liquefaction, PtX, and flexible electricity in CHP plants. This diversified, high-value biomethane model is much more complex than the old model based on EEG subsidies. It requires optimizing the best use case of biogas, where the value depends on feedstock, infrastructure, and market demand. Under this background, the German Association of the Gas and Hydrogen has launched a Biomethane Task Force to coordinate industry action and strengthen biomethane's role in decarbonizing heat, transport, and industry.

Germany's vast biogas base, its abundant feedstock and political will, translated into recent improvement in the policy framework, mean that the country is now positioned for a steady biomethane expansion as clearer incentives and stronger demand in heat and transport begin to unlock its long-underused potential.

United Kingdom: reinforced policy support and rising energy-security imperatives

The UK's biomethane sector operates within the legally binding net-zero framework established by the 2008 Climate Change Act, which mandates five-year carbon budgets and guidance from the Climate Change Committee. Within this structure, biomethane is supported through a set of long-standing schemes. The Renewable Heat Incentive (RHI) drove early deployment until 2021–2022, after which support transitioned to the Green Gas Support Scheme (GGSS) —a tariff-based mechanism funded by the Green Gas Levy and underpinned by Renewable Gas Guarantees of Origin

(RGGOs). The GGSS launched on November 30, 2021 and was scheduled to close on November 30, 2025, but was extended until March 31, 2028. Participants receive tariff payments for a 15-year lifetime. In transport, the Renewable Transport Fuel Obligation (RTFO) requires fuel suppliers to blend a minimum proportion of renewable fuels. This is verified through the Renewable Transport Fuel Certificates (RTFCs) and increases yearly. The UK also has a SAF mandate, under which SAF from biomethane is eligible.

Biomethane production and the number of biomethane plants have remained stable since 2022 at around 0.7 bcm (0.75 bcm in 2024), and 120 (121 in 2024). Deployment under the GGSS has been limited so far, but is expected to grow. By March 2025, seven plants were fully commissioned, with a strong pipeline of 55 applications and 20 projects with tariff guarantees. Projects are typically medium-scale AD plants using waste feedstocks, reflecting a shift away from crop-based expansion.

Since 2024, the UK Government has consulted on a future framework for biomethane beyond the GGSS to fully appraise the right policy interventions to incentivize the biomethane industry to scale up and reach its potential. Policy signals in 2025–2026 reinforce biomethane's long-term role.

The GGSS is being extended. New regulations will push the commissioning deadline from March 2028 to March 2030. The application budget cap for 2026 to 2027 has been confirmed at £124.9 million. This will give developers more time to navigate planning, grid-connection and supply-chain constraints.

Mandatory food waste collections are adding feedstock. From 2026, mandatory household food waste collections across England will, for the first time, systematically add to the organic waste streams available for processing through AD. This is a significant structural change.

UK Emissions Trading Scheme recognition is in prospect. Two key policy decisions in 2026 will determine the pace of biomethane growth: the inclusion of biomethane in the UK ETS, and its recognition in the greenhouse gas protocol. Positive outcomes on both counts would significantly improve the economics of biomethane production and attract new investment.

The broader energy-security context is now reshaping the UK debate. The UK remains structurally exposed to volatile global gas markets, and the 2026 price shock has renewed political focus on domestic gas alternatives. Industry analysis suggests that, with existing assets operating at full capacity, UK biomethane output could rise to 9 TWh, replacing the entire volume of gas imported from Qatar in 2024.

The UK government is also considering adding market-based incentives, such as a market-based obligation for energy suppliers.

Nevertheless, several issues remain to be addressed. AD and biomethane plants face long, complex consenting processes. High costs and long delays in connecting to the gas network remain a major barrier. Mandatory food-waste collections will expand supply, but inconsistent regulations on allowable feedstocks (notably animal by-products) limit utilization and should be clarified. Biomethane remains under-recognized despite its clear benefits.

Another key issue is the non-recognition of UK GOs in the EU, which will limit cross-border trade.

The UK has a large potential for biomethane production. According to national assessments, up to 120 TWh of sustainable biomethane could be generated in the UK by 2050, far above today's utilization. Guidehouse estimates the UK potential at 2.5 bcm/y by 2030 and above 14 bcm/y in 2050. The UK already has more than 1,200 biogas plants. In 2024, a total of 33 TWh of biogas was produced, of which 7.9 TWh was upgraded to biomethane and injected into the grid. Thus, only 24% of biogas production is upgraded to biomethane, and only 25% of available feedstock is used.

Biomethane is now well recognized to be the most cost-effective and practicable solution to gas decarbonization today, with National Energy System Operator (NESO) Future Energy Scenarios (2025) recommending immediate and significant growth in production capacity across the UK. NESO's holistic transition pathway requires 64 TWh of biomethane production and use by 2050. The UK's largest gas distribution network (GDN), Cadent, has set a target to increase biomethane injection fivefold by 2035 (20 TWh).

With renewed growth in production in 2025/26, expanding feedstock streams and a focus on energy security, the UK is now laying the foundations for biomethane to become a strategic domestic gas resource as the GGSS extension and future post-2030 policies take shape. However, policy makers have to address remaining challenges, as well as continue working with the EC on the recognition of UK GOs in the EU.

Italy: rapid biomethane expansion, although slower than expected

Italy is experiencing a strong growth in biomethane production capacity, driven by a fast development of production units and an ambitious 2030 production target. Italy has introduced several support schemes, including feed-in tariffs and premiums, capital grants and quotas for the biofuels and transport sectors, strongly incentivizing biomethane production and initially directing the use of biomethane in the transport sector.

Production reached 417 mcm in 2024 (+32% y-o-y), with 118 plants in operation and a growing shift from early MSW-based mega-plants to agricultural and livestock feedstocks, which now dominate the development pipeline. Italy's leadership in gas mobility—1 million NGVs, over

1,700 CNG/LNG stations, and biomethane supplying 60% of NGV consumption—continues to anchor demand, with bio-LNG capacity expected to reach 3 TWh/y by 2026.

The development of the biomethane sector is based on three pillars: incentives and grants, Ministerial Decree of March 2, 2018 (DM 2018) and Ministerial Decree of September 15, 2022 (DM 2022), Guarantees of Origin (Ministerial Decree 224/2023), and contractual instruments and integration with industrial demand (Legislative Decree 63/2024).

- DM 2018, focused on transport, allocated €4.7 billion and supports up to 1.1 bcm/y of advanced biomethane via CIC certificates (certificates of biofuels released for consumption). Advanced biomethane benefits from double-counting.
- In January 2026, Italy passed new laws to transpose RED III, significantly boosting its biofuel targets. The legislation mandates a 16% share of biofuels in the fuel supplies of obligated parties, with a sub-target of 8% for advanced biofuels (doubled counting) by 2030. The advanced sub-target is historically divided to be met largely by advanced biomethane (roughly 75%) and other advanced biofuels (25%).
- DM 2022, part of the National Recovery and Resilience Plan (NRRP), promotes investments in new plants or reconverted plants (from biogas to biomethane) and encourages the development of biomethane and its injection into the gas grid for use also in non-transportation sectors, with a total production quota of 2.3 bcm/y by the end of June 2026 (now extended to June 2028). DM 2022 provides €2.2 billion in CAPEX grants (up to 40% of the investment) and €2.8 billion in 15-year feed-in-tariff or feed-in-premium. Five tenders in 2023-2024 awarded 2.1 bcm/y of capacity across 558 plants, 60% of which are conversions of existing biogas units.
- A new growth frontier is emerging in industry, supported by GOs (DM 224/2023) and long-term bilateral agreements enabled by Legislative Decree 63/2024. The decree allows bilateral agreements between biomethane producers and hard-to-abate industries. GOs can be transferred as a tool for decarbonization of hard-to-abate industries within the EU-ETS. The first biomethane plants with sales to the industrial sector entered operation in 2024–2025, with long-term BPAs signed by Engie, Edison and others.

Despite strong momentum, deployment has lagged behind the ambitious trajectories of DM 2018 and DM 2022 due to permitting delays, EPC bottlenecks, feedstock competition, grid-connection challenges, and regulatory complexities. The authorization process is slow and complex, and many communities oppose the construction of new plants on their territory (the so-called NIMBY (Not In My Back Yard) syndrome).

Recent reforms aim to accelerate progress: streamlined permitting (Legislative Decree 190/2024), SNAM's new role as Italy's single point of contact for all connection requests, and a major reform in grid-connection costs, with the share of connection costs borne by the producer falling from 80% to 30% of the total investment cost (ARERA 67/2026). New measures also encourage conversion of biogas plants, including mandatory conversion for units above 300 kW to access incentives beyond 2030 (Legislative Decree 21/2026). The collection of raw materials is also sped up by private initiatives, such as the agreement signed by Italgas and Coldiretti, the main farmers' association.

Towards 5 bcm+ of biomethane in 2030

Italy has a large biomethane potential. A recent study by the Italian Biogas Consortium (CIB) and SNAM estimates biomethane production potential at 8.1 bcm by 2030 and 15.3 bcm by 2050. Guidehouse estimates a similar long-term potential (14 bcm/y by 2050), but has a more conservative estimate for 2030 (4 bcm/y). Italy ranks second behind Germany in European biogas production, with 1,800 biogas plants producing 24 TWh in 2024. Italy's biomethane potential has attracted project developers and financial capital markets to massively invest in the Italian biomethane sector. Italy is among the top five countries in Europe in terms of planned biomethane investments to 2030.

The updated NECP (2024) confirms a 5.7 bcm biomethane target for 2030, with demand projected to reach 5 bcm, split between transport (1.1 bcm) and industrial/heat uses (3.9 bcm). However, current trajectories suggest production may reach 2.6–3 bcm by 2028, leaving a gap that will require additional measures to sustain growth in the second half of the decade. The government intends to respond with measures that can support the development of the sector until at least 2030.

Italy's strong incentive framework, expanding industrial demand and vast untapped agricultural feedstock position the country for sustained biomethane growth, with the sector now scaling rapidly towards its multi-billion-cubic-meter potential.

Spain: strong investment momentum and a rapidly strengthening policy framework

Spain's NECP targets 20 TWh of biogas and biomethane by 2030, yet production in 2025 remained low at 428 GWh from 20 plants —only 0.2% of national gas demand. Although output has nearly doubled in two years, deployment has been constrained by limited support policies, complex waste-logistics, high transport and connection costs, slow permitting (up to four years), fragmented regional regulation, and weak social acceptance of AD and biomethane projects. So far, regulatory support has been limited to some investment grants, the GO registry (since 2023) and biofuel quotas in the transport sector. Thus, the biomethane market has mostly relied on BPAs and sales to the transport sector.

Despite this slow start, Spain holds Europe's largest long-term biomethane potential. Sedigas, the Spanish Gas association, estimates the potential at 163 TWh/y, equivalent to half of current gas consumption, with more than 2,300 potential plant sites identified nationwide. Guidehouse assesses Spain's potential at 2.5 bcm/y by 2030 and 25 bcm/y by 2050, placing Spain at the top of Europe's potential ranking. This resource base is supported by a 96,000-km gas distribution network serving 20 million people.

Investor interest has surged accordingly. Spain is now the leading destination for planned private biomethane investment in Europe, with €4.8 billion expected by 2030 —up sharply from €1.5 billion in 2024. More than 200 projects are in development, driven by major players such as Enagás Renovable, Naturgy, Verdalia Bioenergy and Goldman Sachs. Nedgia, the gas distributor of Naturgy, already injects biomethane from 14 plants and has nearly 100 additional projects contracted, representing 5.8 TWh/y of injection capacity.

Regulatory progress accelerated in 2025–2026. The National Commission on Markets and Competition (CNMC)'s 2025 grid-access framework established clear, uniform procedures for injection, unlocking stalled projects and providing long-awaited legal certainty. While the cost of connecting a biomethane plant to the grid falls solely on the producer, legislation is being passed to introduce a better cost-sharing mechanism. Spain's draft RED III transposition also introduces ambitious GHG-reduction targets and sub-targets for advanced biofuels, biogas and RFNBOs, strengthening demand in transport and enabling cross-system GO traceability. The draft legislation envisions a system based on GHG emissions reductions, which will boost demand for biomethane with a lower carbon footprint.

Most importantly, Royal Decree-Law 7/2026 of April 2026 mandates annual biomethane consumption quotas beyond transport and introduces a seal of social, territorial and environmental excellence. According to the proposed related regulation, gas and LNG suppliers and direct market consumers will be required to demonstrate a minimum percentage of biomethane in their natural gas sales or consumption annually (this does not apply to power generation). This process would begin in 2028 with a quota of 0.5% and reach 6% in 2035, equivalent to approximately 10 TWh of biomethane. Biomethane plants eligible for these obligations must demonstrate their territorial, environmental, and social contribution. In addition to quotas, the draft includes measures to facilitate the connection of new renewable gas production facilities to the gas system and to leverage existing infrastructure. The proposed regulation represents a structural shift for the sector and will accelerate investment. It ensures long-term growing demand, while streamlining permitting and improving community acceptance.

Spain has now entered a clear growth phase. While current production remains modest at 0.4 TWh, the combination of strong investor appetite, a large project pipeline, and a rapidly improving regulatory environment positions Spain to become one of Europe's leading biomethane producers. Spain's huge biomethane potential also positions the country as a future exporter of biomethane and bio-LNG.

Poland: high potential, early market stage

Poland is an emerging biomethane market with very large but still untapped potential. The country commissioned its first pilot plant in early 2025 and its first commercial plant in October 2025, injecting biomethane into the Polska Spółka Gazownictwa (PSG) grid, Poland's largest natural gas DSO, part of Polish energy major Orlen. With one of Europe's largest agricultural sectors and a well-developed gas network, Poland ranks among the top five EU countries for biomethane potential. Government assessments indicate 8 bcm of technical potential by 2030, with 3.2-4.7 bcm achievable. Guidehouse estimates the biomethane potential at around 3 bcm/y by 2030 and 12 bcm/y by 2050. A study by Gaz System, Poland's transmission system operator (TS, has identified a very large potential for the use of biomethane by consumers connected to gas networks– at the level of 7 bcm/y.

Project development is accelerating. As of Q3 2025, the Polish Biomethane Organization identified 123 projects (829 mcm/y of capacity), including 30 advanced projects having received environmental approvals. Some of these projects already have gas grid connection conditions issued by Gaz System and PSG, positioning them well for early market entry. Most projects are small- to medium-scale (1–5 MW), reflecting the fragmented agricultural landscape.

A new support framework is being rolled out. Since 2024, plants up to 1 MW receive a feed-in premium, while Poland is introducing an auction-based support system for larger plants (above 1 MW), provided that biomethane is fed into the gas network (draft amendment to the Renewable Energy Sources Act). Support will be provided in the form of a contract for difference available for a maximum period of 20 years. The proposed mechanism will support the production of approximately 300 mcm/y of biomethane, which will require the construction of approximately 50 installations by 2030. The system will be funded largely through the

Renewable Energy Fee. The draft amendment also allows all agricultural biogas plants above 1 MW to be located on the basis of a municipal council resolution.

Additional funding comes from the National Recovery Plan, the Modernization Fund, and NFOŚiGW programs offering grants covering up to 45% of CAPEX. Private investment is also rising, with major players such as TotalEnergies/HitecVision, SUEZ, Eiffel, Axpo and ORLEN expanding aggressively. According to EBA, the sector will receive €1.09 billion of private investment by 2030.

Grid connection remains the main bottleneck, as many biogas plants are too remote or face limited network capacity. To address this, Gaz-System is deploying Gas Fuel Transfer Facilities enabling bio-CNG transport to injection points, while PSG has published an absorption map to guide siting. Direct pipelines to end-users are also being facilitated. An April 2026 amendment to the Energy Law eases administrative and technical barriers for new projects.[84] The reform improves grid-connection certainty, shortens decision timelines, simplifies procedures and reduces formal requirements. It also obliges grid operators to factor future biogas and biomethane projects into their investment plans—significantly increasing the likelihood that new plants can connect and operate reliably.

Other incentives for the development of the sector are also considered, such as the possibility of implementing mechanisms to stimulate demand for biomethane.

Poland's draft updated NECP (2025) sets targets of 1.5 bcm by 2030 and 3.9 bcm by 2040, with biomethane expected to play a growing role in industry, heavy transport, power (peak units, to balance intermittent renewables, and CHP) and agriculture. The introduction of biomethane into gas networks is a priority, with the share of biomethane in gas networks projected to grow over time.

Poland's vast agricultural resources, strong policy push, rapidly growing project pipeline and rising investment position the country for a major biomethane scale-up as new support schemes and grid-integration reforms take hold.

Ukraine: an emerging biomethane exporter with large, still untapped potential

Ukraine holds one of Europe's largest untapped potentials, with 17.8 bcm/y of sustainable biomethane potential according to the Bioenergy Association

84. A. Ujazdowski, "Poland's Biogas And Biomethane Market Needs Stronger Support to Unlock Its Full Potential", *Poland Insight*, April 13, 2026.

of Ukraine (UABIO), supported by Europe's largest agricultural area, low production costs (≈€50/MWh), and a well-developed gas network interconnected with EU countries. Despite the absence of a domestic support scheme until now, Ukraine has quickly positioned itself as an export-oriented producer, launching its first biomethane plant in 2023 and expanding to five plants by the end of 2025 (including two bio-LNG units) with a combined capacity of 52 mcm/y.

Exports were enabled in late 2024, and Ukraine completed its first export of biomethane by pipeline to Germany in February 2025 and its first bio-LNG delivery in May 2025. However, large-scale exports remain constrained by the lack of an EU framework recognizing biomethane from third countries; PoS and GOs from Ukraine are not yet accepted, leading producers to inject biomethane into storage while awaiting regulatory clarity.

In April 2026, Ukraine adopted a national program to accelerate biomethane development, supporting new plants, upgrading existing biogas units, and simplifying grid-connection procedures. The plan targets 1 bcm/y by 2030 and 2.1 bcm/y by 2035. Under UABIO's high scenario, production could reach 1 bcm by 2030, 4.5 bcm by 2040, and up to 20 bcm by 2050, with roughly half exported to Europe—requiring around 4,000 plants and €40 billion in investment.

Ukraine's vast feedstock base, low production costs and accelerating export-oriented development position it to become a major long-term biomethane supplier to Europe once regulatory pathways for third-country imports are fully established.

Conclusion and recommendations

The European biomethane market is at a decisive moment.

On one hand, biomethane has become a strategic asset for the European energy transition. Policy instruments like RED III, the ETS and ETS2, the FuelEU Maritime Regulation and the Clean Industrial Deal create strong demand for biomethane, in particular for low-CI biomethane. There is a broadening of biomethane uses and a move towards more strategic uses, decarbonizing the gas grid and the transport sector, including maritime transport, enabling energy-intensive industries to reduce their emissions, while providing the flexibility required by the energy system. New models are developed to finance biomethane plants, beyond the subsidy-driven model. BPAs are emerging as a cornerstone of growth. In addition, the multiple benefits of biomethane in energy, environmental and agricultural systems are better monetized, notably through the sale of biomethane certificates, biogenic CO_2 and nutrient-rich digestate.

On the other hand, the European market is still in a complex stage of development. There has been no sustained decline in biomethane production cost across Europe since the late 2010s, due to inflationary pressures and rising project complexity. Although the sustainable biomethane potential is high, competition between end uses is growing as the pressure to decarbonize the entire economy intensifies. Additionally, competition from other bioenergy sectors will increase as they tap into the same biomass resources as biomethane from gasification. The general consensus, however, is that the overall additional biomethane potential remains high. Often, biomethane's role in decarbonization strategies is not defined by thorough energy system models. When such models are used, they often rely on overly optimistic assumptions about cost reductions and trade for low-emission energy carriers. This distorts the competitiveness of the biomethane alternative.

Despite growing momentum, the REPower EU target is unlikely to be met. The rapid growth of the biomethane sector remains constrained by inconsistencies in EC regulation and by several persistent barriers. Funding disparities persist, with biomethane receiving less policy attention and financial support than other renewables such as solar, wind, or green hydrogen —slowing deployment. These points were recently emphasized in a joint biomethane declaration by industry associations representing sectors that are difficult to abate.[85] The declaration calls for the removal of barriers to the accelerated rollout of biomethane and the establishment of an EU Biomethane Bank support scheme.

A rapid expansion of the sector depends on several critical enablers.

- A European clear and stable legislative framework setting a level playing field for biomethane, with no market entry barriers, inconsistencies and gaps in regulatory frameworks and effective support schemes or demand pull (such as blending mandates). A binding EU-wide target for biomethane production would give long-term certainty to project investors.
- A harmonized and unified certification framework. Finalizing the UDB and harmonizing registry systems for certificates with consistent tracking and trading mechanisms is crucial. This will enable the sector to operate as a cohesive, continent-wide market.
- Persistent constraints in permitting must be addressed, and gas connections must be accelerated.
- Cross-sector integration —linking biomethane plants with agricultural, food-processing, municipal and industrial partners— should be promoted to secure high-quality, reliable feedstock.
- The economic competitiveness of biomethane must be improved through the valorization of co-products and production cost reductions.
- Biomethane certificates in carbon compliance mechanisms must be clearly recognized to enable large-scale development of BPAs between industrial consumers and producers.
- Lastly, given competition for sustainable biomass resources, the use of biomethane should be prioritized in applications where it provides the highest system value with the greatest emission reductions, and where no other decarbonization options can deliver the same combination of GHG reductions, circularity, and system services. A hierarchy for biomethane use should be defined at the national level, where the value of the biomethane system can be maximized.

85. "Joint Biomethane Declaration: Accelerating Biomethane Deployment to Strengthen Europe's Competitiveness, Energy Security and Industrial Decarbonisation", EBA, Cefic, PFP, Cepi, COGEN Europe, Copa and Cogeca, Farm Europe, Fertilizers Europe Glass for Europe, IFIEC Europe and SEA-LNG, March 24, 2026.

ifri
french institute of international relations
since 1979

27 rue de la Procession 75740 Paris cedex 15 – France

Ifri.org