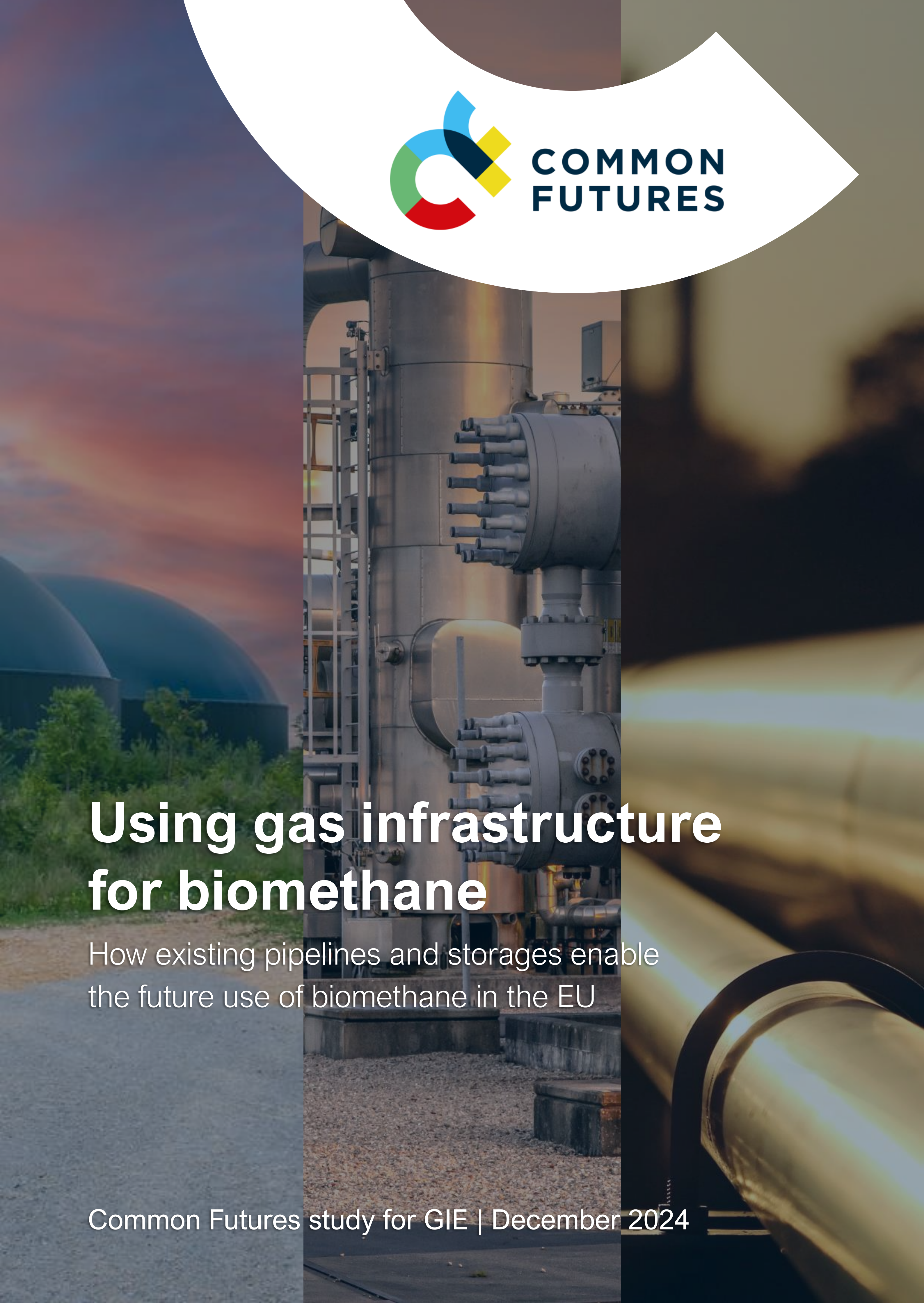

COMMON FUTURES

# Using gas infrastructure for biomethane

How existing pipelines and storages enable the future use of biomethane in the EU

Common Futures study for GIE | December 2024

**This report was prepared for the Biomethane Area of Gas Infrastructure Europe**

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**Date:** 11 December 2024

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# Executive Summary

Existing gas infrastructure is indispensable for transporting and storing growing quantities of biomethane, enabling biomethane to play a valuable energy system role. In addition to gas pipelines needed to collect biomethane in production areas, methane transmission pipelines and storage capacity are needed to deliver green gas molecules where and when required. These are the main conclusions of this study, based on analysis of the future need for gas pipeline and storage infrastructure to enable the growing use of biomethane in five end use sectors in the EU by 2040. This study concludes that underground gas **storages** will be needed, to facilitate the use of biomethane in heating of buildings and in dispatchable power generation in particular, due to the **mismatch** between **seasonal demand** and **almost continuous biomethane production**. The need for gas **transmission pipelines** for biomethane is **driven by the daily and hourly imbalances** between supply and demand, both within and between regions. By strategically connecting areas with surplus biomethane supply to regions with higher consumption needs, these pipelines ensure balanced, efficient, and resilient flows of renewable energy across the EU.

This study combines EU-level analysis to determine the need for gas storages and connected pipelines (based on existing studies and scenarios), with a regional analysis to investigate required pipeline capacities to match supply and demand across different locations.

Our base scenario has 101 bcm of biomethane supply and demand in the EU by 2040, as outlined in a recent study for the EBA. The vast majority of this biomethane (98 bcm) is assumed to be injected into the gas grid. Assumed gas demand is largely based on the National Trends+ scenario from the ENTSOG and ENTSO-E Ten-Year Network Development Plan 2024, which, combined with a dedicated analysis on future gas demand in buildings in a year with relatively cold weather, leads to 240 bcm of total gas demand by 2040. Of this demand, 237 bcm is assumed to be served by gas from the grid, consisting of 98 bcm of biomethane plus natural gas and e-methane. This means that this study assumes that grid-injected biomethane makes up 41% of the 2040 methane mix.

Analysis for four different typical European regions, varying in biomethane supply and biomethane demand in buildings, industry, power generation, and for shipping and trucking fuels, shows large mismatches in annual supply and demand. These mismatches are not only annual, with large variance in supply and demand in the regions on an hourly and daily basis, leading to varying flows to and from storages and/or other regions. From this analysis, it can be concluded that significant gas transport capacity will be required. The study shows that the analysed regions of around **8,000 km²** (an area with a radius of 50 km) can require up to **8.9 GW of transport capacity for biomethane alone** to the region, and substantially more for all methane needs and transit flows together; this is a capacity typically provided by gas transmission pipelines. This shows that **large existing pipelines will be needed in the future for biomethane**. An extensive network of pipelines will be needed because industrial and urban demand centres are concentrated while biomethane production is more distributed.

Looking at storage, the peak withdrawal need from gas storages remains at a high level in 2040 compared to today. The required withdrawal rate – just for biomethane - in a situation with high demand for heating and dispatchable power is 184 GW across the EU. **This peak withdrawal in 2040 is 40% of the most recent natural gas peak withdrawal,** witnessed in 2018. As a result, the required pipeline capacity connecting these storages to consumers in the buildings sector and to electricity producers – needed in a cold weather year – are also significant.

The use of gas in the energy system will change towards 2040, with a higher share of gas used in demands without a significant seasonal demand such as industry or transport fuels. Despite this, **gas use in heating and power generation will still require substantial storage capacity.** The future share of biomethane demand in these two sectors will require approximately 183 TWh of gas storage in the base scenario, i.e. about **18 bcm of methane storage**. Such demand for gas storage would require the use of almost 20% of today's natural gas storage capacity for biomethane by 2040.

This study shows that in 2040 the **ratio of peak demand to annual demand for gases is expected to increase,** both in heating of buildings – especially in the case of hybrid heating systems – and in dispatchable power generation, in a system with a high share of wind and solar electricity. This impacts the different needs from storage, with an increasing importance of withdrawal and transport capacities for (bio)methane infrastructure in 2040.

Total methane storage needs can be expected to reduce with the assumed growing market share for non-gas heating systems (electric heat pumps, district heating) and gradually improving insulation of the building stock. However, growth in underground storage of other molecules such as hydrogen will likely offset the reduction in methane storage needs.

**In a sensitivity analysis for a more conservative biomethane scenario** (72 bcm of biomethane by 2040, as used in the Ten-Year Network Development Plans for the EU), **we found that the qualitative findings remain broadly the same, and that significant infrastructure is required** to match biomethane supply and demand across the EU throughout the year.

**Using gas infrastructure for biomethane requires relatively modest new investments**. Some €2.5 billion will be needed annually by 2040 for gas grid investments to support the integration of large volumes of biomethane. This cost will be split between the biomethane plant and the gas grid operator at a varying rate depending on the investment and the country. This level of investment is small compared to the required investments in electricity grids, which are 40 times higher at €100 billion per year to 2040.

**This study also estimates that the costs of maintaining and operating the existing gas infrastructure to connect supply to demand and storage locations will not change significantly from its level today**. Gas transmission system operators data submissions to regulators on tariff structures show that current average transmission tariffs are around €3.70 per MWh. Decreasing volumes of transported natural gas up to 2040 will have an upwards effect on the tariff. On the other hand, operational costs are likely to decrease, because existing gas infrastructure (the current regulated asset base) will be increasingly depreciated. Also, some assets will be repurposed to be used for the transport and storage of hydrogen (and transferred to the regulated asset base for hydrogen). As these differing effects will counteract each other, it can be assumed that the 2040 tariff for maintaining the current transmission grid will stay in a relatively similar order of magnitude compared to the tariff today.

This report brings building blocks for a vision on how methane infrastructure can contribute to meet EU climate goals at the lowest overall system cost. It provides a **starting point for the role of methane infrastructure in the necessary integrated energy system planning**.

# 1. Introduction

**Purpose and background of this study**

Biomethane production and consumption in the EU are growing rapidly and authoritative scenarios by the European Commission and combined electricity and gas network operators expect significant further growth in the coming years. Sometimes, biomethane is viewed as a local affair, produced in rural areas and distributed to local consumers via local gas networks, but as biomethane volumes grow, so will its role in the EU energy system. In the future, it can be expected that biomethane is used in many sectors across Europe, making use of large-scale gas infrastructure to connect producers and consumers via pipelines and to balance supply and demand by also using underground storages. Yet the role of Europe's gas infrastructure to facilitate biomethane has not yet been researched in detail. In this study for Gas Infrastructure Europe (GIE), Common Futures analyses the extent to which existing gas infrastructure will be needed to facilitate future volumes of biomethane.

The European Union has a well-connected, highly flexible critical gas infrastructure, consisting of 260,000 kilometres of large pipelines, 33 LNG terminals and around 150 underground gas storages. Today, this infrastructure is used to import, transport and store about 350 billion cubic metres (bcm) of natural gas per year. Increasingly, the infrastructure will be needed for biomethane as well. The EU currently produces 5 bcm of biomethane, and this quantity is rapidly increasing. During the coming few years, this production will more than double, following the latest announced investments of €20 billion in new EU biomethane production capacity in the coming years[1]. By 2030, the EU targets a production of 35 bcm (or about 350 TWh) per year. The Ten-Year Network Development Plans (TYNDP) of EU electricity and gas infrastructure operators expect significant further growth in biomethane up to 2040 and beyond.[2] While some biomethane is consumed locally close to its production, most future uses of biomethane will be located further afield and gas transport infrastructure will be needed. Storage infrastructure will be needed as well because of higher demand during the winter period while biomethane production remains relatively constant throughout the year. The infrastructure for this consists largely of existing gas pipelines and storages, with relatively modest operational and maintenance costs and with some limited necessary investments to connect biomethane production plants to grids and for booster stations to bring biomethane from low-pressure distribution grids to higher-pressure transmission grids.

**Study scope**

This study analyses the expected pipeline capacities, storage volumes and storage withdrawal capacities that will be needed to connect biomethane supply to end consumers by 2040. For supply, this analysis uses the results of a recent potential study performed by Guidehouse for the European Biogas Association, that shows a biomethane production potential of 101 bcm in the EU by 2040.[3] In addition, as a sensitivity a more conservative supply scenario of 72 bcm biomethane by 2040 – as found in the Ten-Year Network Development Plan 2024 scenarios developed by ENTSO-E and ENTSOG - is considered.[2] Biomethane can reach supply via existing grid infrastructure, but it can also be produced and transported in compressed or liquid form as bio-CNG and bio-LNG respectively. This occurs

[1] European Biogas Association (2024), *2nd EBA Investment Outlook on Biomethane*, [Link]
[2] ENSTO-E & ENTSOG (2024). *TYNDP 2024 Draft Scenarios Report 2024* [Link]
[3] Guidehouse (2024). *Biogases towards 2040 and beyond*. [Link]

typically in regions where the gas grid is too far away. This study assumes that 5% of produced biomethane in 2040 is directly consumed as bio-CNG/bio-LNG.

The use of growing volumes of biomethane has significant energy system benefits as the energy system transitions to net zero emissions. On the demand side, this study analyses the use of biomethane in five end use sectors: (1) heating of buildings, (2) industry, (3) electricity production, (4) international shipping, and (5) heavy road truck transport. Additional uses for biomethane are possible, for example in agriculture, so the demand analysis in this study is non-exhaustive. The future role of biogas is out of scope of this study. Large volumes of biogas (not upgraded to biomethane) are produced in the EU. This biogas is used locally, e.g. in CHPs, and does not use gas infrastructure, losing the possibility to be stored in underground gas storages and be used flexibly. Biomethane injected to gas infrastructure with access to gas storages can be used flexibly, with a high value in the energy transition.

This study aims to present new insights for the use of pipelines and storages, based on specific scenarios for biomethane across the EU. It does not aim to provide a detailed analysis of the future use of individual pipelines or storages. The future of individual pipelines and storages is very dependent on national strategies and the scale up of other renewable gases such as hydrogen.

From a market perspective, biomethane injected to the gas grid can be sold to consumers anywhere in Europe in any gas using end sector with the use of guarantee of origin certificates, in the context of compliance with the EU Renewable Energy Directive. However, from a physical perspective, biomethane injected to gas infrastructure gets blended with natural gas and it will be used interchangeably with gas in all of its end uses without the possibility to physically link specific consignments of biomethane supply to specific consumers (in the same way as green electrons are delivered to specific consumers). This study aims to analyse real-world infrastructure implications, and thus, treats biomethane as methane, used interchangeably with natural gas (and in the future also e-methane) by end consumers.

**Approach**

The study first analyses the need for underground gas storage for biomethane and subsequently analyses required gas pipeline capacities. The need for storage is analysed at EU level, based on TYNDP 2024 data yet performing own analysis on the built environment. The main applications of biomethane needing storage are assumed to be the heating of buildings and dispatchable power production. Both for the purpose of supplying buildings and power plants, large quantities of biomethane may be needed within short periods of time. Therefore, the required withdrawal capacity of storages is analysed alongside the storage volumes needs.

Subsequently, the study analyses pipeline capacity needs. This relates to the need to transport biomethane to and from underground gas storages, and to bridge the distance between producers and consumers. This analysis is done by evaluating demand and supply in and around four archetype regions.

Finally, the report evaluates the cost of maintaining existing gas infrastructure to facilitate biomethane, plus the need for (limited) additional investments to connect producers to both the low and high pressure grids, the cost of reinforcing low-pressure grids, and reverse compression stations to ‘boost’ biomethane injected in local grids towards higher-pressure interregional networks.

**Reading guide**

The next chapter analyses the future need for gas storages for biomethane, followed by an analysis of pipeline capacity needs in Chapter 3. Chapter 4 provides a sensitivity analysis that analyse gas infrastructure needs in a scenario in which biomethane supply by 2040 will be limited to 72 bcm. Finally, Chapter 5 discusses gas infrastructure costs to facilitate biomethane and remaining natural gas. More details on the analysis including assumptions detailed results are presented in the Appendices.

# 2. Future use of gas storages for biomethane

## 2.1 Aim and overall results

The aim of this chapter is to investigate the required gas storage to enable the large scale use of biomethane in 2040. This analysis is performed at EU-wide level, using TYNDP 2024 combined with a biomethane supply estimate based on the EBA 2024 study and additional analysis on future gas demand in buildings. The analysis aims to provide insight into how much of the current methane storage volume and withdrawal capacity of the roughly 150 underground gas storages across the EU will be necessary to enable biomethane to be effectively used for emissions reduction efforts. Additionally, the analysis focuses on end-uses of biomethane with the greatest impact on storage needs in the future, namely the heating of buildings and electricity production.

**Storage will be essential to enable the use of biomethane in buildings and electricity production**. Biomethane has a relatively stable supply profile while gas demand will remain highly variable, with a profound seasonal demand pattern in the heating of buildings and dispatchable electricity production. This means that existing gas storage facilities will be indispensable for the integration of large volumes of biomethane into the energy system; particularly in periods with a high demand compared to supply.

**About one fifth of current withdrawal capacity is required for biomethane in moments of peak gas demand.**
In 2040, the role of gas storage will evolve compared to today, with significant volumes of biomethane required in concentrated peak moments. A seasonal mismatch between supply and demand of gas remains, requiring significant storage volumes, however, peak moments become a larger share of the total methane demand. As such, having sufficient withdrawal capacity becomes crucial. This is shown by the peak-to-volume ratio for storage needs, reflecting the growing volatility in gas demand, driven by changes in the technology mix of both the built environment and electricity generation.

**Energy demand in buildings remains seasonal, with pronounced moments of peak demand**
Even assuming a reduced share of buildings connected to the gas grid and with a reduce role for gas boilers, gas use in buildings is expected to remain significant, and be strongly concentrated in the cold winter months. The changing building stock and large deployment of hybrid heat pumps will lead to this demand becoming increasingly peaky, with the heat pump component covering the heating demand for large parts of the year for the majority of the studied building stock, but cold weather events necessitating high biomethane withdrawal from storages to ensure homes remain heated.

**Biomethane use in electricity production requires rapid withdrawal of biomethane from storages**
Although the TYNDP NT+ scenario predicts a reduced role for methane in electricity generation, biomethane will still be vital during periods of low variable renewable energy availability, requiring rapid, large capacity withdrawal of gas from storage in 2040.

**Biomethane supply will have a slight seasonality, with peak supply in warmer summer months, opposite to the peak demand during cold winter months.**
Biomethane supply is expected to have a slight seasonality as a result of the influence of temperature on production from anaerobic digestion plants. It is estimated that 47 % of supply occurs in winter months, while 53% of supply occurs in summer months. This slight seasonality is opposite to the pronounced seasonality of demand, which peaks in the winter, and thus, increases the need for connection to transmission and storage infrastructure to match supply and demand in time.

## 2.2 Brief description of assessment methodology

To assess the EU's biomethane storage needs by 2040, we developed supply and demand profiles for biomethane, using the methodology below, which is expanded upon in Appendix 1.

**Supply Analysis:**
Supply projections in this study are based on the recent study for the European Biogas Association,[4] which estimates the EU's biomethane production potential at 101 bcm. Two key production methods were considered: anaerobic digestion and gasification. Anaerobic digestion was assumed to exhibit seasonal variation, with 45% of supply in winter months and 55% in summer. In contrast, gasification was assumed to be a baseload supply, providing consistent output year-round.

**Demand Analysis:**
Demand profiles were developed by evaluating key biomethane end-uses. The built environment and power generation were found to be large seasonal demands, while industry, shipping, and trucking were found to typically have a more stable, baseload demand. Methane demand for power generation, industry, shipping, and trucking was taken from the Ten-Year National Development Plan National Trends + (TYNDP NT+) scenario, which provides a well-established framework for future energy demand projections.[5]

For the built environment, a separate analysis was conducted to estimate gas demand in 2040. This analysis utilised EU daily gas demand data for the residential and commercial sector on a national level and corresponding temperature data to establish a temperature-to-gas demand relationship. Based on this relationship, and assumptions on the 2040 housing stock—such as technology mix, renovation rates, and the operational behaviour of hybrid heat pumps—a gas demand profile for 2040 was generated. This profile was developed under the assumption of a "1-in-20" cold weather year in line with expectations for infrastructure from EU regulation[6], ensuring it reflected the level of demand that should be considered when designing suitable infrastructure. Analysis including a normal weather year can be found in Appendix 3.

The assumed methane and biomethane use per end sector can be found in Table 1. This shows that our study is grounded in the TYNDP NT+, with additional analysis on the built environment leading to

[4] Guidehouse (2024). *Biogases towards 2040 and beyond*. [Link]
[5] The TYNDP NT + scenario is based on national priorities and policies such as National Energy Climate Plans (NECPs), National Long Term Strategies, and other strategies of European countries, with gap filling measures to reach European targets. It is chosen for this analysis as it has less overly favourable assumptions for electricity based flexibility assumptions as in Global Ambition and Distributed Energy scenarios. See Appendix 1 for more details on the TYNDP, and its scenarios.
[6] Regulation (EU) 2017/1938. Article 5 & Article 6 [Link]

the one deviation in results from the TYNDP. It is important to note that with a biomethane supply of 1,071 TWh (101 bcm) in 2040, this is only a share of total methane. To focus on the physical implications of biomethane use in the grid we assume a proportional division of biomethane across all end uses, with a 41% share of all methane supply, demand, and storage being attributed to biomethane across the energy system.[7]

*Table 1. The methane use in demand sectors for 2019 and 2040 from TYNDP 2024 and the methane and biomethane use assumed in this study.*

| | EU Reference 2019 (methane) | TYNDP NT+ 2040 (all methane) | This study 2040 (all methane) | This study 2040 (biomethane) |
|---|---|---|---|---|
| *Sector* | | *TWh* | | |
| **Residential & tertiary** | 1,402 | 599 | 822[8] | 345 |
| **Transport** | 23 | 145 | 109[9] | 45 |
| **Industry** | 1,034 | 596 | 596 | 250 |
| **Agriculture** | 38 | 16 | 16 | 7 |
| **Power generation** | 1,218 | 649 | 649 | 272 |
| **Non-energy use** | 178 | 114 | 114 | 48 |
| **Steam methane reforming** | - | 134 | 134 | 56 |
| **International maritime bunkering** | - | 75 | 75 | 32 |
| **Other** | 26 | 0 | 0 | 0 |
| **Total** | 3,918 | 2,328 | 2,514 | 1,035 |

**Assessment of the need for gas storage**

Biomethane storage requirements are determined from the hourly and annual differences between supply and demand profiles. The proportion of biomethane within total methane demand across all sectors was used to allocate storage needs accordingly. The resulting biomethane storage needs are only a part of the story, with remaining gas demand requiring additional storage capacity for e-methane and natural gas. Total methane storage needs are not calculated in this study.

Section 2.3 will detail the overall storage and withdrawal capacity needs for biomethane in 2040, with a comparison to the share of today's infrastructure this would require. Section 2.4 outlines how this comes as a result of technological switches which create a new demand profile for biomethane in 2040. Section 2.5 focuses on how these changes in the built environment (like the deployment of hybrid heat pumps) will influence storage requirements, while section 2.6 explores how biomethane will be used in power generation and why withdrawal of methane from storage will be vital, especially during a "Dunkelflaute[10]"

[7] See Appendix 1 explaining the biomethane grid share of 41%.

[8] The increase in residential & tertiary gas demand compared to the TYNDP NT+ results comes from the choice for a '1-in-20' weather year. See the sensitivity analysis on this in Section 4.2.

[9] Total methane demand for transport is taken from the TYNDP NT+, this table represents the grid share of methane to transport. The difference is met by bio-LNG directly supplied to refuelling stations without entering the grid.

[10] Consecutive days with low electricity generation from solar and wind. Gridx.

or extreme cold spells. Sub-section 2.7, concludes the chapter and provides insight into why baseload demands have a limited impact on overall storage needs.

## 2.3 Large withdrawal capacity from gas storages needed in the future

The peak withdrawal needs from storage in 2040 are significant, with a substantial share of current methane storage volumes required for biomethane. In 2040, 184 GW of withdrawal capacity and 183 TWh volume of storage is needed to enable the valuable use of biomethane in 2040, as seen in Table 2. This is a notable share of the current underground storage capacity today, showing the increased importance of biomethane in the gas mix in 2040.

*Table 2. Overview of main characteristics on biomethane storage needs in the base scenario with a EU biomethane potential of 101 bcm*

| Main characteristics analysed | | | | | |
|---|---|---|---|---|---|
| **Storage volume needs** | *TWh* | 183 | Share of current methane capacity[11] | % | 16 % |
| **Peak withdrawal needs** | *GW* | 184 | Share of current methane capacity | % | 22 % |

This storage need was determined using EU biomethane supply, demand, and storage profiles as shown in Figure 1 and 2. Our analysis indicates that the peak biomethane demand from the grid in the EU in 2040 is estimated to be 294 GW. Biomethane supply has a relatively flat profile, with 126 MW per hour baseload supply in the summer, and 110 MW per hour baseload supply in the winter. As demand peaks in the winter and is much more variable, there is a significant balancing required from storages, with a peak withdrawal capacity from methane storages of 184 GW.

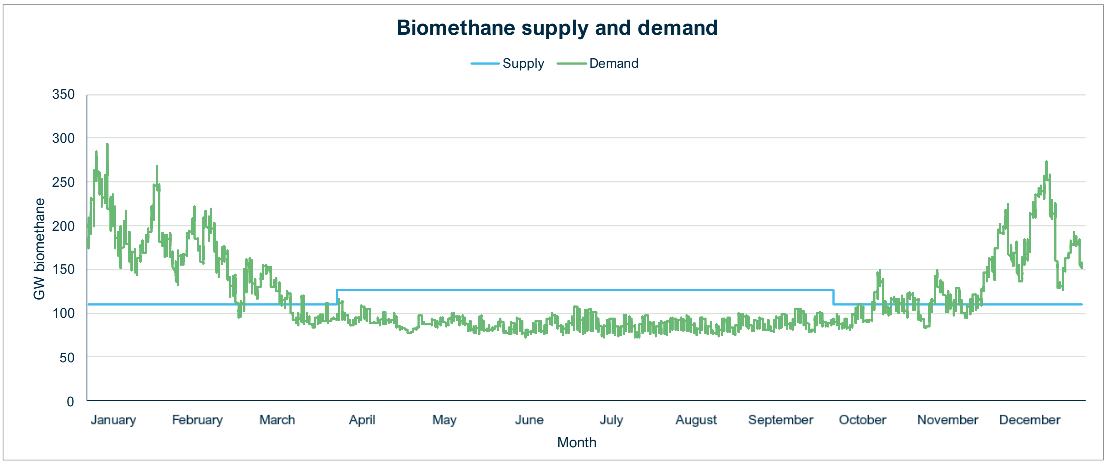


*Figure 1. Supply and demand profiles of biomethane in 2040, with a supply of 101bcm.*

[11] Storage volumes available in 2024 are 1,150 TWh, while withdrawal capacity is ~20 TWh/day. The withdrawal capacity in the EU of 20 TWh/day is 830 GW, assuming constant withdrawal for the 24 hours. AGSI database

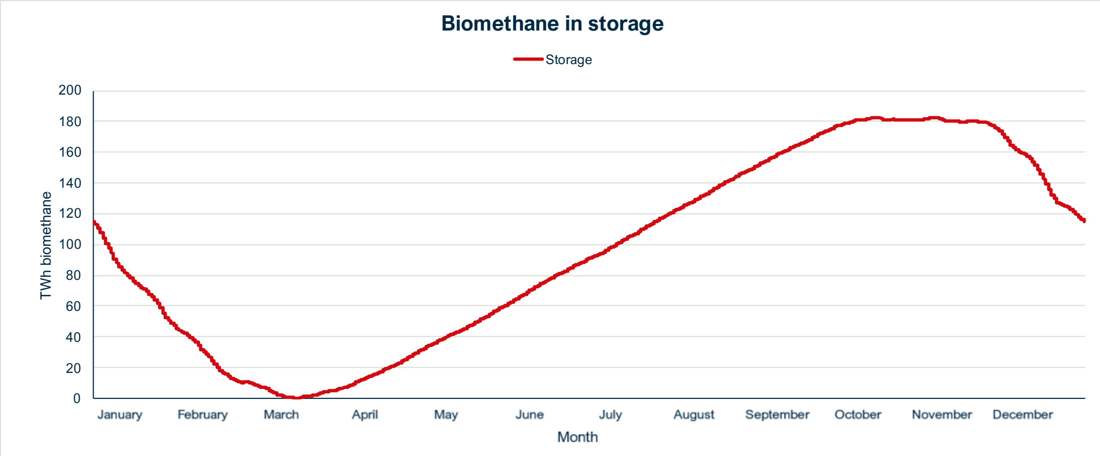


*Figure 2. The amount of biomethane in underground gas storage throughout the 2040 year*

## 2.4 Increasingly volatile gas demand leads to increased importance of withdrawal capacity

The ratio of peak withdrawal to storage volumes as such will change over time, with a peak withdrawal of 184 GW and volume of 183 TWh indicating approximately 1,000 hours of peak withdrawal needs. This ratio was very different in recent years, with more importance on storage volumes. In 2018, a year with significant use of gas storage, the peak withdrawal observed was 492 GW and the used storage volume was 915 TWh, indicating 2,120 hours of peak withdrawal needs were required. [12]

The increasing ratio of the required peak withdrawal from storage to the volume of storage required is a result of several factors.

Firstly, this is a result of an increasingly baseload demand for (bio)methane. In 2019, ~70% of methane was used in the built environment and power generation, where demand is mostly seasonal. In this analysis, using TYNDP NT+ scenario results and the built environment calculation, this is reduced to 57% following the increased baseload methane demands in trucking, shipping, the large increase in renewable generation and batteries in the power sector, and significant heat pump deployment in the built environment. While baseload use of biomethane can also be highly valuable in industry, and as a transport fuel for trucking and shipping, it does not require significant volumes of storage or a high withdrawal capacity to meet demand, thanks to the better match with the flat production profile of biomethane.

Secondly, notable shifts in the technology are expected in both the built environment and power generation sectors that will increase the “peakiness” of demand. As heating technologies in homes with a gas connection change[13], and variable renewable electricity generation production increases, gas demand will be reduced in parts of the year where there is low system stress. Gas remains a crucial energy source for these sectors however, especially in balancing periods such as when the system is under climatic stress. Where cold weather conditions result in high heating demands and reduced

[12] Peak withdrawal from storage since 2011 occurred in 2018 – and was 11.8 TWh/day or ~ 492 GW. Peak storage volume use annually since 2011 also occurred in 2018, using ~ 915 TWh. AGSI database

[13] See Appendix 1. For buildings with a gas connection today; 25% are expected to no longer use gas in 2040, one third of the remainder keep using condensing boilers, and two thirds of the remainder switch to a hybrid heat pump solution. No new gas connections are assumed.

efficiency of electric heat pumps, gas is used to efficiently provide heat. In "Dunkelflaute" moments with reduced variable renewable electricity generation, gas is ramped up rapidly to secure electricity supply. The demand profiles in Figure 3. show that while there still is a general seasonality to these demands, it is the peak moments where gas volumes are significant. The use of gas to supply energy in these stress moments is of very high value to society.

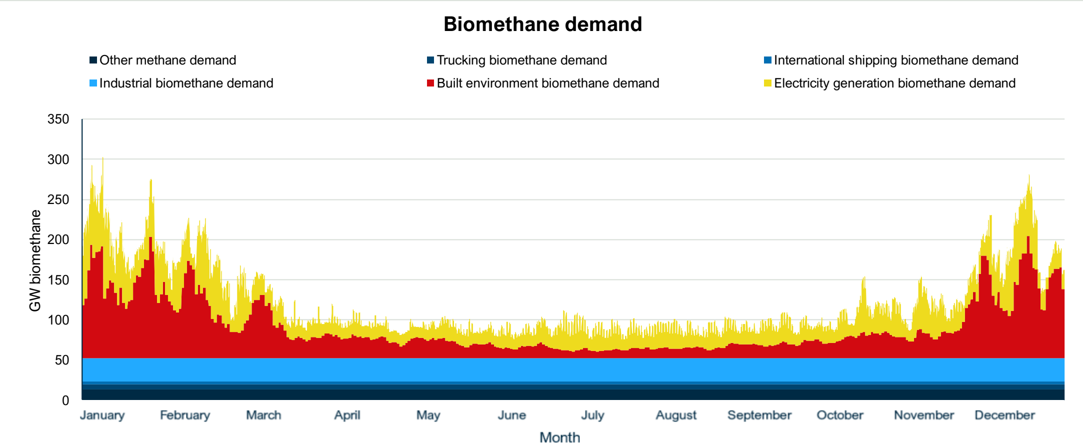


*Figure 3. The decomposition of biomethane demand in 2040*

## 2.5 High seasonality in energy demand in buildings with high storage need

In 2040, a significant technology switch is assumed for homes already connected to the gas grids. A quarter of these existing connections are assumed to no longer using gas by that time (e.g. by switching to alternatives, e.g. electric heat pump), one-third of the remainder are assumed to retain their condensing gas boilers, and two-thirds of the remainder switch to hybrid heat pumps. Despite this, the built environment is expected to remain the largest gas demand in 2040. Biomethane use in the built environment in 2040 when considering a '1-in-20-year' annual average temperature anomaly is 345 TWh.

As seen in Figure 4, ~80% of the gas demand for the built environment in 2040 comes in the winter hours, thus, significant storage volumes are required to enable biomethane use in the built environment. Also notable however is that this 2040 profile for heating has narrower peaks and a lower baseload compared to heating profiles today. This happens as a result of improved insulation in homes and the significant technology switch in space heating. For hybrid heat pumps it is assumed that gas provides 100% of the heat load when the ambient temperature is below -3°C, and 30% of heat load when ambient temperatures are between -3°C and 3°C.[14] This operational set up leads to increasing peakiness of demand.

With these assumptions total gas demand for the built environment reduces to 822 TWh in 2040, a 41% decrease compared to 2019[15]. The peak in daily gas demand does not decrease at the same rate, with

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[14] Assumption on operation mode and cut off temperatures made based on operation manuals of Daikin and Bosch and a European Heating Industry (2023) paper. (**Operation mode A**: >3°C ambient temperature – 100% Heat pump; **Operation mode B**: Between -3°C and 3°C ambient temperature – 30% boiler, 100% heat pump; **Operation mode C**: <-3°C ambient temperature – 100% boiler).

[15] 1,402 TWh in 2019 using ETM data found in the TYNDP 2024 as reference data.

the gas-only operation in the hybrid heat pumps at the lowest temperatures and the use of the remaining condensing boilers leading to a peak in biomethane demand of ~153 GW, and a peak total methane demand of 8.7 TWh/day, a 41% decrease from the 2018 peak gas demand.

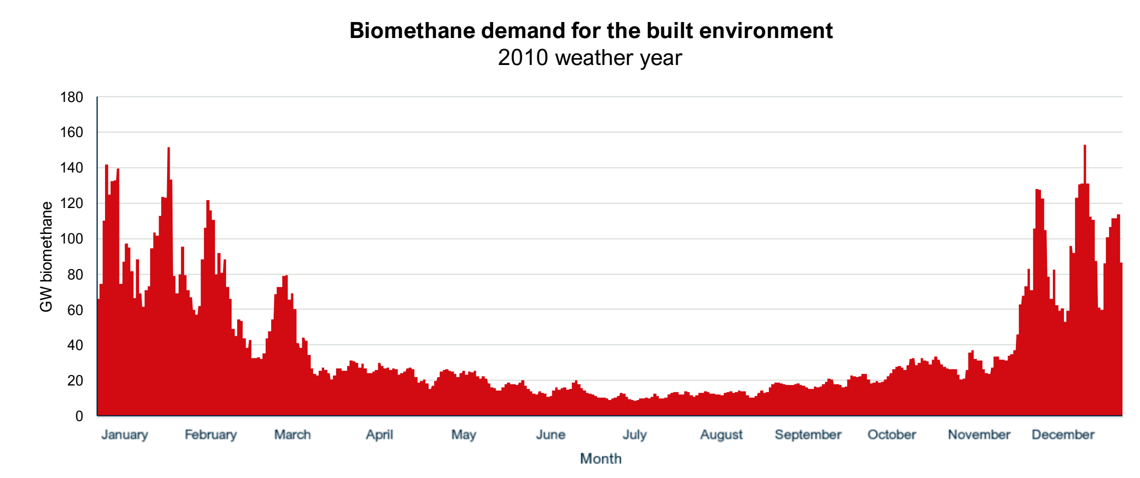


*Figure 4. Biomethane demand for the built environment in 2040*

## 2.6 Biomethane based power generation requires withdrawal from storages

In 2023, 436 TWh of electricity was generated from natural gas. TYNDP scenarios see a significant reduction in the use of methane for power generation in 2040, with Global Ambition and Distributed Energy scenarios having methane supply just 15 – 50 TWh of power, 0.4 – 1% of the total electricity production respectively. In the NT+ scenario it is 268 TWh, or 5%, requiring 649 TWh of methane. The NT+ scenario result is taken for this analysis.[16] Biomethane supplies 272 TWh of this methane demand in 2040.

Typically, flexible gas fired power generation occurs in moments of low variable renewable electricity generation, such as "Dunkelflautes". While more common in the winter, as solar output is notably reduced across the EU, these moments happen throughout the year. This is reflected in the seasonality of biomethane demand for power generation, with ~65% of demand coming in the winter hours. This seasonality is notably lower than the seasonality of the built environment. For power generation storage volume needs are thus of reduced importance compared to the built environment, however, withdrawal capacity is also crucial for power generation.

The value of methane use in power generation comes from its capacity, with large volumes available rapidly, this is seen in Figure 5. as significant peaks in demand for power generation can be seen throughout the year, with a peak demand of approximately 50 TWh biomethane in the summer hours only roughly half the size of the annual biomethane peak for power generation in the winter hours (111 TWh). In comparison the summer peak for the built environment is approximately 5 times lower than

[16] NT+ scenario taken as this scenario is deemed to have most realistic assumptions on the power generation side, see Appendix 1.

the winter hours peak. This is a notable factor determining the profile for biomethane storage, increasing the importance of withdrawal capacity.

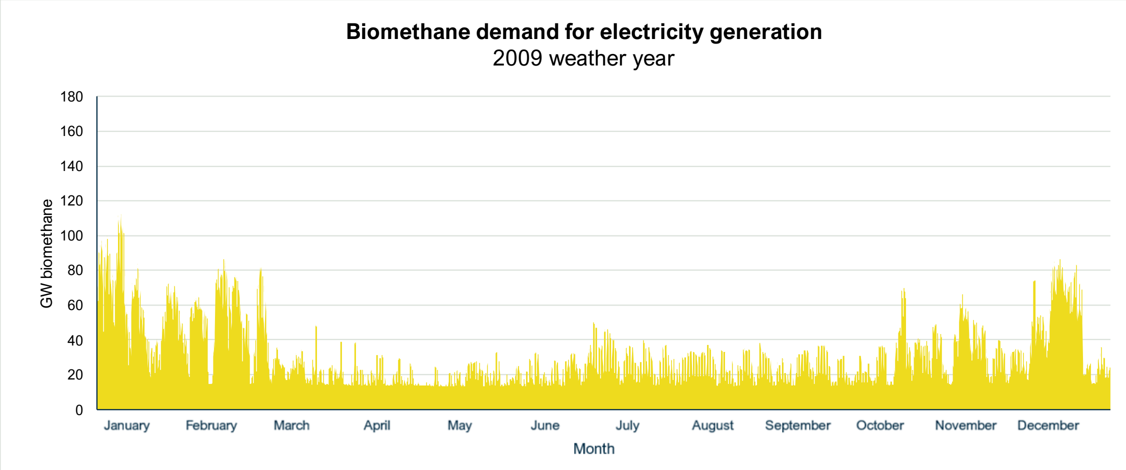


*Figure 5. Biomethane demand for electricity generation in 2040*

## 2.7 Baseload biomethane demands have a limited impact on EU storages

The remaining demands for biomethane (industry, international shipping, trucking, and other) [17] are simplified into baseload demands. These baseload demands are important for determining the total volumes of the biomethane use and other aspects of the infrastructure needed, such as pipeline capacity, however, as supply is above this baseload demand for simplicity assumes that these demands do not trigger the need for storage. Figure 6 shows the hourly baseload demand for biomethane in 2040, which is significantly below the levels of supply in both summer and winter periods.

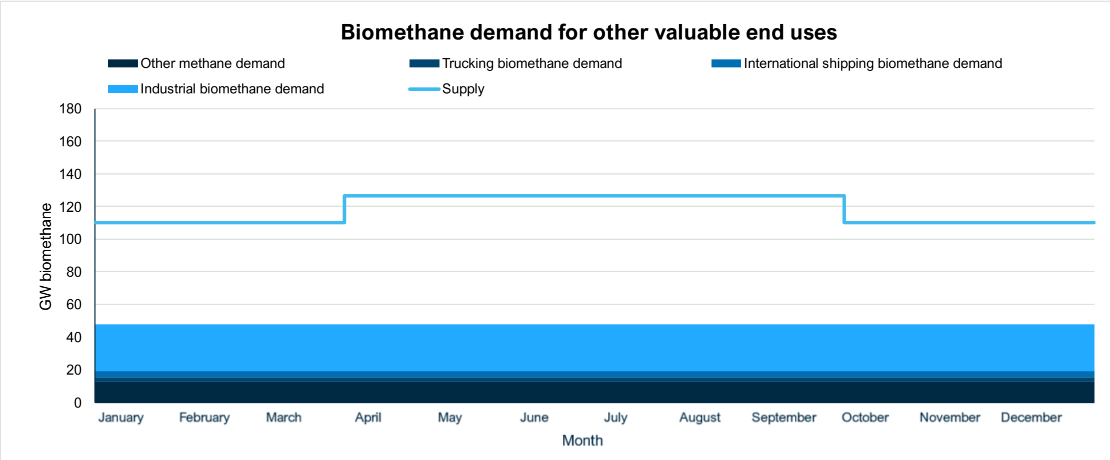


*Figure 6. The baseload demands for biomethane and biomethane supply in 2040.*

[17] 'Other methane demand' is taken from TYNDP NT scenario to allow our results match the methane share across end uses. This category includes agriculture, SMRs, and non-energy uses of biomethane, with a demand in 2040 of 16 TWh, 134 TWh, and 114 TWh of methane respectively.

# 3. Future use of pipelines for biomethane

## 3.1 Aim and overall results

The aim of this chapter is to estimate the biomethane demand and corresponding pipeline capacity needs for different regions across the EU in 2040. By using a set of archetypes, based on real-life examples, the analysis explores the need for gas infrastructure by considering four different EU regions of ~8,000 km² (a circle with a radius of 50 km). Each region is characterised by its supply potential, gas use in the built environment, gas powered electricity generation, industrial gas demand, and the presence of ports with LNG bunkering.

Gas pipelines transport natural gas and some biomethane already and will transport increasing volumes of biomethane and e-methane in the future while natural gas transport will decrease. From the total mix of natural gas, biomethane and e-methane transported through pipelines in 2040, the analysis in this chapter focuses on pipeline needs to enable biomethane use in the five valuable end uses discussed in the introduction (buildings, industry, electricity production, international shipping and heavy road truck transport). The key findings from this analysis are highlighted below:

**High-demand regions in the EU will require significant shares of the existing pipeline capacity to handle peaks in demand.**
In regions with substantial demand for biomethane, particularly those with high gas use in heating and industrial processes, pipeline capacity will need to be robust to handle peak demand periods (up to 8.9 GW in the analysed archetypes). This is mainly driven by the peaks in biomethane demand for heating in the built environment during winter months and gas-fired power generation during periods with low renewable energy production. In particular, spikes in residential heating demand have a significant impact on required pipeline capacity.

**Net demand regions likely need extensive infrastructure to source additional biomethane to meet the regional demand.**
Regions with high biomethane demand will not be able to source their supply needs locally. The analysis shows that net demand regions analysed in this section may need to source biomethane from regions 5.8 to 8.4 times their own size. In combination with additional demand in neighbouring regions, long-distance transfers and extensive pipeline networks will be needed to secure biomethane supply.

**Net supply regions will require significant pipeline length to transport their relatively baseload production of biomethane to demand areas and storages.**
In contrast to demand regions, net supply regions will likely have more stable transport needs for biomethane as biomethane production profiles are relatively stable throughout the year. While their pipeline needs are not too sensitive to peaks in production or supply, they will still require extensive networks to transport biomethane to customers in broader areas. These net supply regions will function as key suppliers to demand-heavy areas, ensuring steady biomethane flows across the EU.

## 3.2 Brief description of assessment methodology

This section provides a brief description of the methodology used to assess pipeline needs for the use of biomethane in valuable end uses. Details on sources, assumptions and calculations are provided in Appendix 2. This analysis of pipeline for typical EU locations uses four archetypes to assess the annual and hourly balance of biomethane supply and demand. The archetypes are inspired by real-world locations. Each archetype is a circular area with a radius of 50 km. This analysis offers new insights in infrastructure needs for biomethane transport and storage to match regional demand and supply in 2040.

- **Archetype 1: High Demand and Supply region.** This archetype has high biomethane demand driven by space heating, electricity generation, industry, and a large port with LNG bunkering. It also has significant supply potential from agricultural and urban waste sources. Examples of these regions can be found in Northwest Europe.
- **Archetype 2: Industrial Gas Demand region.** This region is characterised by a high industrial gas demand, moderate electricity generation, little residential gas use, and a medium-sized port with LNG bunkering. Examples of such regions can be found in France, Spain and Italy.
- **Archetype 3: Electricity Production-Focused region.** This region has significant gas-fired electricity production and industrial methane use, particularly used for emission reduction in primary steelmaking. Residential gas demand is present but not dominant. This region is inland, so no bunkering occurs here. Such regions can be found in central and eastern Europe.
- **Archetype 4: Net Supply region.** A rural area with significant agricultural land, providing strong biomethane production potential. Demand across all sectors is low, mainly from the built environment, positioning the region as a net supplier to others. Examples of this archetype can be found in rural regions, e.g. in Sweden and Romania.

**Estimating supply and demand**

For each archetype, the biomethane supply potential was estimated by analysing the share of agricultural, urban, and forestry areas in the region. Supply density was determined by dividing national biomethane production potentials for 2040[18] by the national area of relevant land types for biomethane production feedstocks (i.e. agricultural land for anaerobic digestion, urban and forestry areas for gasification).

On the demand side, we assessed gas use in key sectors:

- *Built environment:* Estimated based on the 2040 national built environment gas demand calculated per country in Chapter 2 and the population in the region.
- *Electricity generation:* Derived from the TYNDP NT+ scenario country data for 2040, using the current share of national gas-fired powerplant capacity in the region.
- *Industrial demand:* Estimated based on current methane use in industry and expected developments by 2040 in the TYNDP NT+ scenario, accounting for potential new uses for methane like steel production.
- *Shipping:* Estimated using current bunkering data and projections on developments methane use in maritime bunkering towards 2040 in the TYNDP NT+ scenario.

[18] Guidehouse (2024). *Biogases towards 2040 and beyond*. [Link]

- *Trucking:* Estimated based on existing CNG/LNG stations, national transport data, and TYNDP NT+ scenario expectations for the development of methane in trucking.

**Pipeline and storage needs**

For each archetype, we estimated the mismatch between annual supply and demand volumes to gain insights into the supply or demand area required to address supply shortages or handle supply surpluses. Additionally, we calculated the pipeline capacity needed to meet peak demand or supply, based on demand and supply profiles. Seasonal variations were also considered to assess storage needs. This analysis offers a comprehensive understanding of the infrastructure required to maintain a stable biomethane supply for these regions by 2040.

## 3.3 Pipeline capacity needs in a High Demand and Supply region

This archetype region has a high demand for biomethane, with significant consumption of gas in various sectors, in combination with a substantial potential for biomethane supply. Currently, around 80% of the heating demand in the built environment is met with natural gas, and it is assumed that a large proportion of homes will adopt hybrid heating solutions by 2040, maintaining substantial methane consumption in the residential sector.[19] The region is home to a large industrial cluster and has significant installed capacity for gas-fired electricity generation. Additionally, the presence of a major port, which accounts for approximately 25% of the EU's total maritime bunkering demand, along with biomethane demand from heavy-duty transport, contributes to the region's substantial overall biomethane needs.

The region also boasts a considerable potential for supply. Approximately 45% of the land is dedicated to agriculture, offering significant feedstock for biomethane production through anaerobic digestion. Moreover, the region contains half of the country's urban area, making municipal solid waste a significant resource for biomethane production through thermal gasification.

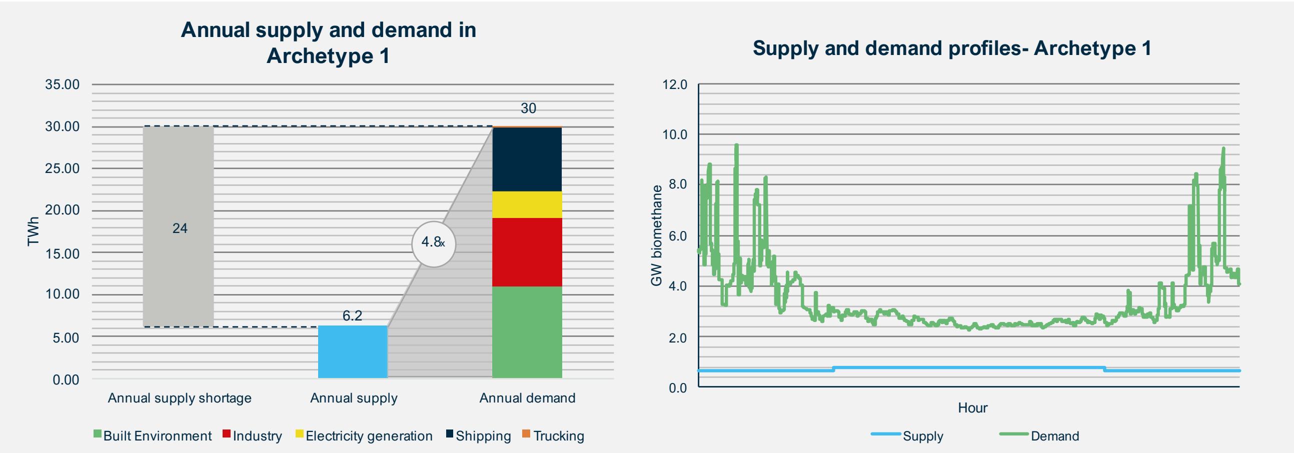


*Figure 7. Annual demand and supply volumes (left graph) and profiles (right graph) for biomethane in a high demand and supply region.*

Despite the local advantages for biomethane supply, the region's annual biomethane demand is estimated to be 4.8 times larger than its local supply potential, providing insights into the required

[19] See Appendix 1 for assumptions on the heating technology transition in gas connected homes

sourcing region. This is without factoring in potential competition with the neighbouring regions' biomethane needs, which would further expand the required sourcing circle.

To accommodate the archetype region's energy demands, particularly during peak periods, substantial pipeline capacity is essential. During the winter months, the region experiences demand peaks up to 9.6 GW, driven by high residential heating demand (6.6 GW), a simultaneous peak of 1.2 GW from gas-fuelled power generation, and a consistent 1.8 GW baseload demand from industry, shipping and truck transport. In contrast, local biomethane supply during these peak winter periods is only around 0.8 GW, creating a significant supply-demand gap of 8.9 GW.[20] This shortfall will need to be addressed through deliveries from other regions, likely supported by gas storage facilities, to ensure reliability during peak periods. The nearest storage facility is located about 50 km outside the region. Addressing the peak supply shortfall with gas from outside the region would require a pipeline system capable of handling these peak volumes of 8.9 GW, which would fall within the capacity range of gas transmission pipelines. On top of that, other methane volumes and transit flows need to be handled.

In summary, this archetype illustrates the challenge of balancing high demand with limited local supply potential, requiring sourcing from a large area and robust pipeline infrastructure to meet peak net demand.

## 3.4 Pipeline capacity needs in an Industrial Gas Demand-focused region

This archetype region has a high demand characterised primarily by its industrial activities and gas-fired electricity generation. The region is home to a large industrial cluster, including sectors such as ceramics production, fertiliser production and refinery, which require significant amounts of methane for their high temperature production processes and hydrogen needs. Additionally, the region holds 9% of the national installed capacity of gas-fired electricity generation, a medium-sized port representing ~3% of the EU's current maritime bunkering demand, and moderate methane consumption in heavy-duty transport. The built environment in this region contributes relatively little to methane demand, with only 25% of heating needs currently met by natural gas, with a further reduction assumed towards 2040.

In terms of supply, the region has relatively low potential for biomethane production. There is significant agricultural land in the area - approximately 55% of the land – but the national supply density from agricultural areas is relatively low. Additionally, there is a moderate urban and forestry area that can supply organic waste and residues for thermal gasification.

[20] Study results are rounded to 1 decimal place.

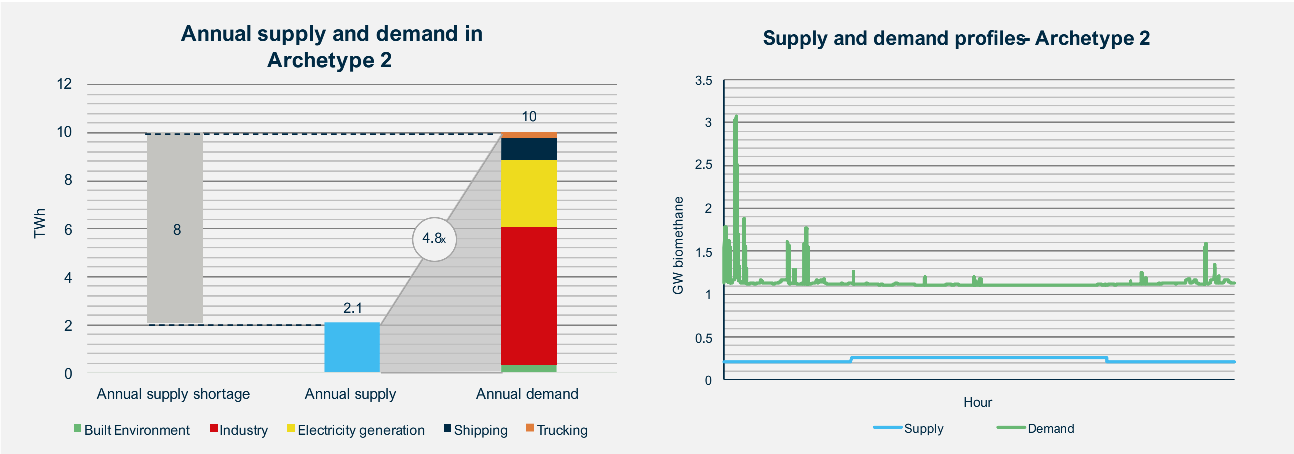


*Figure 8. Annual demand and supply volumes (left graph) and profiles (right graph) for biomethane in an industrial gas demand-focused region.*

Based on the archetype's supply and demand potential outlined above, the region is estimated to have an annual shortfall of approximately 8 TWh. To be able to meet the region's demand, the supply area should be 4.8 times the size of the current area, without accounting for competition in biomethane demand from neighbouring regions.

To meet its energy needs during peak periods, particularly in the winter months, the region will require substantial pipeline capacity. Biomethane demand peaks at 3.1 GW in winter, driven primarily by nearly 2.2 GW of peak demand for electricity generation and a consistent 0.8 GW baseload from industry, shipping and trucking. In contrast, the impact of heating of buildings on demand peaks is relatively minor, contributing only 0.2 GW at peak. Local biomethane supply during these peak periods is only about 0.2 GW, leaving a gap of 3 GW that will need to be filled through deliveries from other regions, likely supported by storage solutions. The nearest storage facility is located about 150 km outside the region. Addressing this peak supply shortfall with gas of 3 GW from external supply or storage, along with addressing needs in other methane needs and transit, would require a notable pipeline capacity, typically aligned with methane transmission pipelines. Outside the peak demand periods, the pipeline system is required to address daily shortfalls in regional supply.

In summary, this archetype faces significant challenges in balancing high industrial and electricity demands with limited local biomethane supply. The region will rely heavily on supply from external regions, requiring an extensive sourcing network and strong pipeline infrastructure to manage peak seasonal demand.

## 3.5 Pipeline capacity needs in an Electricity Production-Focused region

This archetype represents a region with high methane demand, primarily driven by industrial consumption. The most significant contribution to industrial demand comes from a steel plant, which is assumed to transition from its current coal-based blast furnace production process to a DRI (Direct Reduction of Iron) process using natural gas and increasingly biomethane towards 2040. In addition to industrial demand, the region represents 15% of the national gas-fired electricity generation capacity estimated to run at high full load hours in the National Trends scenario of TYDNP 2024. Finally, there is also some consumption of methane in heavy-duty transport and the built environment.

On the supply side, the region has reasonable potential for biomethane production. Approximately 40% of the land is agricultural, providing feedstock for anaerobic digestion, while another 15% of the land is urban, and 35% is forestry, both of which offer significant feedstock for gasification. Despite this supply potential, the local biomethane production remains insufficient to meet the region's high demand.

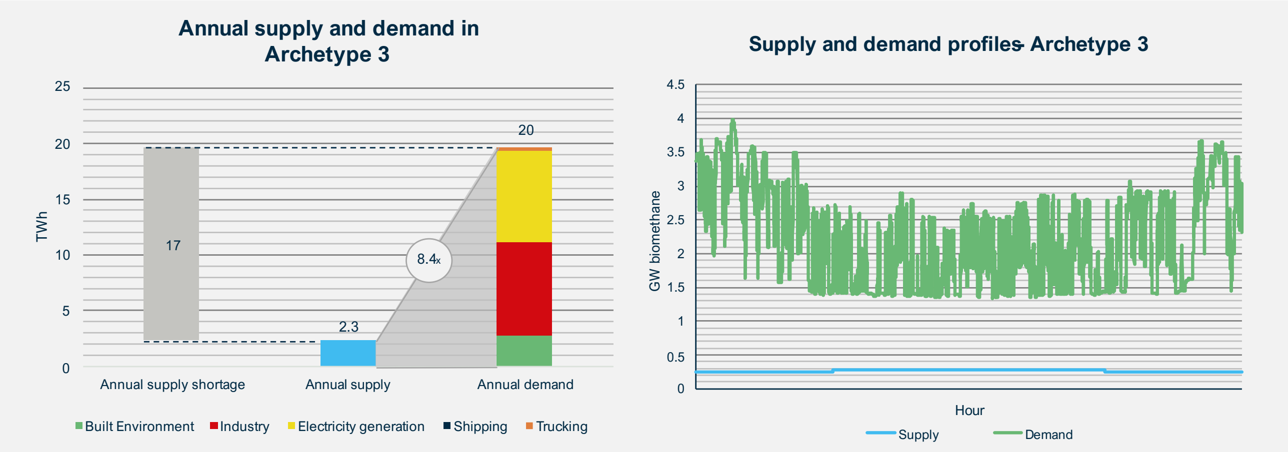


*Figure 9. Annual demand and supply volumes (left graph) and profiles (right graph) for biomethane in an electricity production-focused region.*

Based on the archetype's supply and demand potential outlined above, the region is estimated to have an annual shortfall of approximately 17 TWh. To be able to cover the full demand, the supply area should be 8.4 times the size of the current area, without accounting for any competing biomethane demand in surrounding regions.

To meet energy demand, especially during peaks in the winter months, the region requires a significant capacity of pipeline infrastructure into the region, likely supported by gas storage solutions. Demand peaks are expected be 4 GW in winter, with the built environment contributing 1.3 GW during cold months. Gas demand for power production sees many peaks throughout the year, reaching up to 1.7 GW, while the industrial sector and trucking provide a steady baseload demand of approximately 1 GW. The local biomethane supply capacity during these peak periods is only around 0.3 GW, resulting in a peak supply-demand gap of 3.7 GW. This gap will need to be filled by deliveries from other regions, and likely supported by storage facilities. The peak supply needs 3 GW, when considered alongside the needs for other methane needs and transit requirements, would require a pipeline capacity within the range of gas transmission pipelines.

In summary, this electricity production-focused region faces significant biomethane supply challenges, requiring sourcing from a large area and infrastructure upgrades to manage peak demand periods effectively.

## 3.6 Pipeline capacity needs in a Net Supply region

This archetype represents a low-demand, rural inland region with a sparse population and minimal industrial activity. The region has no electricity generation and very little transportation demand, with only a few roads crossing through. Biomethane demand is minimal across all sectors. While the region has a significant agricultural area—about 80% of the land—the overall production density is not as high in other analysed regions. This is due to the structure of the agriculture in the country, which limits feedstock yield for anaerobic digestion. Additionally, the absence of urban regions and forestry areas means there is no feedstock available for biomethane production through thermal gasification. Despite this, the biomethane supply potential remains significantly higher than local demand.

The annual supply of biomethane in the region is estimated to exceed local demand by approximately 1.5 TWh. This surplus can be exported to other regions, supplying a demand ~4 times the demand in of the region, providing insight in the required extensiveness of the network to distribute the supply potential. This is without taking into account if neighbouring regions are net supply regions as well.

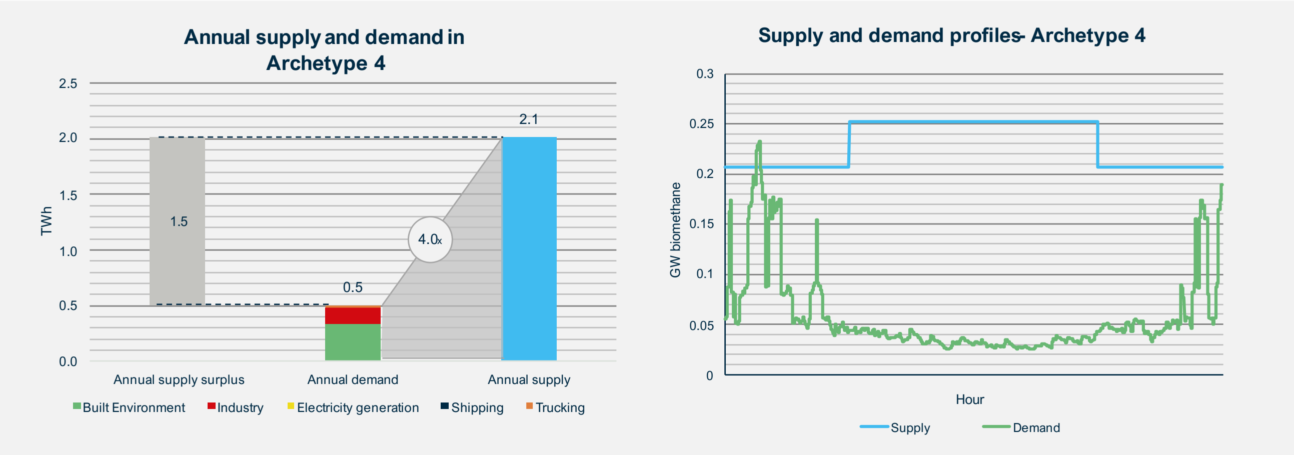


*Figure 10. Annual demand and supply volumes (left graph) and profiles (right graph) for biomethane in a net-supply region.*

Despite this annual surplus, there is one moment during the year where local demand slightly exceeds supply, requiring either supply from other regions or the use of nearby storage, located around 50 km outside the region.

The biomethane supply is relatively stable throughout the year, with a slight increase during the summer months, reaching up to 0.25 GW. While there is one instance where biomethane demand temporarily surpasses supply, the peak remains below the higher summer supply levels. Given the stable supply and low demand, existing transmission pipeline infrastructure in the region appears sufficient to handle transporting any surplus biomethane to neighbouring regions, with a peak of 0.2 GW biomethane. However, the actual pipeline capacity required should be assessed in the context of broader methane demand and transit needs. Importantly, while the peak transport capacity needs for biomethane are low here, existing and new gas infrastructure in the region are crucial for biomethane, as they enable transport to different regions and to storages, enabling emission reductions elsewhere.

This archetype illustrates the potential of rural, agricultural regions to act as net suppliers of biomethane, transporting surplus energy to surrounding areas while maintaining stable local supply profiles.

## 3.7 Comparing the results of all analysed archetype regions

Our analysis indicates a need for extensive pipeline infrastructure by 2040 to support the use of biomethane. A key finding is the spatial disconnect between the dispersed biomethane supply regions and large, concentrated demand centres. Even within areas of 8,000 km², the demand for biomethane exceeds regional production by 5 to 8 times. This underscores the need for extensive pipeline networks required to bridge the gap between supply and demand. In fact, the identified supply-demand ratio's likely understates the scale of the sourcing areas required, as multiple demand centres will likely compete for biomethane within the required sourcing area for just one of them.

**Supply and Demand Mismatch**

Our Net Supply archetype reveals that even in regions with low biomethane demand, the excess supply is substantially lower than the over-demand in other archetypes. For instance, in this rural net supply region, the annual oversupply of biomethane is about 1.5 TWh, which pales in comparison to the 8–24 TWh of over-demand in the other archetype regions. This significant imbalance underscores the necessity for an extensive EU pipeline network capable of connecting multiple low-supply regions to major demand centres.

**Peak Demand and Pipeline Capacity**

The pipeline capacity required to satisfy peak biomethane demand is substantial. Peak transport capacity needs to the region range from 2.7 to 8.9 GW, which represents 20–60% of the capacity of a typical 24-inch diameter pipeline. Importantly, this value excludes the remaining 59% of the methane demand required to meet total gas needs during peak times. Additionally, it does not account for the capacity needed to transport gas to other areas across the EU or for storage, both of which are critical services and will increase the pipeline capacity needs.

**The Role of Storage and Infrastructure Links**

In all archetypes, including the Net Supply region, storage and infrastructure links to other demand centres are both essential to meet peak demand moments. Gas infrastructure must support these peaks through interconnected pipeline grids and access to storage solutions. These systems not only help cover short-term spikes in demand but also provide a means to efficiently use surplus biomethane throughout the year.

**End Use and Seasonal Demand Variations**

Additionally, the role of electricity generation varies across archetypes. In the first two archetype regions, gas is primarily used for dispatchable power during peak moments, mostly in winter. The Electricity-Production focussed region, however, involves more consistent use of gas-fired power plants throughout the year as part of its generation mix, with peak demand occurring in both summer and winter, leading to higher full-load hours of the pipeline to the outside world.

# 4. Sensitivity: Modest scale up of biomethane

This chapter describes the outcomes of a sensitivity analysis on the supply of biomethane in 2040. The main conclusion remains the same in this analysis, showing that infrastructure will remain crucial in 2040 even if supply of biomethane is slower to scale up. This analysis explores the impact of a more conservative biomethane production potential for 2040, aligned with the TYNDP NT+ estimate of 72 bcm, compared to the base case of 101 bcm. The reduced increase in biomethane production is assumed to primarily reflect lower contributions from sequential cropping and thermal gasification, both of which are currently still in early stages of development. A reduced scale-up of biomethane supply leads to a lower need for storage volume and a lower peak withdrawal capacity for biomethane specifically but isn't assumed to impact the total methane storage needs, with natural gas assumed to replace biomethane. This scenario also impacts pipeline transport capacity needed for biomethane, with a reduction in peak transport needs across all archetype regions. However, when looking at the required extensiveness of the gas grid to source biomethane, it is noted that biomethane transport from farther afield is needed in two of the demand regions. These regions have a relatively high share of sequential cropping and gasification in the base-scenario, so with a reduced supply in this analysis there is an increased need for biomethane shipments to the region from neighbouring supply areas.

*Table 3. Comparison of main characteristics analysed in sensitivity analyses.*

| **Main characteristics analysed** | | **Base case** | **TYNDP supply** |
|---|---|---|---|
| Storage volume need | *TWh* | 183 | 132 |
| Peak withdrawal needs | *GW* | 184 | 131 |
| Range of peak pipeline capacity needs in net demand archetypes | *GW* | 2.9 – 8.9 | 2.0 – 6.3 |
| Demand-supply ratio in net demand archetypes | - | 4.8 – 8.4 | 4.3 – 10.4 |

The base case for this study assumes a biomethane production potential in Europe of 101 bcm, based on the full potential estimates from a recent study for the European Biogas Association (EBA) performed by Guidehouse (2024). These estimates are based on available feedstocks, taking into account technical and sustainability constraints. In addition, the sustainable feedstock potential is reduced to consider existing non-energy uses. However, the achievement of this full potential in 2040 is not reflected in the TYNDP 2024 NT+ scenario. Several factors may cause this reduced supply compared to the total potential, such as competition for feedstocks from other energy uses and technological bottlenecks. To account for these potential limitations, it is relevant to explore the implications of a reduced biomethane supply scenario.

This sensitivity analysis adjusts the supply potential in line with the TYNDP NT + scenario estimate for 2040, which forecasts a domestic biomethane production potential of 72 bcm (767 TWh). This scenario thus reflects a 29 bcm lower scale-up of biomethane compared to the base case.

The reduced biomethane supply in this sensitivity analysis is primarily reflected by lower contributions from two key sources: sequential cropping and thermal gasification. Both of these biomethane (production) sources production are relatively in early stages of development, making it relevant to explore a more conservative deployment. The supply from these two biomethane sources was adjusted as follows:

- **Sequential Cropping:** The EU-production potential from sequential crops is reduced by 15 bcm (-51%), resulting in a production potential of 14 bcm - compared to 29 bcm in the base scenario.
- **Gasification:** The EU-wide production potential from thermal gasification is reduced by 14 bcm (-42%), leading to a production potential of 19 bcm - compared to 33 bcm in the base scenario.

These adjustments were applied at the EU level and to the relevant archetypes based on the feedstock mix in each country.

The total demand for methane was assumed to remain unchanged, meaning that reduction of biomethane supply is compensated by an increase in other methane sources. The share of biomethane in the methane grid is thus lower than in the base-scenario using the EBA supply potential, decreasing from 41% to 29%. The demand for biomethane is matched to the lowered supply potential.

***Changes in biomethane storage needs***

The reduction in biomethane supply significantly impacts the storage volume and peak withdrawal capacity needed for biomethane in the system (see Table 4). In the base case, the total storage volume required for biomethane was 183 TWh, but this decreases to 132 TWh (-28%) under the reduced supply scenario. Similarly, the peak withdrawal capacity for biomethane drops from 184 GW to 131 GW (-29%).

*Table 4. Overview of main characteristics on (bio)methane storage needs in the base scenario with a EU biomethane potential of 101 bcm and a scenario with a reduced biomethane potential of 72 bcm.*

| Main characteristics analysed | | EBA potential (base case) | TYNDP supply potential |
|---|---|---|---|
| Storage volume need | *TWh* | 183 | 132 |
| Peak withdrawal needs | *GW* | 184 | 131 |

***Changes in biomethane pipeline needs***

The sensitivity analysis reveals that a lower biomethane supply alters the pipeline needs differently across the archetypes, mainly depending on differences in changes in the ratio between supply and demand for each region (see Table 5). This is a result of a difference in the change the production of biomethane across the analysed regions. The High Supply and Demand region, already has a relatively low share of biomethane production from sequential cropping and gasification. As a result, the supply reduction in this region is less significant than for the other two demand regions. In the demand regions with more significant supply reductions the ratio between demand and supply increases, indicating that larger sourcing areas would likely be required to meet the demand in that area.

The lower biomethane supply potential cause the peak in transport capacity to drop by ~30% in all archetypes. The peak transport capacity need in these regions is determine largely by the demand for biomethane, which decreases as a result or the lower share of biomethane in the methane grid. The transport capacity needs for the net supply region for delivering biomethane to other regions is 24% lower because of the lower supply potential in the region.

*Table 5. Overview of main characteristics on biomethane pipeline needs in archetypes in the base scenario with a EU biomethane potential of 101 bcm and a scenario with a reduced biomethane potential of 72 bcm.*

| | | Archetypes | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | High supply and demand | | Industrial gas demand | | Electricity Production-Focused | | Net supply region | |
| **Main characteristics analysed** | | **EBA** | **TYNDP** | **EBA** | **TYNDP** | **EBA** | **TYNDP** | **EBA** | **TYNDP** |
| Annual biomethane supply | *TWh* | 6.2 | 5.0 | 2.1 | 1.4 | 2.3 | 1.3 | 2.0 | 1.5 |
| Annual biomethane demand | *TWh* | 30.0 | 21.2 | 10.0 | 7.1 | 19.7 | 13.9 | 0.5 | 0.4 |
| Biomethane demand vs. supply | - | 4.8 | 4.3 | 4.8 | 5.0 | 8.4 | 10.4 | 0.3 | 0.2 |
| Peak capacity for biomethane import/export | *GW* | 8.9 | 6.3 | 2.9 | 2.0 | 3.7 | 2.7 | 0.2 | 0.2 |

# 5. Cost competitiveness of gas infrastructure

## 5.1 Aim and overall results

The EU has 260,000 kilometres of gas transmission infrastructure, around 150 underground gas storages and 33 LNG terminals. This infrastructure is used today to import, transport, and store around 350 bcm of natural gas. This chapter aims to provide an initial cost estimate of maintaining the gas grids to enable the transport of the assumed 240 bcm of gas in 2040, including significant volumes of biomethane.

**Enabling biomethane in 2040 requires investments into gas grids of € 2.5 billion/year**
First estimates indicate investments in the gas grid for biomethane are € 2.5 billion/year. The majority of this investment is in new connections to transmission and distribution grids (€ 1.7 billion/year), with some of this investment commonly shared with plant operators. Reverse flow stations (€ 0.6 billion/year) are another important investment in gas grids to enable the flow of biomethane from low pressure grids to high pressure grids, enabling transmission to other demand regions and storage. Lastly, the low pressure distribution network will require reinforcement (€ 0.2 billion/year) to enable biomethane supply to be shared over more demand on a local level. These reported investments for the gas grid will be split between the biomethane producers and the gas grid operators depending on the investment type and country.[21] As a simplification, this study calculates the total investment need, leading to an overestimation of the cost to gas grid operators in 2040.

**Integrating biomethane into the gas grid requires a 40 times lower annual investment than the electricity grid up to 2040.**
When comparing this with the required investments in the electricity grid it is clear that gas grids offer a real opportunity for cost efficient energy transport in the future. Eurelectric have estimated an investment need of € 67 billion/year to 2050 for the electricity distribution grids alone, [22] while ENTSO-E have estimated an investment need of at least € 33 billion/year to 2050 for the electricity transmission grids.[23] The total €100 billion/year is a factor of 40 higher than the € 2.5 billion/year required for the gas grid, while these investments enable only 4 - 5 times the renewable energy come online, with a 2040 electricity demand of 4,000 – 5,000 TWh compared to 1,035 TWh of biomethane.

**Even with reduced volumes, the total cost of operating the gas grid will remain low in 2040**
The cost of gas grid operation today is approximately € 3.70/MWh. Several factors will influence how this develops to 2040. As the transported volumes decrease in 2040, this will have an upwards effect on the tariff. Additionally, any changes to the depreciation period of the assets as a result of this will also have an increasing effect on the tariff. However, with this decrease in transported volumes in 2040, volume related operational costs will decrease. By 2040, the current regulated asset base will be increasingly depreciated as well, and some assets will be transferred to the hydrogen regulated asset base, both having a downward effect on the future tariff. With these opposite effects it can be fair to

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[21] Biomethane Industrial Partnership (2024). *Optimising the cost of biomethane grid injection*. [Link]
[22] Eurelectric (2024). *Grids for Speed.* [Link]
[23] € 834 billion by 2050, assumed to have even annual split of investment. ENTSO-E (2024). *Regulatory systems of EU Electricity Transmission System Operators need to be adapted to ensure that the massive grid transmission investment plans can be financed.* [Link]

assume that the 2040 tariff for maintaining the current transmission grid will stay relatively similar to the tariff today. As such, maintaining the transmission network in 2040 provides a very cost-effective option for enabling emission reduction across Europe.

*Table 6. Overview of the annual cost of new investments required into gas and electricity infrastructure by 2040*

| New investments | | Gas grids | Electricity grids |
|---|---|---|---|
| ***Connection costs*** *(low & high pressure grids)* | *€ billion/year* | 1.7 | - |
| ***Reinforcement costs*** | *€ billion/year* | 0.2 | - |
| ***Reverse compression costs*** | *€ billion/year* | 0.6 | - |
| **Total cost of new investments** | *€ billion/year* | 2.5 | 100 |

## 5.2 Brief description of assessment methodology and reading guide

To assess the cost of the gas grid in 2040, the cost of required investments in the grid are considered alongside the cost of maintaining the current gas grid. To give a complete estimate of the cost, both the distribution and transmission grids are considered. All costs considered are currently split in different proportions between the biomethane plant producer, the gas grid operator, and other gas grid users depending on the country. [24] As a simplification, the full cost is calculated in this study. In reality this will not be the cost to the grid operators and grid users. For a full methodology see Appendix 4.

**New investments into the gas grid to enable largescale biomethane use**
Small modifications to the existing gas grid will be required to bring large volumes of biomethane into the grid. These modifications can fall under three categories: grid connections, grid reinforcement, and reverse compression stations.

<u>Grid connections</u>
The grid that a biomethane plant connects to is chosen as a result of an economic optimisation done by the distribution and transmission operators together. This methodology leads to different splits of plant distribution per country depending on the grid topology and the location of the connection request. This analysis assumes 65% of AD plants connect to the distribution grid and 25% of AD plants to the transmission grid in 2040, with the final 10% not having a direct grid connection.[25] This largely reflects

[24] Biomethane Industrial Partnership (2024). *Optimising the cost of biomethane grid injection*. [Link]
[25] Of this 10%, 5% is assumed to be transported and used as bio-CNG/bio-LNG, while the other 5% is assumed to be injected into the transmission grid via a central injection point.

the EU average split between distribution and transmission grid connected plants today, though some countries have very different splits.[26]

Gasification plants, with a much higher capacity than most AD plants, are all assumed to connect to the transmission grid. Economies of scale in the cost of grid connection are likely, however, due to a lack of data this effect cannot be included in this study. [27]

The cost of connection to both gas grids was provided by GIE members and includes the compression of the biomethane to network pressure, the 'last mile' pipeline to the main network, and the grid injection station. The main difference in cost of connections between the networks comes from compression requirements.

Grid reinforcement

Grid reinforcement, similar to the concept of grid meshing for power, connects local distribution grids together to create a new larger grid with increased demand, allowing biomethane supply to continue unobstructed. This is typically one distribution pipeline connecting two grids and is often the lowest-cost grid upgrade to enable more volumes of biomethane to enter the grid. This is included in this analysis using GIE member data on how often the distribution grid needs reinforcement per biomethane plant connected, and the typical cost of such a pipeline segment.

Grid reinforcement is however limited by the availability of other suitable grids in the area and the fact that in the future, due to growing regional production of biomethane, the transmission of locally produced gas to other regions and storages will be required.

Reverse compression

Reverse compression stations are built at the transfer station, where the distribution and transmission grids are connected, allowing for the compression of gas from the lower pressure distribution grid up to the transmission grid. These stations are modular units, with the compressor a large share of the total cost. GIE member data provides details on the capital and operational cost of reverse compression stations and estimates how many reverse compression stations are needed per distribution grid connected biomethane facility.

**Comparing the costs of the gas grid to the costs of the electricity grid**

The cost of maintaining and improving the gas grid to handle large volumes of biomethane in the future must be considered in the context of the cost of other infrastructure developments to enable emission reduction, such as the development of the electricity grid. Recent EU-wide estimates for the investments required to develop the electricity grid up to 2040 are taken from European associations to give an indication of the total investment required. Indications of the total volumes of electricity in the system in 2040 are taken from the same sources/authors.

[26] EBA (2024). *From plant to grid: navigating biomethane injection*. [Link] – Italy is an example of where the majority of biomethane plants connect to the TSO grid instead of the DSO grid as a result of the connection cost optimisation step.

[27] This study assumes that 65% of anaerobic digestion plants connect to the distribution network, 25% to the transmission network directly, 5% to the transmission grid via a central injection point and 5% is off-grid. All gasification plants connect to the transmission grid. See Appendix 4 for more details.

**Cost of maintaining the transmission grid:**
All gas transmission companies are obligated under Article 30 of the Commission Regulation (EU) 2017/460[28] to report their costs before the new tariff period. This includes the capital and operational costs that the transmission company expects to make on the grid over the upcoming regulatory period, as well as the allowed revenue. Using public data for five European transmission system operators this study creates an approximation of the cost of the grid today from the allowable revenue for 2023 was divided over the 2023 annual methane demand to get a value in € per MWh demand. This first indication uses the full tariff of the gas transmission network operators for 2023.

Due to the complex nature of determining this tariff in 2040, the factors influencing this tariff in 2040 are qualitatively considered alongside the expected influence on the tariff in 2040.

## 5.3 Modest overall cost of new investments to the grid

Integrating biomethane into the EU gas grid by 2040 requires an estimated € 2.5 billion per year in new investments. This expenditure covers essential upgrades, such as reverse flow stations (€0.6 billion/year) and distribution grid reinforcement (€0.2 billion/year) to handle local demand and production, and enables the transmission of local gases to other regions and gas storages. Additionally, this investment costs estimate covers the full cost of the connection of new biomethane plants to the transmission and distribution networks (€ 1.7 billion/year).

This new investment will not be covered in full by the gas network operators, as these costs are shared with the biomethane plant operators in different ways in different EU countries.[29] For this analysis the whole cost is taken as a simplification.

When considering these investments and their respective operational costs in 2040, the annuitised annual cost of improving the grid to enable 98 bcm of biomethane to access the grid is approximately € 2.0 /MWh when divided across the total volume of methane on the grid with biomethane making up 41% of the grid mix.[30] This is a very low cost for enabling large scale emission reductions.

## 5.4 Comparing gas grid investments with investments in electricity grids

The investments required for the gas grid to 2040 are modest, especially so when considering the investments required to develop the electricity grid. At both distribution and transmission network level, electricity grids need a major revamp to enable the expected increase in electricity use across the EU. Eurelectric have estimated an investment need of € 67 billion/year to 2050 for the distribution electricity grids, [31] while ENTSO-E have estimated an investment need of at least € 33 billion/year to

[28] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas [Link]
[29] Biomethane Industrial Partnership (2024). *Optimising the cost of biomethane grid injection*. [Link]
[30] This considers both distribution and transmission grid cost elements and shouldn't be considered as additional to other costs per MWh in this report.
[31] Eurelectric (2024). *Grids for Speed.* [Link]

2050 for the electricity transmission grids.[32] Together this leads to a new investment of €100 billion/year and € 2,500 billion in total by 2050.
This investment need is approximately 40 times higher than the biomethane-related investments into the gas grid per year, despite the fact the electricity grid enables only 4 – 5 times more clean energy in 2040. This does not consider the additional system value of biomethane as a dispatchable renewable energy carrier compared to the largely variable renewable power enabled by investments in the electricity grids. The gas grid can be seen as a low-cost option for enabling the transport of dispatchable renewable energy.[33]

## 5.5 Most investment costs relate to new grid connections

The total investment required to connect new biomethane plants to the grid in 2040 is € 1.7 billion/year. The exact investment will vary based on the length of the connection, volumes of gas, and national method of cost sharing between biomethane plant operator and gas grid operator.

As anaerobic digestion (AD) plants average size increases, and biomethane increasingly needs to go to the transmission network, an increasing number of AD plants can be expected to connect to the transmission grid. The EU average is assumed to be 25% of AD plants in 2040, up 5% from the situation today.

The cost of the grid connection for 65% of AD plants that are assumed to be connected to the distribution grid in 2040 is included, with consideration for the different requirements of distribution grid connections in terms of connection stations and the lower compression needs. It is important to note that these connections can lead to the need for other new investments such as grid reinforcement and reverse compression.

In addition to AD biomethane plants, all gasification plants are expected to connect to the transmission grid as a result of the larger volumes expected from these plants, with capacities expected to be around 10 - 15 times larger for gasification plants.[34] Given the lack of commercial scale gasification plants on the gas grid today, it is difficult to estimate the connection cost. It is probable that the connection costs will be lower per unit of biomethane than for AD plants as a result of economies of scale in many components such as compressors.

Today, biomass gasification plants producing biomethane are not deployed at commercial level, with all plants at demonstration level. This will be very different in 2040, with 33% of biomethane supply estimated to come from biomass gasification. To get a first estimate of the cost of connection for gasification plants, grid connection costs are conservatively assumed to stay the same with increased volumes of gas, without an assumption on the expected economies of scale.[35]

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[32] € 834 billion by 2050, assumed to have even annual split of investment. ENTSO-E (2024). *Regulatory systems of EU Electricity Transmission System Operators need to be adapted to ensure that the massive grid transmission investment plans can be financed.* [Link]
[33] In 2040, Eurelectric and TYNDP 2024 estimate an electricity demand of 3,400 - 4,000 TWh compared to the 1,035 TWh of biomethane which is enabled by investments into the gas grid. [Eurelectric], [TYNDP 2024]
[34] Navigant (2019). *The optimal role for gas in a net-zero emission energy system.* [Link]
[35] See Appendix 4 for details.

Due to a lack of data, the investment required for central injection points (used to inject biomethane collected from biomethane plants farther afield) are not included in this analysis, however the impact of this investment on the total cost is expected to be minimal as it is responsible for connecting only 5% of the biomethane supply to the grid.

## 5.6 Grid reinforcement as low cost solution to increase grid-injection

Grid reinforcement is as an important part of the upgrades to the distribution gas grid to enable more volumes of biomethane. This investment is modest as it pertains to a connecting piece of distribution pipelines between two local distribution grids, with a total cost estimate of €0.2 billion annually using GIE member data. Grid reinforcement is however limited by the availability of other suitable grids in the area and the fact that in the future the transmission of locally produced gas to other regions and storages will be required.

## 5.7 Reverse compression crucial in the future grid to enable biomethane

A share of the production of distribution-grid-connected biomethane plants will be consumed directly on the distribution grid, but the seasonality of demand and increasing volumes of biomethane mean that not all the biomethane can be consumed locally.[36] To avoid the curtailment of biomethane production in moments when biomethane supply to the distribution grid is higher than the demand, reverse compression stations can be used, allowing transmission to other regions and storages.

In this analysis we use GIE member data to estimate that approximately 3,000 reverse compression stations will be needed across the EU in 2040. Cost estimates for reverse compression stations vary between €1.6 – 4 million depending on size and the need for deodorisation.[37] With an average cost of € 3 million per station the total cost of reverse compression in 2040 is € 0.6 billion per year.[38]

## 5.8 The cost of maintaining the gas grid remain low at reduced methane demand

The gas grid is an extensive, mature infrastructure in Europe. With a focus on the maintenance of the grid and the addition of the modest improvements mentioned above the grid will be available for supplying affordable energy to Europeans across the continent. Despite the narrative that the grid will become expensive to maintain with lower volumes this is not the case. Publicly available data for five of the EU's largest gas transmission network operators[39] shows that today the average tariff today is € 1.50 – 5.10/MWh demand served in the country, with an average of € 3.70/MWh.

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[36] Some biomethane may be injected to the grid at the distribution level and be consumed on the distribution grid, leading to volumes transported on the transmission grid decreasing more than the rate at which total demand decreases. On the other hand, increasing capacities of new production units (including gasification) mean that a larger share of total biomethane production will be directly injected into the transmission grid. These changes are expected to have a modest effect on the expected operation and maintenance cost of transmission grids per unit transported. Given the challenges around determining how much gas is transferred between distribution and transmission grids, no assumption is made on the split of gas between the TSO and DSO grid.

[37] Removing the odorization when bringing methane from a distribution grid (where it is obligatory) to a transmission grid is required in certain EU member states.

[38] See Appendix 4 for full methodology.

[39] This included reports from GRTgaz, Snam, Enagás, Gasunie, and GAZ-SYSTEM

Several aspects will have an influence on how this tariff will change towards 2040. A decrease in methane demand volumes, and any decrease in depreciation period of assets would lead to an increase in the tariff. Conversely, with reduced volumes will come reduced operational costs for compressors and other volume-related costs. Additionally, the current regulated asset base for transmission grid operators will be increasingly depreciated, while some assets will be transferred to the hydrogen regulated asset base. This will all have a cost decreasing effect on the future tariff. With these opposite effects, it can be assumed that the 2040 tariff for maintaining the current transmission grid will stay relatively similar to the tariff today.

# 6. Appendix 1 – Methodology storage analysis

The following section will explain in detail the methodology applied to create profiles for the supply and demand of biomethane in the EU in 2040 to determine the storage volume and withdrawal capacity needs to enable its valuable use.

From looking at demand profiles for the valuable end uses of biomethane and the supply of biomethane it was determined that biomethane supply, and its use in electricity generation and the built environment are the main activities with seasonality, and thus, the main activities requiring biomethane storage.[40]

## Biomethane supply in the EU

For the supply of biomethane in the EU in 2040, the recent report for the European Biogas Association[41] on supply potentials per country was taken. This report gives a production potential for biomethane in the EU of 101 bcm per year (111 bcm in Europe as a whole).

Two main methods of biomethane production are considered, anaerobic digestion and gasification. Today, anaerobic digestion is the only commercial biomethane production method on the market, but this will change in time as gasification is expected to provide 33% of the biomethane in 2040. [41]

A seasonality exists in biomethane production as the decomposition process required for anaerobic digestion is temperature dependent. With decreased ambient temperatures comes a slower rate of decomposition[42] and methane production for the anaerobic share of supply. For this study we assume that 55% of the anaerobic digestion annual production occurs in the middle two quarters of the year around the meteorological summer, and 45% in the first and final quarter of the year around the meteorological winter.[43] Biomethane production through gasification is assumed to be constant throughout the year, as it is not as reliant on wet feedstocks, which are less storable, and is a high temperature process preferably operated at baseload.

Of the biomethane plants today, 9% are known to not be grid connected.[44] We assume this share will be 10% in 2040, but, 5% will be injected to the grid via a central injection point. The other 5% will never make it to the grid, instead being consumed in an end-use where bio-LNG is the demanded energy carrier, assumed in this study to be trucking fuel demand.

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[40] As industrial process heat at low to medium levels begins to be serviced by increasing levels of hybrid solutions e.g. hybrid boilers, a seasonal pattern in industry could emerge, however, this was not included in this analysis.
[41] Guidehouse (2024). *Biogases towards 2040 and beyond*. [Link]
[42] Nie et al., (2021). *How does temperature regulate anaerobic digestion?* [Link]
[43] Similar assumption as taken in recent report by French Energy regulator on the future of gas infrastructure: Commission de regulation de l'energie (2024). *Avenir des infrastructures gazières aux horizons 2030 et 2050, dans un contexte d'atteinte de la neutralité carbone* [Link]
[44] EBA (2024). *From plant to grid: navigating biomethane injection*. [Link]

Considering the total biomethane supply of 1,071 TWh from the European Biogas Association report,[45] this leads to 1,035 TWh of grid connected biomethane in our base scenario, with 2,514 TWh of methane demand coming from the grid, as shown in Table 1., giving a biomethane grid share of 41%.

## Biomethane demand in the EU

To determine the need for storage from demands for biomethane in 2040 this study uses hourly profiles per end use. For the annual demand for biomethane assumed in this study we stick closely to the TYNDP NT+ scenario where possible, with the goal to ground this research in existing literature. This is possible for all end-uses except the built environment: given its seasonal demand and the lack of publicly available hourly data in the TYNDP data. A supplemental analysis is done to create a demand profile for 2040. For all demands the total methane demand is used alongside the proportion of methane that is assumed to biomethane, based on the share of biomethane in the grid mix. In the base scenario analysed in this study, biomethane is 41% of the total methane supply.[46]

### Built environment

Infrastructure is typically dimensioned to handle peak demand moments. For the built environment in the EU this peak is often related to harsh winters. For this reason this study uses a 2010 weather year for the EU, which is a 1-in-20 year annual cold temperature anomaly for the EU. [47]

The built environment here includes the methane demand of residential and tertiary buildings. To begin the analysis, daily gas demand on a EU country level was collected from the ENaGaD database, constructed by the JRC.[48] This database contains daily gas demand for each country between 2015 and 2021 with subdivisions of demand where possible into the categories: industrial users, power generation users, and residential and commercial users. This data largely comes from the transparency platform of National Transmission System Operators.

To analyse the 2040 housing stock such a cold year, we begin with calculating the relationship between residential and commercial gas demand and temperature for existing data. ENaGaD residential and commercial gas consumption data for EU countries data for 2018 is taken where available, as 2018 was the year with the EU peak gas demand in the available time series. Countries with this data available represent 85% of the total EU gas demand in 2018.
For the remaining countries which do not have a split between residential and commercial consumption, Eurostat annual data on natural gas use in households and for commercial and public services sectors was taken and converted to hourly demand by assuming the same demand profile. fitting this data to the profile of neighbouring countries expected to have similar heating profiles.

A relationship between temperature and gas demand per country can then be determined. To do this the average daily temperature for the EU countries for 2018 and 2010 was taken from the National Oceanic and Atmospheric Administration (NOAA) climate database.[49] This was done for the capital city of each country where possible, except for Italy, where due to the large climatic differences in the

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[45] Guidehouse (2024). *Biogases towards 2040 and beyond*. [Link]
[46] 1,035 TWh of biomethane supply and 2,514 TWh of methane demand.
[47] EEA (2024). *Global and European Temperatures.* [Link]
[48] European Commission Joint Research Centre (2022). *The European Natural Gas Demand database (ENaGaD).* [Link]
[49] National Oceanic and Atmospheric Administration (NOAA). [Link]

country and the concentration of gas heating needs in the north of the country, a weather station near Milan was chosen instead.

Using the daily gas demand for the residential and commercial sector in 2018 and the average daily temperature, a regression analysis was done to determine the relationship between temperature and gas demand for a 2018 building stock in each EU country, shown in Figure 8. This resulted in an equation for this relationship of gas demand and temperature for each country.

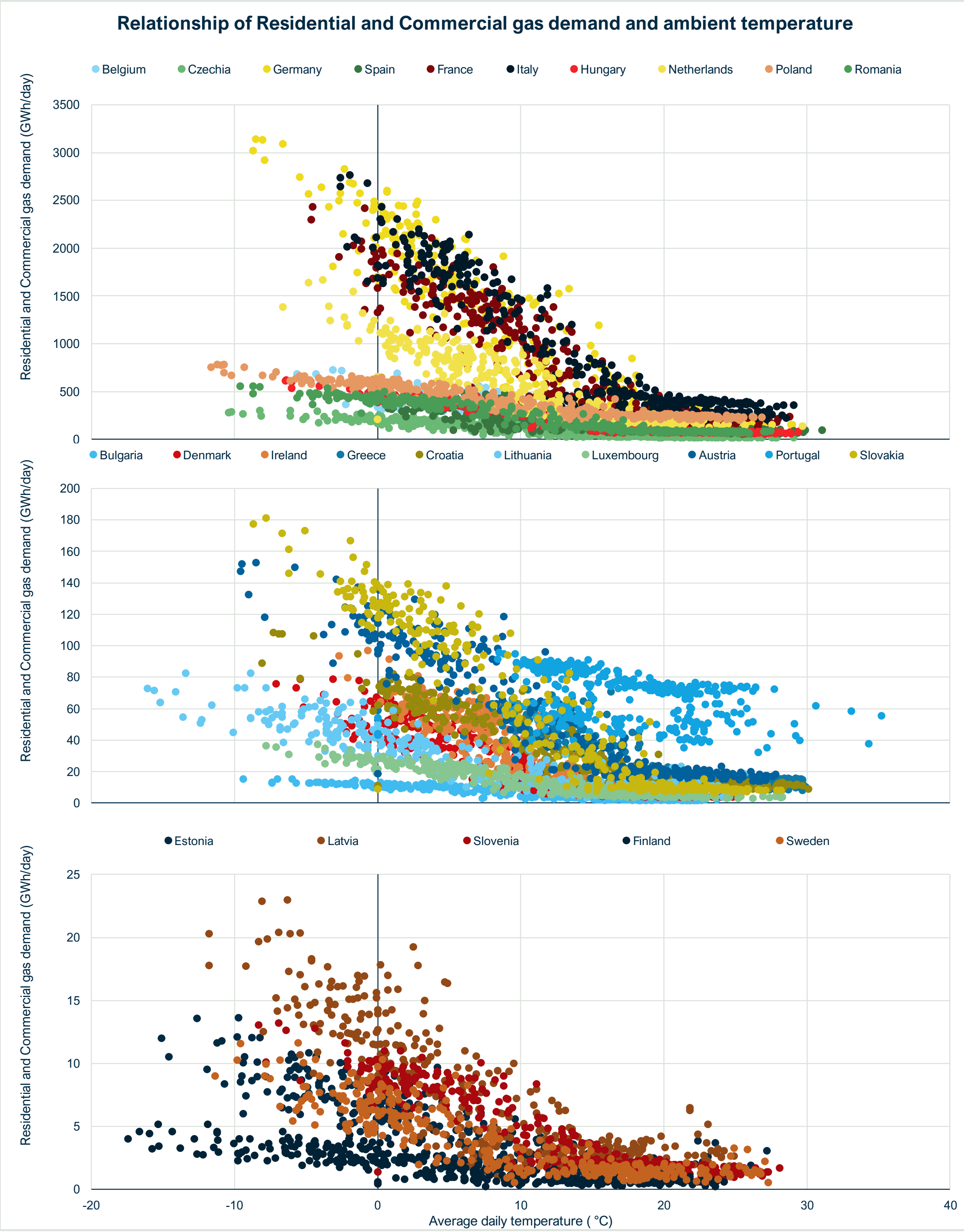


*Figure 11. Temperature-gas demand relationship for EU countries based on 2018 data.*

By inserting 2010 temperature data into the formula the gas demand of a 2018 building stock for a 1-in-20 weather year is calculated, indicating that the gas demand in the residential and commercial sector would have been 18% higher in 2018 has the temperature been at 2010 levels.

To convert this building stock to a 2040 building stock, several steps were taken.

**Step 1: Building renovations**

The building stock underlying the gas demand is from 2018. To correct this to 2040, a renovation rate must be assumed. Despite efforts to increase the renovation rate of Europe's building stock, the average European renovation rate has been 1% from 2011[50] up to 2023. [51] As such, this report assumes the renovation rate to remain at 1%. However, the share of deep renovations has increased, and currently accounts for 20% of the renovations,[52] with the remaining 80% of the renovations being minor to moderate. The Buildings Performance Institute Europe estimates a deep renovation to save approximately 75%, and minor to moderate renovations to save 15-45%. Applying these assumptions to the building stock for the 22 years from 2018 to 2040, results in 9% annual energy savings due to energy renovations by 2040. [53]

**Step 2: Some buildings will stop using gas**

By 2040, it is assumed that the heating system replacement rate today of 4% will remain constant, leading to a ~90% replacement of heating technologies.[54] Of this , it is assumed that 25% will transition away from gas due to a combination of factors including stricter environmental regulations, advancements in renewable energy technologies, and growing consumer awareness of the need to reduce carbon emissions. Governments are increasingly promoting policies that favour energy alternatives in the home like all-electric heat pumps and district heating, and consumers are becoming more conscious of their carbon footprint. Additionally, the rising costs of fossil fuels and incentives for adopting greener technologies are expected to drive this shift.

**Step 3: Buildings that continue to use gas boilers**

The above assumption on replacement rate of heating technologies leaves 25% of buildings in the EU with a gas connection that are not assumed to replace their gas boiler. These buildings are assumed to continue using gas boilers due. Part of the reason for retaining the gas boiler can be the high upfront costs of switching to alternative heating systems, such as heat pumps, and the need for deep retrofitting of buildings for new energy technologies which can be complex and costly.

**Step 4: Buildings that switch to hybrid heat pumps**

Of the gas grid-connected buildings in 2018, two-thirds (50% of the total building stock) are expected to transition to a hybrid heat pump by 2040. Hybrid systems, which combine gas boilers with electric heat pumps, offer flexibility and efficiency, allowing buildings to transition to renewable energy while still relying on gas during peak demand or colder periods. These systems are more cost-effective than full electrification, with lower upfront costs for large electric heat pumps and the associated renovations to the building envelope required, making them an attractive option for the consumer. Additionally, the shorter timeline to 2040 means that hybrid solutions are seen as a practical middle ground, balancing the need for sustainability with the challenges of retrofitting older buildings. On the energy system side,

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[50] BPIE (2011), *Europe's buildings under the microscope*. [Link]

[51] BPIE (2023). *How to stay warm and save energy*. [Link]

[52] European Commission (2019). *Comprehensive study of building energy renovation activities and the uptake of nearly-zero buildings in the EU.* [Link]

[53] This methodology is a simplification as the temperature-gas demand relationship is also influenced by renovations to the building stock. This assumption should be improved in any future study.

[54] Replacement rate of heating systems of 4% between 2018 and 2040. European Commission (2014). *Communication on codesign requirements for space heaters and combination heaters* [Link]

they make use of the high capacity of gas infrastructure, avoiding the need for costly electricity grid expansion with a very low capacity factor.

**Step 5. Assumption on gas demands not related to space heating**

For the remaining gas connected buildings in 2040, 100% of domestic hot water is assumed to be supplied by methane, as commonly happens in boiler and hybrid heat pump connected building stock. Gas use for cooking is expected to reduce at a rate similar to the renovation rate. Following observations that the move away from gas cooking happens quicker than gas heating we assume that for boiler using homes cooking switches away from gas at the renovation rate, while for hybrid heat pump connected homes the switch happens at 1.5 times the renovation rate of the building stock.

**Step 6. Operation modes for hybrid heat pumps**

For the hybrid heat pump connected homes, the set up and operation of the hybrid heat pump will have a significant impact on the gas demand of the home. Typically today hybrid heat pumps have three operation modes based on the ambient temperature and thus the COP of the heat pump component.

- ***Operation mode A:*** When the ambient temperature is not too low, the heating load can be comfortably met with the heat pump and thus no gas is used for space heating. This is assumed to be at ambient temperatures of above 3°C in the EU.
- ***Operation mode B:*** When the ambient temperature drops to a level that the COP reaches a pre-set limit, the gas boiler begins to assist the heat pump in meeting the heat load for space heating. This is assumed to be at ambient temperatures between -3°C and 3°C. In this mode it is assumed that 30% of the heat load for space heating comes from gas.
- ***Operation mode C:*** When the ambient temperature drops to a level where the electric heat pump component will have a low COP and/or operating problems, the gas boiler is used to supply the full heat load for space heating. This is assumed to occur at temperatures below -3°C.

This analysis gives the daily demand analysis. To get to hourly data (important for electricity generation), the heating profile is assumed to be constant over the day. This should not have a large influence on the result given the relative spread of heating profiles between different building types in the EU. [55]

## Electricity generation

To estimate the need for storage to enable the use of biomethane in electricity generation in the EU in 2040, we use data from existing energy system model studies, namely the TYNDP 2024. These are the joint scenarios of the EU electricity and gas transmission network operators developed for the Ten-Year Network Development Plan. The TYNDP uses three scenarios, National Trends+ (NT+), Global Ambition (GA), and Distributed Energy (DE). These scenarios are as follows.

**National Trends +:** In this scenario, countries focus on national priorities and policies, leading to a more gradual transition with moderate investments in renewable energy. It reflects diverse national strategies, with energy systems adapting based on local resources and political considerations, resulting in more gradual, less coordinated decarbonization efforts.

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[55] Alliander data taken from Voulis et al., (2019). *Rethinking European energy taxation to incentivise consumer demand response participation.* [Link]

**Global Ambition:** This scenario envisions a fast and globally coordinated transition, driven by strong international collaboration and significant investment in large-scale renewable projects, such as offshore wind and hydrogen. It focuses on a centralised approach, leveraging technology and global supply chains to accelerate decarbonisation by 2050.

**Distributed Energy:** This scenario emphasises a decentralised energy future, where local energy production, energy efficiency, and consumer participation play key roles. It envisions widespread adoption of distributed renewable sources, such as rooftop solar, and active consumer involvement in energy management.

Methane has been shown to have an important system role for balancing the electricity system in previous versions of the TYNDP, however this edition has shown a notably diminished role for methane in the power system. In the 2022 version of the TYNDP, these scenarios showed methane providing 15%, 7%, and 10% of the electricity mix respectively. In the TYNDP 2024 results this was reduced to 5%, 0.4% and 1% respectively, see Box 1. For explanation.

*Box 1. Learnings on large differences in gas-fired electricity generation in TYNDP scenarios.*

The TYNDP 2024 scenarios show significant variations in gas-fired electricity generation by 2040, particularly between the **National Trends** (NT+) and the **Distributed Energy** (DE) and **Global Ambition** (GA) scenarios. Although the installed capacities for gas-fired power plants, including both methane and hydrogen units, remain nearly constant across all scenarios, the role and utilisation of gas-fired generation differ greatly.

In the National Trends scenario, gas-fired power generation decreases by 37% from 2030 to 2040, resulting in 268 TWh of generation in 2040. Of this 268 TWh of power produced, 60 TWh comes from ‘must-run’ CHPs, the rest coming from gas powered units that respond to market price mechanisms.
The DE and GA scenarios predict a much steeper decline, with gas-fired electricity generation falling to between 21 TWh and 61 TWh by 2040, accounting for only 0.4% to 1% of total electricity production.

There are several drivers for this difference:

- **Increased short-term flexibility:** Both DE and GA scenarios assume significantly higher levels of short-term flexibility, such as through batteries, vehicle-to-grid (V2G) systems, and demand-side response (DSR). This flexibility reduces reliance on gas-fired power plants to balance the grid, as these resources provide backup during periods of low renewable output. However, there are concerns that the assumptions regarding V2G and DSR availability may be overly optimistic, as they assume near-continuous availability of these resources.
- **Higher renewable energy capacity**: The DE and GA scenarios see much greater expansion of renewable generation compared to NT+. These scenarios assume that renewables not only meet rising electricity demand but also supply a significant share of hydrogen production via electrolysis. As a result, gas-fired plants are dispatched less frequently, primarily serving as a backup for extreme conditions when renewable output is insufficient.

- **No must-run obligations:** Unlike the NT+ scenario, the DE and GA scenarios do not impose "must-run" obligations on gas-fired plants, meaning these units are only dispatched when absolutely necessary. In NT+, gas plants might still be used for reasons beyond electricity production, such as system stability or district heating, which is not accounted for in DE and GA.
- **No additional revenue streams for gas units:** DE and GA do not consider potential additional revenue streams for gas-fired power plants, such as providing system stability services or producing heat for district heating. This further reduces the utilisation of gas plants in these scenarios.

**Full-load hours**

As a result of what is described above, the full load hours (FLH) of gas-fired plants in NT+ are much higher, reaching 1,689 hours in 2040, while in DE and GA they drop dramatically to 287 and 87 hours, respectively. This reflects the reduced reliance on gas-fired power generation as renewables and flexibility measures take on a larger role in the energy mix.

**Modelling differences and concerns**

NT+ uses a simpler model compared to DE and GA, which include more complex components such as a prosumer node, EV node, and synthetic fuel production. This added complexity in DE and GA allows for greater flexibility on the electricity side, but there are concerns that the model likely overestimates the availability of flexibility, particularly from V2G and DSR.

Moreover, insights from an interview suggest that the flexibility from imports might also be overestimated. Both models account only for cross-border grid constraints but do not take into account limitations within the national grid infrastructure, meaning that transmission bottlenecks within countries are not fully considered. This results in an overly optimistic view of the available flexibility from imported electricity, also in the NT+ scenario.

The NT+ results are taken as the most realistic of the three scenarios, as the DE and GA scenario overestimate flexibility in the electricity system (Box 1), resulting in an extremely low use of gas-fired power. The electricity generation mix for the NT+ scenario per node per hour[56] and the average efficiency of methane-powered electricity generation in the TYNDP report[57] are used to produce an hourly methane demand curve for each EU country. This can be used together to create a hourly methane demand curve for the EU for electricity generation in 2040.

The methane demand for district heating is included under the power generation header in the TYNDP, and as a simplification this methane demand is assumed to follow the power generation profile provided. This simplification is made as a result of a lack of detail on the district heating profile from methane in the report.

[56] TYNDP (2024). Scenario outputs. NT+ 2040 Modelling Results – Climate Year 2009.

[57] An average efficiency of gas-fired power generation in the report of 41%

## Demand volumes and profiles from other sectors in 2040

For the remaining biomethane demands, the total volumes from the TYNDP NT+ scenario are taken and converted to hourly demands assuming a baseload profile. The included demands are the valuable end-uses highlighted in this study, industry, shipping, and trucking fuels, and additionally the other methane demands included in the TYNDP, SMRs, non-energy use, agriculture, and other. These demands are assumed to be baseload following investigation in the typical profiles for these industries today.

## Using supply and demand profiles to get insights into the need for storage in 2040

With profiles of biomethane supply and the biomethane share of demand the storage implications can be found. This analysis considers demand to match supply, and as such no oversupply or shortage is found in the year and there is no influence on storage needs of back to back weather years. The storage withdrawal capacity needed for biomethane is determined by finding the maximum hourly difference between supply and demand. The total volume of storage needed for biomethane is determined by the cumulative over and undersupply of biomethane in the year.

# 7. Appendix 2 – Methodology for pipeline analysis

This section provides a detailed description of the methodology used to gain insights into pipeline needs for the use of biomethane in valuable end uses by 2040. This was done by an analysis of supply and demand potentials in four archetype regions. For each archetype, we estimated both the annual supply and demand volumes, as well as demand and supply profiles throughout the year. Based on these estimations, we gained insights into several key aspects of infrastructure requirements:

- **Sourcing Area:** The annual demand and supply potentials in the archetypes highlight the potential size of disparity between regional supply and demand. This provides an indication of the extensiveness of the pipeline network required to address the mismatch, by supply from or to other regions and/or storages.
- **Pipeline Capacity:** The demand and supply profiles in the archetypes provide insight into the potential peak demand or supply. The peak difference between demand and supply helps assess the capacity of pipelines needed to handle peak periods.

The section first describes the archetypes in more detail, as well as the selection criteria for the real-world examples. This is followed by the methodology used to determine the supply potentials and profiles for the archetypes. The third sub-section describes the approach used to determine the potential biomethane demand (profiles) for each of the key use sectors: built environment, industry, electricity, shipping, and trucking.

## Archetype selection

The archetypes used for this analysis are inspired by real-world locations and aim to represent a wide range of regional characteristics across Europe. We selected archetypes that reflect the diversity of the continent in terms of methane demand, biomethane supply potential, and geographical location. Each archetype is a circular area with a radius of 50 km, providing a manageable and comparable scope for assessing infrastructure needs.

To ensure the analysis captures the varied situations across Europe, the archetypes were chosen from different climatic regions and geographical corners. This allows the analysis to consider the potential effects of climate on methane demand, particularly in heating and electricity generation. We also accounted for regions with distinct compositions of methane demand, such as those driven by industrial needs, electricity generation, or residential heating, as well as a net supply region with surplus biomethane production.

Based on the criteria describe above, the following archetypes were developed:

- **Archetype 1: High Demand and Supply region.** This archetype has high biomethane demand driven by space heating, electricity generation, industry, and a large port with LNG bunkering. It also has significant supply potential from agricultural and urban waste sources.

- **Archetype 2: Industrial Gas Demand region.** This region is characterised by a high industrial gas demand, moderate electricity generation, little residential gas use, and a medium-sized port with LNG bunkering.
- **Archetype 3: Electricity Production-Focused region.** This region has significant gas-fired electricity production and industrial methane use, particularly used for emission reduction in primary steelmaking. Residential gas demand is present but not dominant. This region is inland so no bunkering occurs here.
- **Archetype 4: Net Supply region.** A rural area with significant agricultural land, providing strong biomethane production potential. Demand across all sectors is low, mainly from the built environment, positioning the region as a net supplier to others.

By selecting these archetypes, we aimed to model typical locations that can be applicable to other parts of Europe, even if not directly represented in the study. For example, the second archetype could represent any other region with a similar mix of electricity demand and large baseload industries, while the fourth archetype might capture the dynamics of a rural, net-supply area. In this way, the analysis provides insights that can be generalised to other regions with similar profiles, offering a broader understanding of Europe's biomethane infrastructure needs.

## Biomethane supply in Archetypes

To estimate the regional biomethane supply potentials of the archetypes, we used information on current land use in the country and regions, and estimates for national production potentials in 2040.[58] The estimate was calculated in two main steps:

1. **Calculation of supply density per type of land (bcm/km$^2$) based on national data.** We first determined the national supply potential for 2040 for each production technology. The supply density for AD (anaerobic digestion) was calculated by dividing the national AD potential by the total agricultural area,[59] while the supply density for gasification was calculated by dividing the national gasification potential by the total urban[60] and forestry areas[61].[62]
2. **Calculation of regional supply potential by multiplying the supply density per land type with the respective area of land in the region**. For each archetype region, we applied the relevant national supply densities to the specific land use areas within the region. For example, in Archetype 1, the national AD potential is 1.9 bcm, and the total national agricultural area is 18,000 km², resulting in an average supply density of 0.000105 bcm/km² of agricultural area. The region's agricultural area (3,500 km²) was multiplied by this density to estimate a biomethane supply of 0.4 bcm/a in 2040. Similarly, the gasification potential in the region was estimated using the urban area and its respective supply density.

In the main analysis, we used the 101 bcm scenario for EU-wide supply potential. In a sensitivity analysis, we also considered a lower production potential scenario with supply from the TYNDP NT+ scenario. The reduction was split approximately evenly between AD (via sequential cropping) and gasification,

[58] Taken from the recent Guidehouse (2024) study commissioned by EBA: Biogases towards 2040 and beyond, figures 2 and 3. This study estimates the EU supply potential in 2040 to be 101 bcm/a.
[59] Eurostat (2024). Utilised agricultural area by categories.
[60] Eurostat (2019). Land cover and land use.
[61] Eurostat (2023). Forests, forestry and logging.
[62] Corine land use maps per region used to determine the urban, agriculture and forestry area in the region

resulting in 45% less potential from sequential cropping and 55% less from gasification. These reductions were applied to the relevant supply potentials in the archetype region to estimate the lower production scenario.

All supply in the archetype regions was assumed to make it to the grid as a result of the existing pipelines infrastructure that is in the chosen regions.

## Biomethane demand in Archetypes

To analyse biomethane demand in the archetypes, the analysis looked into five gas demand sectors for each archetype region: the built environment, electricity generation, industry, shipping and trucking. For each sector, we estimated demand volumes and profiles based on various data sources, calculations and assumptions explained in more detail for each sector below.

- **Demand profiles** were assumed to be roughly baseload for industry, shipping and trucking – and developed by evenly spreading out the annual demand volume over the 8760 hours in the year. Electricity and built-environment profiles were constructed from TYNDP profiles and temperature data to show more varying profiles; these were analysed in more detail.
- Sectoral biomethane annual **demand volumes** were determined by estimating the total methane demand and multiplying this by the calculated share of biomethane in the total methane supply by 2040, as explained in Chapter 2 section 2.2.

### Gas demand in the built environment in Archetypes

Based on the EU-level built environment gas demand calculation, an estimate for the gas demand in the built environment can be made for the archetype regions. Because the dominant gas demand in the built environment is related to space heating and thus to the number of people we assume there is a relationship between this gas demand and population. For each country, we take the current percentage of the national population that lives within the archetype region. Then the same percentage of the national 2040 gas demand estimate is assumed to be found in the archetype region, with the same profile as the national calculation.

### Electricity gas demand in Archetypes

The TYNDP data output for the electricity generation mix on an hourly basis in the NT+ scenario per country is taken for 2040.[63] Using available public data, the capacity of gas fired power plants within the archetype region as a share of the national capacity are determined for today. This concentration of gas-fired power plants is assumed to stay the same through time to 2040, and the existing power plants are assumed to remain online. Using TYNDP national data for gas-fired power generation in 2040 and the share of national gas fired power plants in the archetype region today, the 2040 profiles for electricity production in the region - based on 2009 weather year - were estimated.

### Industrial gas demand in Archetypes

The TYNDP data output for the industrial demand for methane in the EU in the NT+ scenario was used to estimate the change in industrial methane demand from current levels towards 2040 projections. This projection shows a reduction of 42%. Using available public data, current methane demand for industry in the archetype region is approximated. The decrease in methane demand for industry is assumed to

[63] TYNDP (2024). Scenario outputs. NT+ 2040 Modelling Results – Climate Year 2009.

occur evenly across the EU and thus the ratio of industrial demand for methane in the NT+ scenario for 2040 compared to today is used to determine the reduction in the methane demand of industry in the archetype region. Where suitable, the use of biomethane as a novel emission reduction strategy is considered. This is most notable in Archetype 3 where a primary steel plant that today runs on coking coal is assumed to switch to methane-based direct reduction of iron (DRI). This allows for full decarbonisation with the use of biomethane or other renewable forms of methane. The industrial methane demand for Archetype 3 thus includes this DRI plant and the current methane using industry following the reduction assumed in the TYNDP NT+ scenario for 2040.

### Shipping gas demand in Archetypes

To determine the international shipping methane demand in the archetype regions in 2040, the situation today was extrapolated to 2040, using insights from TYNDP. EU bunkering data for 2022 gives an indication of the total volumes of maritime bunkering in the EU today.[64] Using publicly available data on the bunkering locations within our archetype regions and the national bunkering volumes we determined the share of EU bunkering done within our archetype regions.

Taking the NT+ scenario of the TYNDP, there is a demand for methane in international shipping of 75 TWh in the EU in 2040. It is assumed that the relative share of bunkering done per port in the EU stays constant through time to 2040. The 2040 volume of methane demand for shipping in the archetype regions can thus be calculated using their 2022 share in the total EU bunkering demand multiplied by the 75 TWh demand for international shipping in the EU in 2040.

### Trucking gas demand in Archetypes

The estimation of methane demand for trucking in 2040 in the archetype region is based on real-life examples using the following steps:

1. **Starting Point - 2022 Energy Demand:** The baseline is the 2022 energy demand for road transport in the country of the archetype, as reported in Eurostat data.[65]
2. **Current CNG/LNG Infrastructure:** The current number of CNG/LNG stations in both the archetype region and the country as a whole was sourced from Habo LNG data.[66] The share of the archetype region's CNG/LNG stations in the national total was calculated as a basis for regional demand estimation.
3. **Future Energy Demand Projections:** The TYNDP NT+ scenario at the EU level was used to project changes towards 2040. This included a projected 41% decrease in total energy demand for road transport from 2022 levels and an 8% share of methane in the total energy supply for road transport in 2040, assuming all methane demand will be in heavy-duty transport.
4. Estimation Steps:
   - **National Energy Demand in 2040:** The 2022 national energy demand for road transport was adjusted by the projected 41% decrease in TYNDP (2024) to estimate the 2040 demand.
   - **National Methane Demand in 2040:** This 2040 estimate was then multiplied by the projected 8% share of methane in road transport in TYNDP (2024) to estimate the national methane demand for 2040.

[64] Eurostat – Fuel oil and motor petrol and diesel and blended gas diesels
[65] Eurostat (2024). Final energy consumption in road transport by type of fuel.
[66] European CNG and LNG gas stations | Alternatívne palivá LNG, CNG, BioLNG, BioCNG (habolng.sk)

- **Regional Methane Demand in 2040:** The national methane demand estimate was further adjusted by the current share of the archetype region in national CNG/LNG stations to estimate the methane demand in road transport in the archetype region.
- **Regional biomethane Demand in 2040:** The estimated 2040 methane demand for the archetype region was multiplied by the projected share of biomethane in methane supply[67] to estimate the biomethane demand for road transport in the archetype region.
- **Remove demand directly supplied by off-grid produced bio-LNG:** Some of the demand is expected to be served by off-grid produced biomethane supplied directly as bio-LNG. The share of demand supplied in this way is assumed to be the EU share of off-grid biomethane supply relative to trucking fuel demand, which is 25% in the base case, and 19% in the TYNDP NT+ supply scenario case.

[67] The share of biomethane in methane supply in 2040 was determined by dividing the supply of biomethane in the scenarios (101 bcm and 72 bcm) by the total methane demand in 2040 in the NT+ scenario of TYNDP 2024.

# 8. Appendix 3 - Normal winter year for the built environment

Infrastructure needs to be sized to be able to supply sufficient energy at times of peak demand and supply; this is why it makes sense to use a relatively cold year for the base case infrastructure analysis. This also complies with EU Regulation on securing energy supply. However, it is also interesting to investigate how demand looks in a 'normal' weather year. This does not influence the needed capacities, but instead indicates what 'usual' operating conditions would look like by 2040. When analysing a normal weather year, there is a notable reduction in the volume of methane taken from storage, but importantly, this analysis shows that even in so called normal weather years, specific weather events can lead to large withdrawal capacity needs from underground gas storages.

When analysing gas infrastructure implications of gas use in the built environment, the base case analysis assumes a 1-in-20 cold weather year in the EU. This is characterised by using 2010 temperature data, see Figure 12. Infrastructure has to be available at capacities that are capable of handling the peak moments of demand, which often come with stress moments for the energy system and stress moments for society, e.g. prolonged severe cold events.

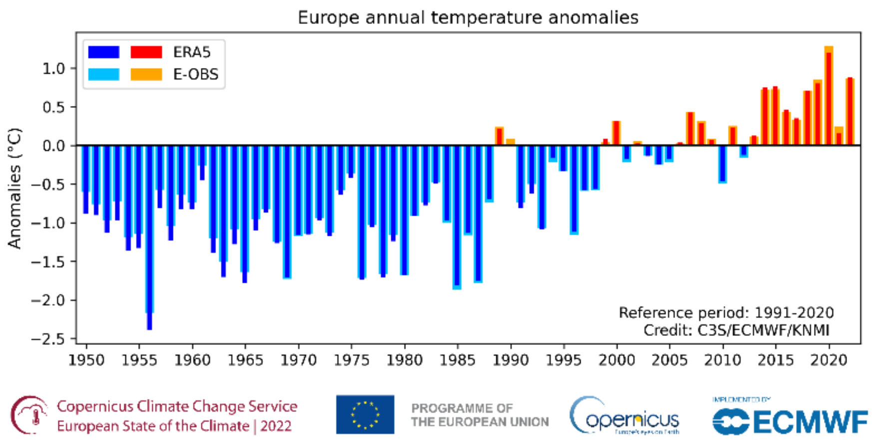


*Figure 12. Annual temperature anomalies on an EU level. Source: Copernicus Climate*

While this 1-in-20 weather year cold event is important for sizing infrastructure, it is also useful to investigate what demand is in the built environment under 'normal' conditions, and to what extent gas infrastructure is needed. With a general warming of the climate expected, taking a weather year between 2015 and 2020 can likely represent a more commonly experienced weather year in 2040. To analyse this 2013 temperature data is taken to represent a more 'normal' weather year.

Under these normal conditions for the built environment analysis, total gas demand changes significantly, decreasing 15% from 822 TWh to 696 TWh. This decrease sees the total methane demand of our study reach levels similar to the TYNDP NT+ scenario, with a 97 TWh demand difference, likely a result of the difference in heating technology mix assumptions.

As is to be expected, the demand profile for gas consumption in the built environment changes notably when different weather years compared to a 1-in-20 years cold weather year, as seen in Figure 13.

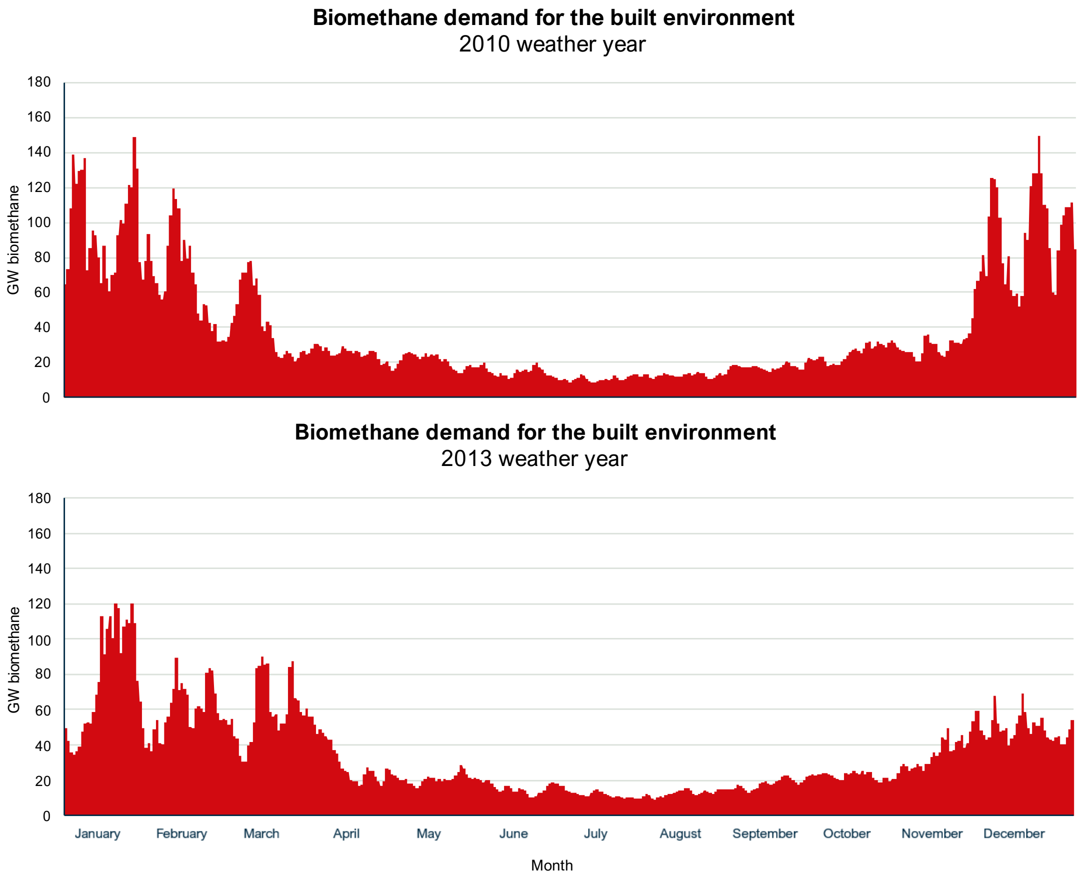


*Figure 13. Annual demand profiles for biomethane in the built environment on an EU level in a 1-in-20 years cold weather year - 2010 (top), and a normal weather year, 2013 (bottom).*

### *Changes in storage needs*

The impact of a normal weather year is notable, as reduced total demand allows biomethane become 43% of the gas on the grid. The infrastructure needs are impacted by this change to total volumes, with a reduction to the storage volume needed decreasing to 154 TWh of biomethane, 30% lower than the storage volume needs for biomethane in a 1-in-20 year weather event, see Table 7.

*Table 7. Overview of main characteristics on biomethane storage needs in the base scenario based on a 1-in-20 years cold weather year and a scenario with a 'normal' weather year.*

| Main characteristics analysed | | | '1-in-20' weather year | 'Normal' weather year |
|---|---|---|---|---|
| Biomethane | Storage volume need | *TWh* | 183 | 154 |
| | Peak withdrawal needs | *GW* | 184 | 128 |

### *Changes in pipeline needs*

The pipeline needs analysis reflects the same trend. As a result of increased biomethane share in the total methane supply, and a reduced use of methane in the built environment, there is an decreased demand for biomethane in regions with significant gas use in the built environment (High Supply and Demand region) and increased demand in archetypes where the majority of gas use is in other sectors

(Industrial Gas Demand and Electricity Production-Focused region), as shown in Table 8. The net supply region sees a negligible increase in local demand and remains a net supply region.

The decrease in seasonal demand from the built environment leads to a 0.6 GW decrease in pipeline capacity for biomethane in the High Supply and Demand region and the increase in biomethane share of the grid leads to a slight increase in the peak capacity of pipelines needed for biomethane in other regions.

*Table 8. Overview of main characteristics on biomethane pipeline needs in archetypes in the base scenario based on a 1-in-20 years cold weather year and a scenario with a 'normal' weather year.*

| | | **Archetypes** | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **High supply and demand** | | **Industrial gas demand** | | **Electricity Production-Focused** | | **Net supply region** | |
| **Main characteristics analysed** | | **1-in-20 weather year** | **Normal weather year** | **1-in-20 weather year** | **Normal weather year** | **1-in-20 weather year** | **Normal weather year** | **1-in-20 weather year** | **Normal weather year** |
| Annual biomethane supply | *TWh* | 6.2 | 6.2 | 2.1 | 2.1 | 2.3 | 2.3 | 2.0 | 2.0 |
| Annual biomethane demand | *TWh* | 30.0 | 29.7 | 10.0 | 10.5 | 19.7 | 20.3 | 0.5 | 0.5 |
| Biomethane demand vs. supply | - | 4.8 | 4.8 | 4.8 | 5.1 | 8.4 | 8.7 | 0.3 | 0.2 |
| Peak capacity for biomethane import/export | *GW* | 8.9 | 8.3 | 2.9 | 3.0 | 3.7 | 3.7 | 0.2 | 0.2 |

# 9. Appendix 4 – Cost analysis methodology

## New investments calculations

### Connection costs

In the EU, on average ~20% of biomethane plants were connected directly to the transmission grid in 2022.[68] This is estimated to rise to 25% of anaerobic digestion plants in 2040 as a result of increasing average plant capacity[69] and a reduced demand on some distribution grids in 2040. Additionally, all gasification plants can be assumed to connect to the transmission grid.

The cost of connecting these plants to the transmission grid varies based on several factors, such as the length of the connection and volumes of gas, with an average cost of € 2.3 million per AD plant reported by GIE members. This costs estimate includes the pipeline, injection, compression, and other elements such as gas quality control.

For gasification plants, due to a lack of data on the economies of scale, the cost of connection to the transmission network per unit of energy are assumed to stay the same as the cost of connection for anaerobic digestion plants. Gasification plants are typically 10 - 15 times larger than the average anaerobic digestion plant (12 assumed for the calculation).

The EU average situation today, with a majority of anaerobic digestion plants connecting to the distribution network is expected to remain the same in 2040. This percentage is assumed to reduce slightly to 65% in this study. [69] This percentage will change notably between countries depending on the grid topology and location of new biomethane plants.

GIE member insights indicate the cost of connecting biomethane plants to the distribution grid is approximately € 0.6 million per plant. This costs estimate includes the pipeline, injection, compression, and other elements such as gas quality control.

Using the average plant size of 650 $m^3/h$ an indication of the number of connections required by 2040, and the investment it requires were calculated. In total these new investments reach € 1.7 billion/year for the EU on average between today and 2040.

Operational costs are estimated to be 4% of the investment costs per year for transmission grid connections, and 8% of distribution grid connections based on GIE member input.

### Grid reinforcement costs

To determine the need for distribution grid reinforcement we consulted input from GIE members. Two key pieces of input indicated that the total investment needed in grid reinforcement should be around

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[68] 70% connected to the distribution grid, 20% to the transmission grid and 10% off grid: EBA (2024). *From plant to grid: navigating biomethane injection*. [Link] – with extrapolation for unknown data. As the grid connection of biomethane plants is determined via an economic optimisation between the gas distribution and transmission, the exact percentage split will change per country and grid topology.

[69] Average plant size assumed to rise from ~450 $m^3/h$ in 2023 to ~650 $m^3/h$

20 – 25% of the investment required in reverse compression stations, and that this would require on average a € 0.3 million investment into the distribution grid per connected plant.

The total investment required for this grid reinforcement is then divided evenly across the 16 years between today and 2040 to get the investment per year for grid reinforcement of € 0.2 billion/year.

Operational costs are assumed to be 3% of the investment costs annually based on GIE member input.

**Reverse compression costs**

To determine the need for reverse compression stations we consulted the GIE members. From submitted data we found that studies indicate a reverse compression station will be need for every 2 - 4 distribution grid connected biomethane plants in the future. The average is taken as a reverse compression station for every 3 distribution grid connected biomethane plants.

GIE member data indicates reverse compression stations are approximately € 1.6 – 4 million depending on size and the need for deodorisation. For this study we assume an average cost of € 3 million per station.

Considering the average biomethane plant size and the estimated amount of distribution grid connected plants, it is estimated that ~3,000 reverse compression stations will be needed across the EU in 2040. The total investment required for these reverse compression stations is then divided evenly across the 16 years between today and 2040 to get the investment per year for reverse compression stations of € 0.6 billion/year

Operational costs are assumed to be 3% of the investment costs annually based on GIE member input.

**Annual cost of new gas grid investments in 2040**

The annual cost of the total required investments in the year 2040 can be calculated with the above data, considering the required investments, an annuity factor, and the operational costs in 2040. To convert the average required investments of € 2.5 billion/year to a capital cost a discount rate of 6% is assumed, as is typical of a regulated business, alongside a conservative lifetime of the investments of 20 years for all investments except for the grid reinforcement which has a lifetime of 50 years. Altogether, the capital cost in 2040 amount to € 3.4 billion/year. This annual capital cost for 2040 can be considered alongside the necessary operational costs of € 1.7 billion/year to give an indication of the total cost of enabling 98 bcm of biomethane into the grid in 2040, as shown in Table 9.

*Table 9. Summary of the average annual investments required in the gas grids up to 2040, the annuitized annual capital costs, and operational costs for the year 2040.*

| | Grid reinforcement (€ mln) | Reverse Flow (€ mln) | Connection costs (€ mln) | Total (€ mln) |
|---|---|---|---|---|
| **CAPEX (required investments)** | ~200 | 600 | 1,700 | 2,500 |
| **Annual capital cost of investments in 2040** | ~200 | 850 | 2,400 | 3,400 |
| **Annual OPEX in 2040** | ~100 | 300 | 1,300 | 1,700 |
| **Total annual cost** | 250 | 1,150 | 3,700 | 5,100 |

This total annual cost € 5.1 billion/year can be divided across the total volume of gas of the grid in 2040 in this study (2,514 TWh), to determine the cost of enabling biomethane per MWh of total gas use. This is a cost of € 2.0 /MWh.

It is important to note that this is a first level approximation for both the distribution and transmission grids and not intended to be an indication of the development of the gas transmission tariff. The annuity method of calculation here is not how regulated assets are discounted, instead this calculation gives an indication of the order of magnitude of the cost of biomethane integration into the gas grid in 2040 in € per MWh of gas on the grid.

## Cost of operating and maintaining the transmission network

Public data was collected for several of the large European gas transmission network operators, namely GRTgaz, Gasunie, Gaz System, Enagás, and Snam from the regulatory period concerning 2023. From these public reports allowed revenues for 2023 was taken as an indication of the cost required to operate and maintain the current gas grid. While allowed revenues also includes depreciation and other components not directly related to operation and maintenance, used allowed revenues for the costs gives a complete picture of the cost of maintaining a normally operating gas grid.

The allowed revenues for each transmission network operator range from € 490 million to € 2,410 million, which is to be expected given the different levels of demand and different characteristics of the gas grid in these countries.[70]

Given the difficulty of estimating transport volumes we use the national demand as an indication of the cost of the grid per unit of gas. For 2023 using Eurostat national demand data, a cost of the gas grid of € 1.50 – 5.10/MWh was calculated, with an average of € 3.70/MWh.

A notable limitation of this approach is that some biomethane may be injected to the grid at the distribution level and be consumed on the distribution grid, leading to even further reduced volumes

[70] Each transmission network operator considered is the main or only operator in their respective country. Where other transmission network operators are present, e.g. France, Spain, Italy, the total allowed revenues for all transmission grid operators in the country is considered.

of gas transported on the transmission grid. This effect is not quantified in the cost estimate in this study, but is expected to have a modest effect on the expected cost of maintaining transmission grids per unit demand.