INDICATIVE INVESTMENT PLAN FLUXYS BELGIUM & FLUXYS LNG 2025-2034

September 2025

Contents

Purpose

The indicative investment plan for 2025-2034 outlines all necessary investments to keep pace with changes in Belgium's natural gas market, as well as to maintain and upgrade the infrastructure of Fluxys Belgium and Fluxys LNG[1], ensuring the achievement of targets set for reducing the installations' greenhouse gas (GHG) footprint.

The investments described in this document are provided for reference only and pertain to gas transmission and storage infrastructure in Belgium, along with the Zeebrugge LNG terminal.

Fluxys is dedicated to ensuring that new major investments are compatible with the energy transition, either by reducing GHG emissions or by constructing new multipurpose infrastructure.

This document has been prepared in accordance with Article 15/13, §2-3° of the Gas Decree dated April 12, 1965.

Compared to previous editions, this document no longer includes an annex describing the investment program related to hydrogen and carbon dioxide infrastructure. Two separate documents are now issued to reflect changes in the regulatory frameworks.

Outlook for 2025-2034

The projected investment in methane infrastructure for the period 2025-2034 totals €1,506 million[2]. This funding is primarily allocated to ensuring that the network remains robust, reliable, and aligned with future requirements. Currently, the reduction in natural gas consumption is limited, showing only a 2% decrease at the European level compared to the 2023 gas year. It will be essential to assess opportunities for repurposing or decommissioning infrastructure in order to adapt the network to evolving needs.

Market developments across Europe and within Belgium continue to necessitate targeted investments and modifications to Belgium's natural gas transmission network, ensuring it remains future-proof and consistent with the prior Indicative Investment Plan. Notable initiatives include preparatory work for a new jetty in

[1] Further in this document, 'Fluxys' stands for 'Fluxys Belgium and Fluxys LNG'

[2] This amount is only a small part (18%) of the overall investment program of Fluxys that includes also investments in hydrogen and carbon dioxide infrastructure. These investments are described in specific documents.

Zeebrugge and the construction of a second pipeline between Zeebrugge and Germany designed to accommodate hydrogen transport.

Fluxys Belgium maintains an unwavering commitment to safety, which requires ongoing investment in the maintenance, modification, and modernisation of its network. The company is also adapting its infrastructure to meet shifting demands from public distribution and industrial customers, factoring in both new connection requests and reductions in structural consumption resulting from improved building insulation and increased use of heat pumps.

The energy transition is accelerating and Fluxys Belgium and LNG plan to invest 1,506 million in keeping the current infrastructure resilient and ready for the future

Additionally, Fluxys continues to invest in digitalisation, integrates new molecules into its processes, and strives for continual operational improvements. Significant efforts are also underway to reduce both the company's CO_2 footprint and methane emissions, with a target of a 50% reduction in greenhouse gas emissions by 2025 compared to 2017 levels.

Fluxys Belgium is fully committed to supporting the energy transition. A key priority is maximising the reuse of existing natural gas infrastructure for the transport of alternative gases, and a repurposing strategy is presently being developed.

Policy objectives

European regulatory framework

In July 2024 were published:

- The Directive (EU) 2024/1788 of the European Parliament and of the Council on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive (EU) 2023/1791 and repealing Directive 2009/73/EC;
- The Regulation (EU) 2024/1789 of the European Parliament and of the Council on the internal markets for renewable gas, natural gas and hydrogen, amending Regulations (EU) No 1227/2011, (EU) 2017/1938, (EU) 2019/942 and (EU) 2022/869 and Decision (EU) 2017/684 and repealing Regulation (EC) No 715/2009.

These legislative measures will supersede the 3rd Gas Directive—following their transposition into national law by 4 August 2026—and the 2nd Gas Regulation from 4 February 2025. They will introduce a regulated framework for the European renewable gas and hydrogen markets, closely mirroring the existing framework for natural gas. Notable adaptations include updates to the network development plan, enhanced transparency regarding authorised revenues of network operators, and adjustments concerning gas quality.

According to the provisions outlined in the aforementioned Directive, transmission system operators and hydrogen network operators are required to submit a ten-year network development plan to the relevant regulatory authority at least every two years. This submission, informed by consultation with key stakeholders, must be based on current and projected supply and demand. The plan should detail both planned investments and identify infrastructure that may be repurposed or decommissioned.

Member States may choose to develop separate network development plans for natural gas and hydrogen, or opt for an integrated plan covering both. Each energy carrier must be modelled independently, with dedicated sections illustrating network maps for natural gas and hydrogen, respectively.

Furthermore, Member States are encouraged to coordinate the planning stages of their respective ten-year network development plans for natural gas, hydrogen, and electricity. All network development plans must align with integrated national and European energy and climate objectives, specifically supporting the goal of climate neutrality.

The ten-year network development plan for natural gas must incorporate effective measures to ensure system adequacy and security of supply.

Additionally, these plans will be made publicly available on a designated website, alongside the outcomes of stakeholder consultations.

Belgian regulatory framework

Belgium's Gas Act and Hydrogen Act set out rules for developing natural gas and hydrogen networks. A Royal Decree published on 12 May 2024 outlines procedures for preparing, approving, and publishing development plans for hydrogen and electricity transport networks. These rules closely follow a European Directive. The hydrogen transmission network operator must submit its 2028-2037 plan for ministerial approval by 1 July 2027. To fully implement the directive and regulation, Belgium will need to adapt both Acts accordingly.

Market Trend

European market trend

Annual Summary of the EU Gas Market (Gas Year 2024: Q4 2023 - Q3 2024) [3]

Gas Consumption

- Total EU gas consumption for the gas year **(Q4 2023 - Q3 2024)** amounted to **324 bcm**[4], reflecting a **2% decrease year-on-year** compared to the previous gas year.
- Seasonal variations were significant:
  - **Q4 2023:** 96 bcm, due to winter demand (+71% quarter-on-quarter, +1% year-on-year).
  - **Q1 2024:** 111 bcm, further increase compared to Q3 2023 driven by winter consumption (-2% year-on-year).
  - **Q2 2024:** 61 bcm, down **45% from Q1** due to the end of the heating season.
  - **Q3 2024:** 56 bcm, stabilizing demand (-9% from Q2, -0.3% year-on-year).
- Germany, Italy, and France remained the top gas consumers.

Gas Production

- **Annual domestic production: 31.5 bcm**, covering around **10% of EU consumption**.
- Declined consistently across the gas year:
  - **Q4 2023:** 8 bcm (-28% year-on-year).
  - **Q1 2024:** 8 bcm (-26% year-on-year).
  - **Q2 2024:** 7.7 bcm (-18% year-on-year).
  - **Q3 2024:** 7.8 bcm (-13% year-on-year).

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[3] This paragraph is a summary of the quarterly reports issued by the European Commission on gas markets: see https://energy.ec.europa.eu/data-and-analysis/market-analysis_en. Please note that the report for the fourth quarter of 2024 is not available at the moment of edition of this investment plan. That is the reason why the gas year (October 2023 to September 2024) is used for this document.

[4] Bcm states for "Billion Cubic Meter", usually used to refer to normalized gas volume quantities. Normalized means that the gas quantity is considered at the temperature and pressure conditions 0°C and 1 bar.

- The Netherlands and Romania were the largest producers, followed by Germany and Italy.

Gas Imports

- **Total imports for gas year 2024: 268 bcm**, marking an **8% decline year-on-year**.
- **Pipeline gas vs. LNG:**
  - Pipeline imports accounted for **67%** of total imports.
  - LNG imports made up **33%**, showing a consistent decline throughout the year.
- **Key suppliers:**
  - **Norway (33%)** remained the largest supplier.
  - **Russia (20%)** saw an increase in market share despite EU diversification efforts.
  - **U.S. (13%)** was the top LNG supplier.
  - Other contributors: North Africa (13%), Azerbaijan (4%), Qatar (4%).

Gas Storage

- EU storage levels remained **historically high**, reaching **90% of capacity ahead of winter, as required by European rules, despite a decrease of 11 bcm in storage compared to previous gas year, resulting in an equivalent decrease in the gas imports**.
- **Quarterly trends:**
  - **Q4 2023:** Storage peaked at **95%**, well above historical norms.
  - **Q1 2024:** Declined to **68%** due to withdrawals.
  - **Q2 2024:** Average filling rate at **67%**, slightly above Q2 2023.
  - **Q3 2024:** Storage levels at **88%**, with strong summer injections.

Gas Prices

- **Wholesale prices:**
  - **Q4 2023: €41/MWh**, up **24% from Q3 2023**, but **57% lower than Q4 2022**.
  - **Q1 2024: €27.3/MWh**, the lowest since 2021 (-49% year-on-year).
  - **Q2 2024: €32/MWh**, up **16% from Q1**, but **10% lower year-on-year**.
  - **Q3 2024: €36.2/MWh**, reflecting **geopolitical concerns** (+12% quarter-on-quarter, +7% year-on-year).
- **Retail prices:**
  - **Average for gas year 2024: €103/MWh**.

    - Dropped by **20% year-on-year in Q1**, followed by smaller reductions.
    - Q3 saw a **2% increase quarter-on-quarter** but **3% decline year-on-year**.

Global Market & Geopolitical Factors

- **LNG Market:**
    - The EU was the **third-largest LNG importer globally** (16% market share), behind China and Japan.
    - **U.S. remained the dominant supplier (40%)**, though LNG imports **declined throughout 2024**.
- **Russia's Role:**
    - Russian gas **accounted for 20% of EU imports**.
    - Despite a **64% decline compared to pre-war levels (2021)**, its market share slightly increased compared to previous year.
- **Geopolitical events:**
    - **Conflict in Ukraine** continued to impact gas flows.
    - EU policies pushed for **energy diversification and renewable integration**.

Conclusion

- **Gas year 2024 (Q4 2023 - Q3 2024) was marked by slightly declining gas demand due to a mild winter**, **lower LNG reliance**, and **high storage security**.
- Prices **remained volatile** but trended lower than in 2022, driven by **policy shifts (a.o. storage rules) and mild weather conditions**.
- The EU **successfully managed winter demand** while continuing its **transition toward energy independence and decarbonization**.

Belgian market demand

H-gas capacity offer

Since the Ukrainian crisis, gas flows have shifted direction: whereas flows historically moved from East to West, since 2022, they now originate primarily from the West (notably LNG sources and Norwegian gas) and are directed mainly towards the East. As a result, capacity offerings have been reallocated to better match market demand, enabling maximum eastbound transit while ensuring suitable levels remain available for neighbouring countries.

Recent investments in the Desteldonk-Opwijk pipeline have facilitated an increase in Entry capacity at the Zeebrugge area. This enhancement supports higher domestic peak H-gas consumption following the cessation of L-gas use in Belgium on 01/09/2024 and meets the requirements of new CRM power plants expected to become operational in late 2025, in addition to sustaining flows primarily towards Germany.

As of 01/01/2025, the send-out capacity at the Zeebrugge LNG Terminal has also risen to 30.2 GWh/h.

Details regarding the maximum Entry Firm capacity as of 01/01/2025 are provided in the table below.

Adjacent country(ies)	**Max. Entry Firm capacity[5] at 1/1/25 [GWh/h]**
from Norway	20.35
Other (LNG)	30.2
from UK	27.15
from France	11.3
from the Netherlands	33.4
from Germany	20.15

Maximum Exit Firm capacity on 01/01/2025 is given in table hereunder:

Adjacent country(ies)	**Max. Exit Firm capacity[6] at 1/1/25 [GWh/h]**
towards UK	33.5
towards France	15
towards the Netherlands	17.85
towards Germany	23.5

Projects arising from additional investments are currently underway to enhance Entry capacity, Exit capacity, or both simultaneously:

- A new supply point from Loenhout to the Limburg region is under development, with commissioning now projected for November 2025.

[5] Offered capacity may be different.

- Expansion of the backbone network in western Belgium will connect Desteldonk with Knokke-Heist in the Zeebrugge area, with commissioning anticipated in 2026.

The allocation of the increased capacity will occur on the Commercial Start Date to align with market requirements.

H-gas entry capacity subscriptions

Figure 1 gives the total booked (Firm + Interruptible) Entry capacity per Adjacent Country.

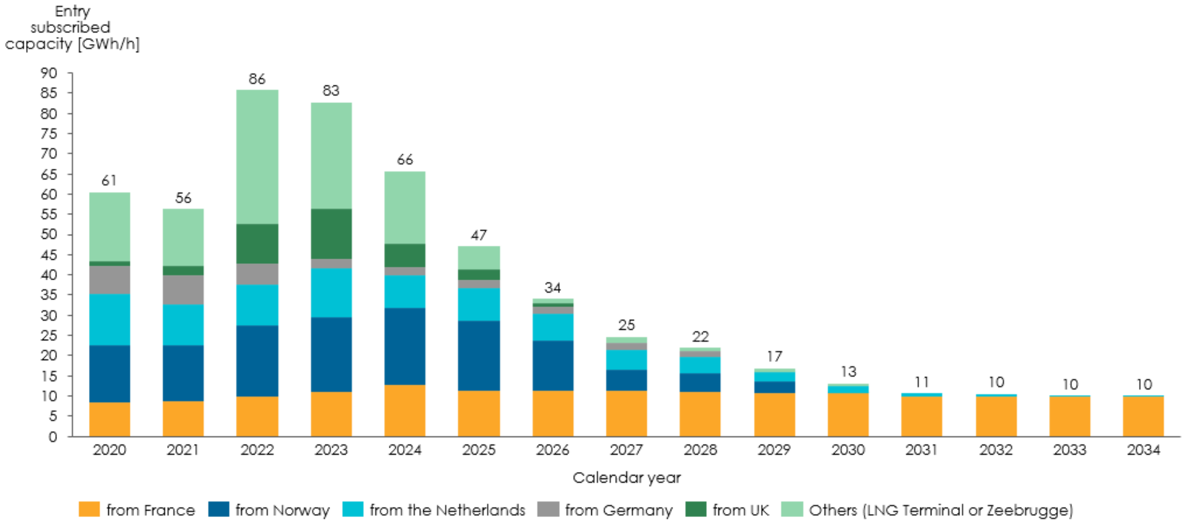

FIGURE 1 - BOOKED ENTRY CAPACITY (FIRM + INTERRUPTIBLE) PER ADJACENT COUNTRY

In 2024, total booked Entry capacity dropped to 66 GWh/h (excluding Loenhout Storage), returning to pre-Ukrainian crisis levels after the spike in 2022 and 2023. Entry capacity from Norway and France is secured through long-term contracts, while UK Entry bookings fluctuate based on NBP-ZTP spreads and market conditions.

Figure 2 shows total Firm and Interruptible Entry capacity by Product Runtime.

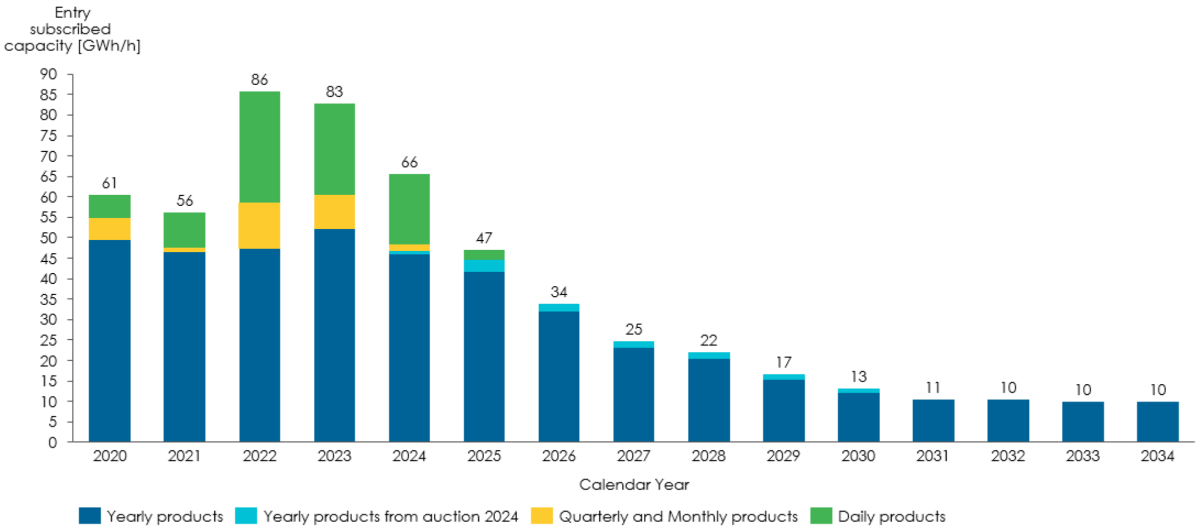

FIGURE 2 - BOOKED ENTRY CAPACITY (FIRM + INTERRUPTIBLE) PER PRODUCT RUNTIME

While Long-term booking levels appear to decline beginning in 2026, this does not indicate a reduction in capacity requirements. Rather, it reflects a market trend shifting from long-term bookings toward shorter-term arrangements.

H-gas exit capacity subscriptions

Figure 3 gives the total booked Firm + Interruptible Exit capacity per Adjacent Country.

In 2024, total Firm + Interruptible Exit capacity bookings dropped to 62 GWh/h (excluding Loenhout Storage), following high activity in 2022–2023. This figure remains over 50% above pre-Ukrainian crisis levels, mostly due to increased bookings to Germany and the Netherlands, which account for more than half of all bookings from 2022 to 2025. By 2027, Exit Capacity subscriptions to France fall below 5 GWh/h.

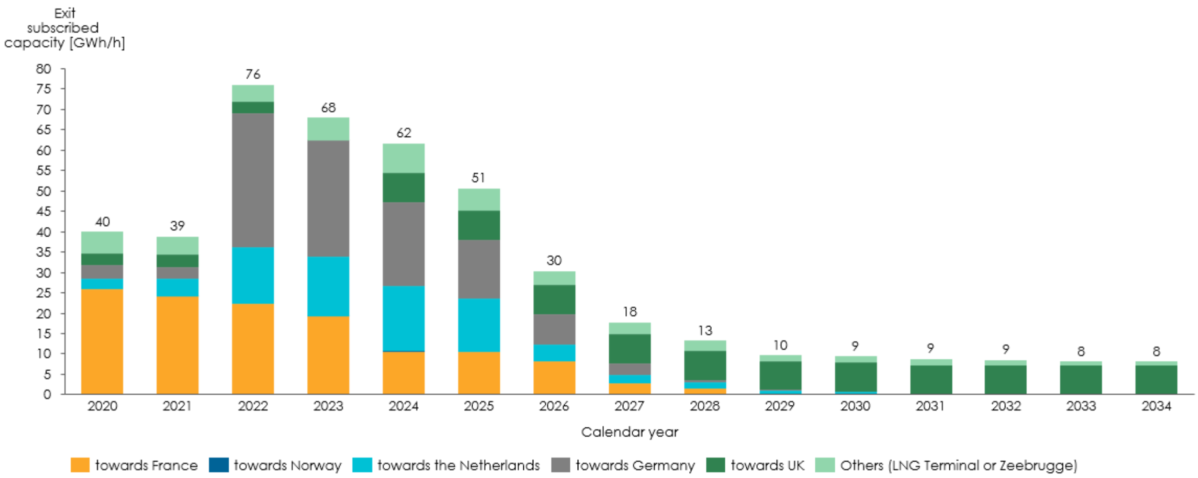

FIGURE 3 - BOOKED EXIT CAPACITY (FIRM + INTERRUPTIBLE) PER ADJACENT COUNTRY

Figure 4 gives the total booked Firm + Interruptible Exit capacity per Product Runtime.

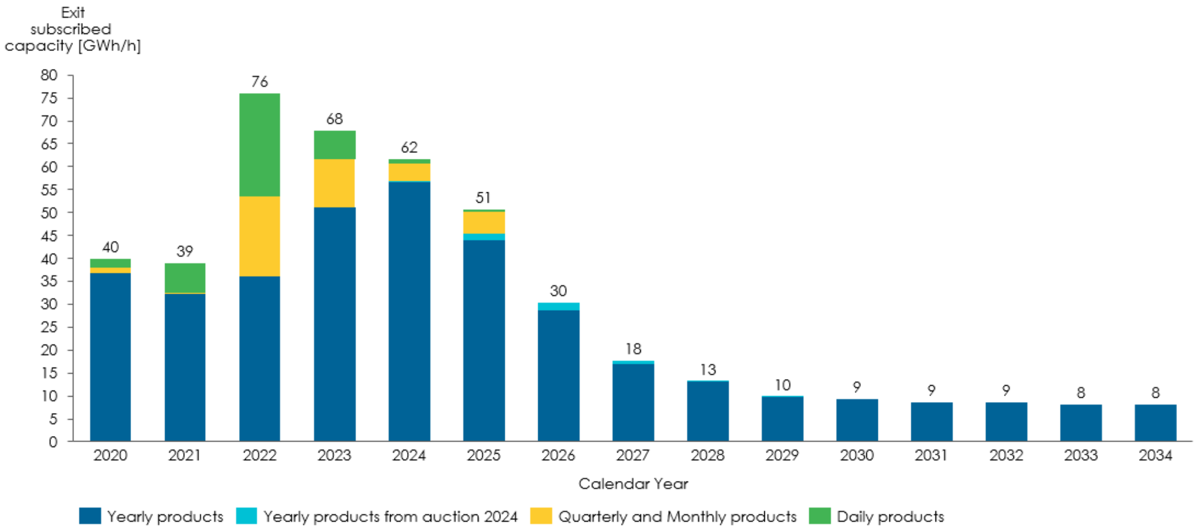

FIGURE 4 - BOOKED EXIT CAPACITY (FIRM + INTERRUPTIBLE) PER PRODUCT RUNTIME

Despite the market trend toward shorter-term subscriptions, yearly bookings grew from 2023 to 2025 as shippers sought to secure capacity to the Netherlands and Germany for several years due to the Ukrainian crisis.

L-gas capacity offer

Figure 5 gives the booked Firm capacity per Interconnection Point L-gas.

As of 01/09/2024, Belgium has completed the L to H gas conversion and no longer uses L-gas domestically. However, L-gas is still needed in northern France until at least 2028, so transit through Belgium will continue. Entry capacity at Hilvarenbeek-L is fully booked long-term, with no extra bookings expected based on current consumption. Historical exit contracts ended in January 2024; since then, Blaregnies-L exit capacity is booked mostly short-term, resulting in lower average bookings for 2024 and 2025.

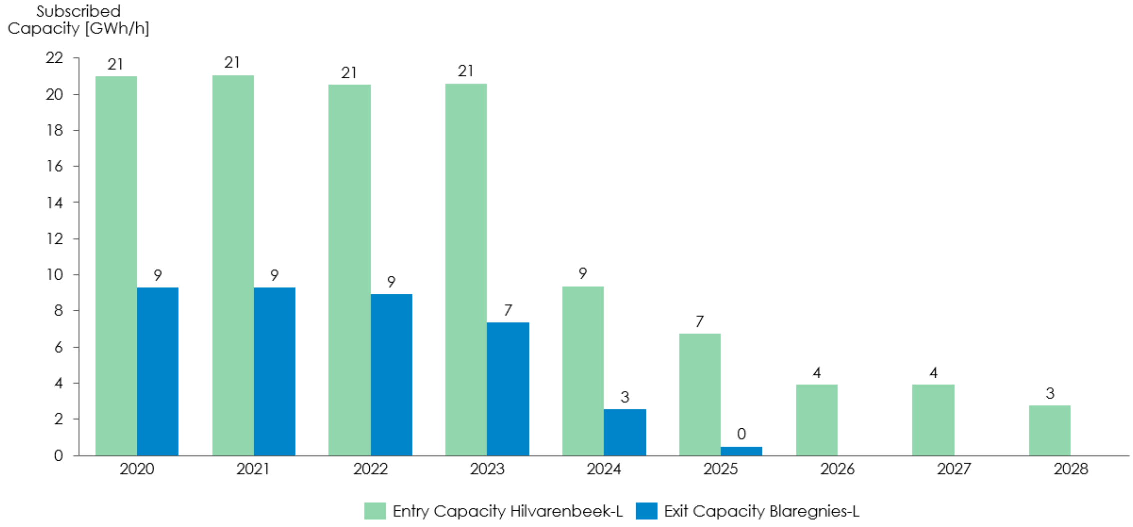

FIGURE 5 - BOOKED FIRM CAPACITY PER INTERCONNECTION POINT L-GAS

Gas flows

Fluxys Belgium and Fluxys LNG natural gas infrastructure

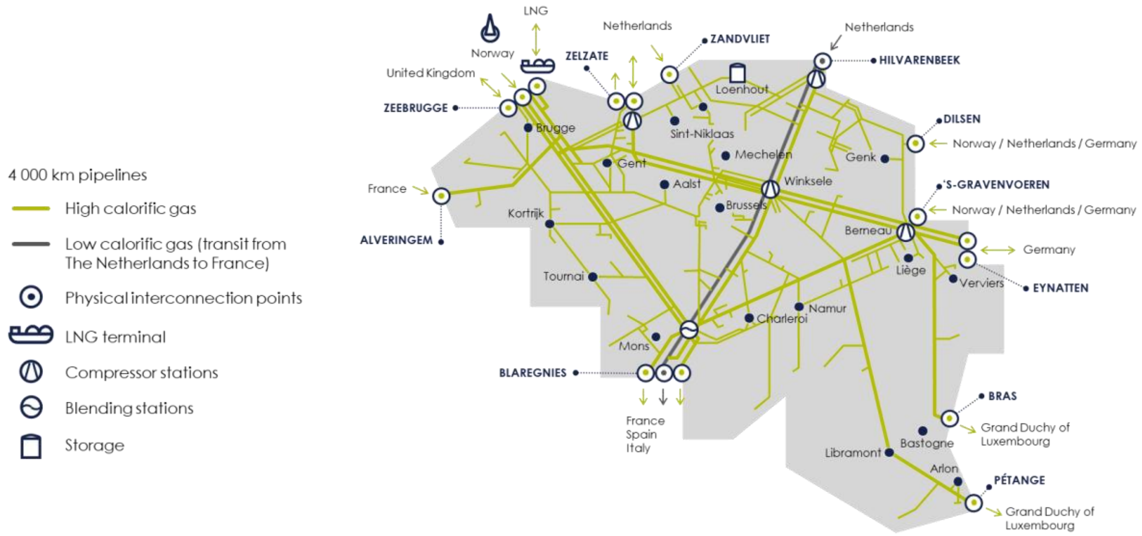

FIGURE 6: FLUXYS BELGIUM AND FLUXYS LNG NATURAL GAS INFRASTRUCTURE

Belgium's natural gas supply is sourced from multiple origins, resulting in differences in chemical composition, heating value, and Wobbe index among the various types. Most supplied gases are classified as 'rich' gases, with a typical heating value of 11.3 kWh/Nm³, and are combined and transmitted as high-calorific natural gas (H-gas). Low-calorific natural gas (L-gas) from the Groningen gas field in the Netherlands contains up to 14% nitrogen, with a typical heating value of 10.3 kWh/Nm³. This type of gas is not interchangeable with H-gas due to its lower heating value. Consequently, Fluxys Belgium operates two[7] separate transmission networks for these gas types.

Market segments

The Belgian transmission system supplies gas to three market segments (or categories of end users):

- Distribution networks, which supply residential customers, SMEs, and the tertiary sector
- Industrial customers, including large-scale combined heat and power (CHP) generation facilities.
- Power plants

The market share per segment varies constantly, according to very different offtake profiles:

- Consumption **in the distribution network** is strongly influenced by the weather conditions.
- **Industrial customers** have a regular offtake pattern.
- **Power plants** withdraw gas to accommodate fluctuations in demand, which are increasingly volatile. Although electricity demand is generally less sensitive to temperature changes (this could change in the future) than natural gas demand, factors such as the availability of alternative energy sources (including nuclear, solar, wind, and cross-border imports/exports) and economic considerations (such as the spark spread between coal and natural gas) exert considerable influence.

Consumption trends in Belgium

Change in the number of degrees days

[7] The migration of L-gas consumers to H-gas in Belgium has been completed on September 1st, 2024. Only one pipeline will remain in operation, in Belgium, for L-gas to transport L-gas from The Netherlands to France until full migration of the L-gas consumers in France.

The number of degree days in a year indicates heating needs, with 2252 equivalent degree days set as the benchmark[8]. Years with fewer degree days are considered warm, those with more are cold. Figure 7 shows the 2015–2024 average is 2070—well below the benchmark. The last three years (2022–2024) are even lower, marking them as some of the warmest in the past decade, which has supported progress toward European Commission reduction targets.

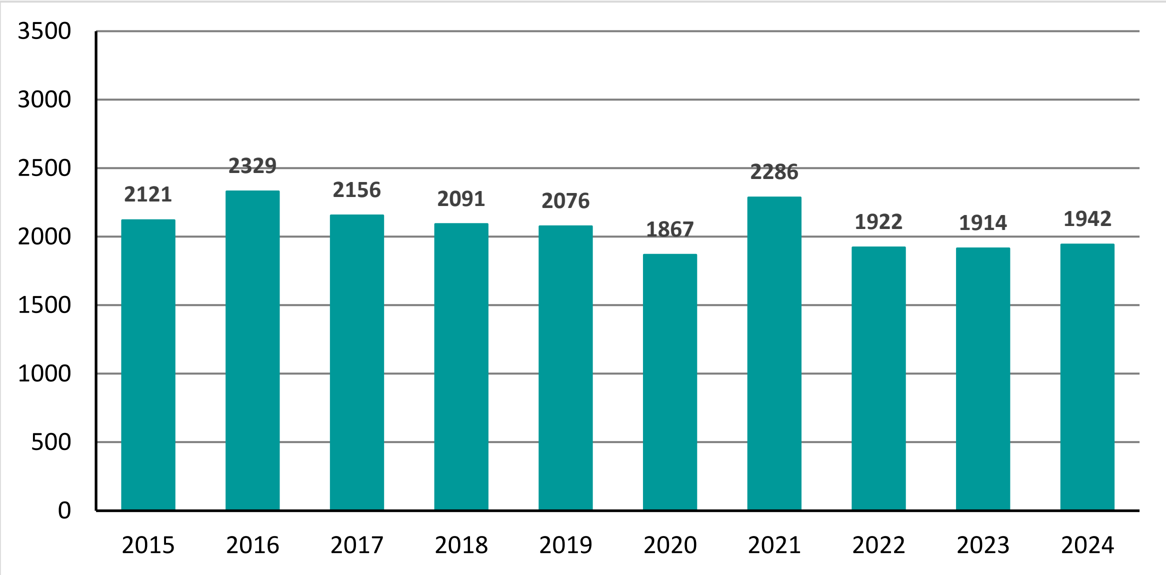

FIGURE 7: EQUIVALENT DEGREE DAYS (CALENDAR YEAR)

Annual volumes for the Belgian market

In this chapter, all figures refer to “Calendar Years”.

There was a gradual increase in offtake up to 2019, primarily due to higher demand from power plants and industrial customers. Total consumption remained stable in 2020 and 2021. However, low levels of stored gas reserves in Europe contributed to an increase in gas prices at the end of the year, coinciding with the Ukraine crisis. In August 2022, the European Council implemented a 15% reduction in gas consumption (compared to the average from April 1st, 2017, to March 31st, 2022), resulting in a decrease in annual consumption for 2022. This reduction target was extended from March 2023 to March 2024, and the reduction in consumption by public distribution and industry, which began with higher gas prices in Q3 2022, continued into 2024.

[8] 1991 to 2020, Synergrid benchmark (calendar year). For a given day, the degree day is the difference between 16,5°C (reference in Belgium) and the average temperature of the day (NB: the degree day if the average temperature of the day is greater than 16,5°C is considered as zero). The sum for a given period of the daily degree days reflects the energy required to heat a building.

In 2024, Belgium's gas consumption declined further to 149 TWh, the lowest level in at least a decade. This decrease was mainly attributable to reduced gas use in power plants, falling from 32 TWh in 2023 to 24 TWh in 2024. Public distribution and industrial consumption experienced slight increases: public distribution rose to 82 TWh from 80 TWh in 2023, and industrial consumption increased to 43 TWh from 40 TWh in 2023. Overall, relative to the 2020-2021 period, demand in 2024 was over 20% lower.

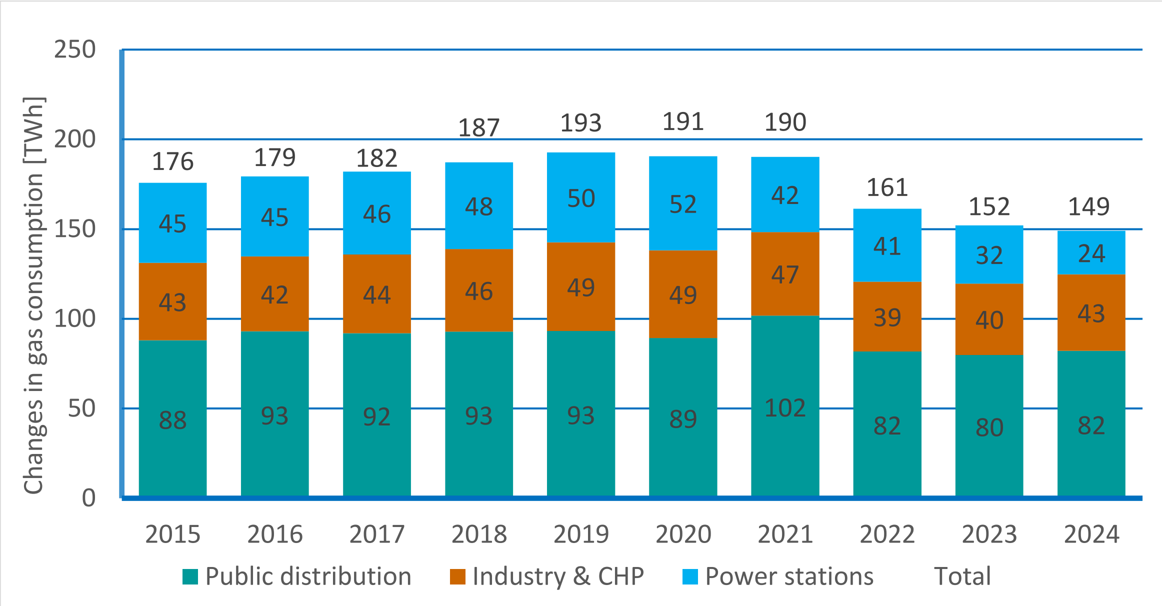

FIGURE 8: CHANGES IN GAS CONSUMPTION IN BELGIUM (IN TWH/YEAR)

Distribution Network

Consumption in distribution networks closely follows yearly temperature trends. Since Q3 2022, annual usage has dropped by over 15% due to higher gas prices and call from authorities for reduced consumption. Even as gas prices fell in 2023 and 2024, usage stayed at 2022 levels.

Industrial customers (including combined heat and power generation)

Since the 2008-2009 economic crisis, several major industrial consumers have ceased operations, including the Opel car plant in Antwerp (late 2010), the steel plant in Liège (late 2014), and the Ford car plant in Genk (late 2014). After the market downturn ended in 2014, industrial consumption increased by approximately 2.5% annually, reaching 49 TWh in 2020, aided by new connections. In 2021, consumption declined slightly due to rising gas prices in the last quarter, followed by a significant decrease beginning in 2022. As gas prices rose sharply, industrial offtake fell by more than 15%. Although wholesale gas prices dropped substantially compared to 2022, there were modest increases in 2023 and again in 2024. These changes reflected both a gradual market recovery and that 2024 price levels remained too high for some industries to operate at full capacity.

Power plants

The production of power plants is influenced by a diverse set of factors. The increasing share of renewables within the generation mix has had a significant impact. Furthermore, the offtake patterns of power plants have become more volatile, as highly flexible open-cycle gas turbines and efficient combined-cycle gas turbine (CCGT) units are increasingly deployed to support variable and uncertain power output from solar and wind sources. Additional key parameters include the availability of nuclear power plants, electricity demand from neighbouring countries, and prevailing energy prices. Notably, there was a marked reduction in gas-fired power plant offtake, with 2024 consumption falling to 46% of its 2020 level, indicating that the market has sourced more cost-effective electricity from neighbouring regions. In contrast to previous years, Belgium has transitioned to being a net importer of electricity.

The reduced gas consumption observed at existing gas-fired power plants results primarily from increased renewable generation. This trend is expected to persist, as gas-fired generation is anticipated to play an enhanced role in balancing the volatility inherent to renewable energy sources. The availability of gas-fired power generation capacity will therefore be crucial in ensuring electricity supply during periods of insufficient renewable production (dunkelflaute).

Overview of annual allocations at border points (grouped by country)

The overview in this section covers the period up to and including 2024.

The figure below presents a schematic overview that illustrates the average volumes imported and exported (allocations) during 2020-2024. The size of each arrow corresponds to the respective volume at each border. For information about capacity subscriptions, please refer to the H-gas capacity offer page 10.

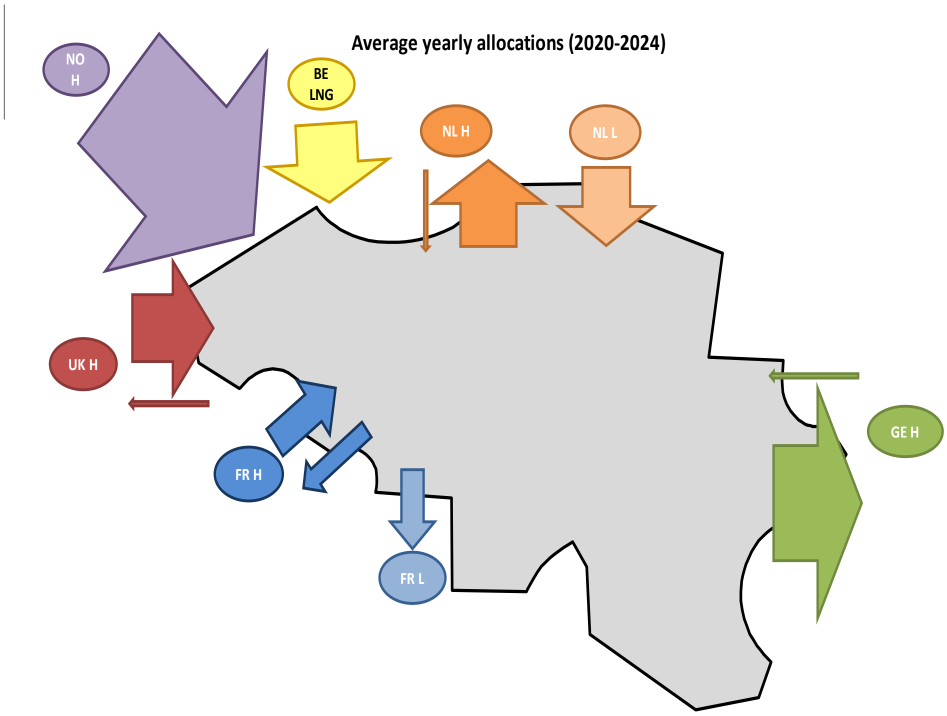

FIGURE 9: ALLOCATIONS AT BORDER POINTS, 2020-2024

Natural gas imports

In 2024, the total gas volume entering the Fluxys Belgium network dropped to 394 TWh, remaining about 50 TWh above 2020 and 2021 levels, after peaks of 587 TWh in 2022 and 498 TWh in 2023.

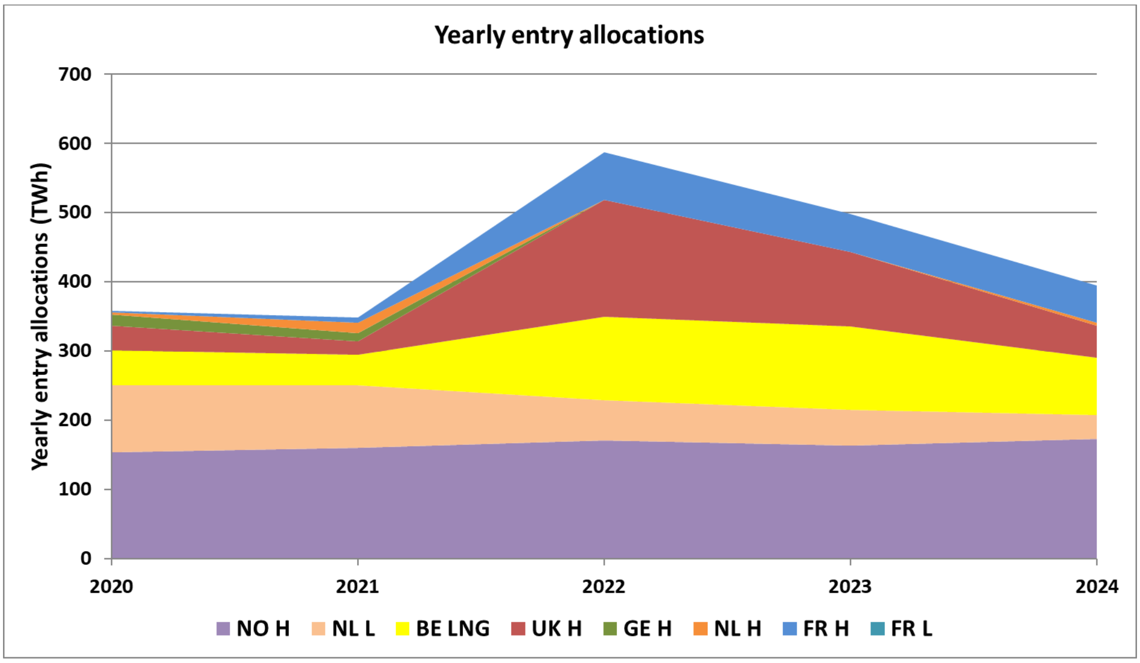

FIGURE 10: ANNUAL ENTRY ALLOCATIONS

Key Supply Routes

- **Norwegian Pipeline (Zeepipe):** Continues to serve as Belgium's principal supply route, delivering consistently stable volumes ranging from 150 to 175 TWh between 2020 and 2024.
- **Dutch Gas Supplies:**
  - **H-gas:** Volumes have shown a continuous decline since 2019.
  - **L-gas:** Phased out in Belgium as part of the L-H conversion process, which concluded in September 2024. Going forward, L-gas from the Netherlands will only transit through Belgium to serve the French market, where conversion is scheduled for completion in 2028.
- **UK Imports:** Typically range from 25–50 TWh per annum; however, a significant increase was observed in 2022 due to reduced Russian gas availability. While imports remained above typical levels in 2023, they did not match those of 2022. In 2024, UK imports stabilized at 47 TWh.
- **LNG & French Supply:** Imports have increased, albeit to a lesser extent compared to other sources, reflecting ongoing shifts in supply dynamics.
- **German Imports:** Historically low even prior to 2022, with almost all volumes sourced from the former Gaspool market area.

Natural gas exports

From 2020 to 2021, Belgium exported an average of 150–200 TWh of natural gas (both L- and H-gas) annually to neighbouring markets. In 2022, exports rose significantly to over 400 TWh, primarily due to increased demand resulting from the energy crisis. Although volumes decreased to approximately 350 TWh in 2023, they remained double the levels observed prior to 2022. By 2024, export levels stabilized at 250 TWh, representing a midpoint between 2023 figures and those recorded during 2020–2021.

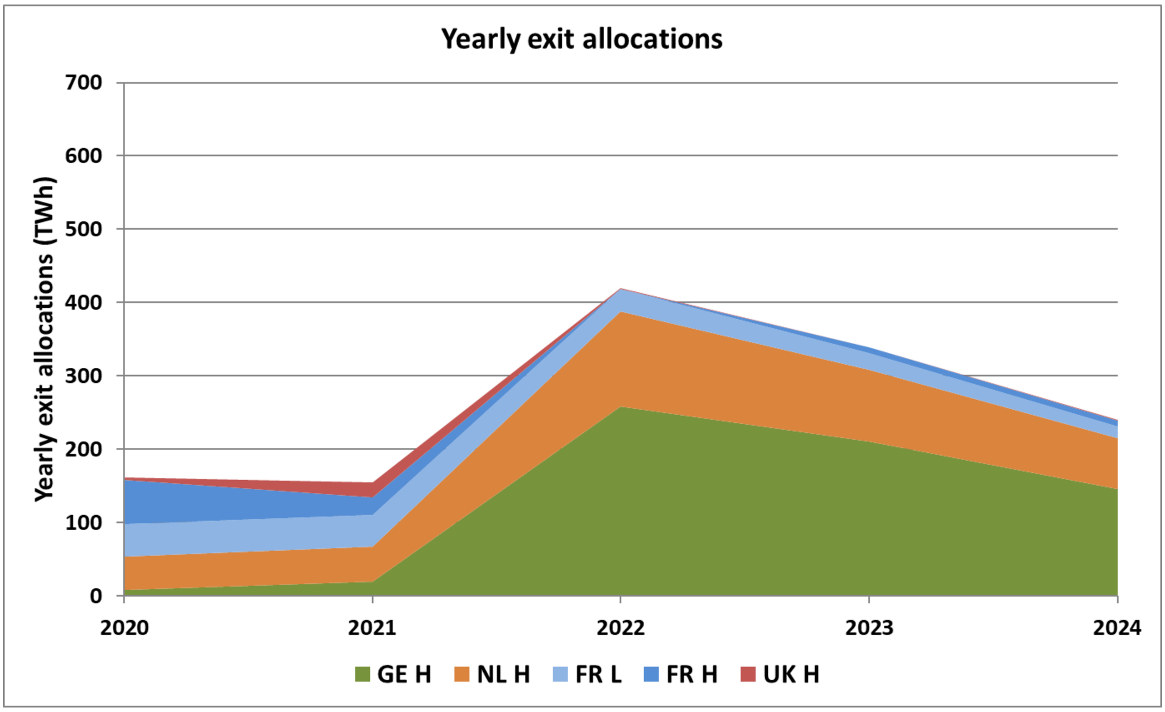

FIGURE 11: ANNUAL BORDERS EXIT ALLOCATIONS

Key Export Destinations

- **France:** Has represented 50–80% of Belgium's gas exports in recent years.
  - **L-gas:** Remained steady at approximately 50 TWh per year.
  - **H-gas:** Decreased substantially, with only small quantities recorded from 2022 onward.
- **UK:** Exports decreased before 2020 and have not returned to previous levels.
- **Germany & Netherlands:** Imports from Belgium increased significantly in 2022 and continued at lower volumes in 2023 and 2024, a trend linked to reduced Russian supply by pipeline. The total exported volumes to Germany and the Netherlands in 2024 (for example: 53 TWh in 2021, 308 TWh in 2023, and 215 TWh in 2024) are still considerably higher than pre-Ukraine crisis figures.
- **Luxembourg:** Figures are not included, as Belgium and Luxembourg function as a single entry/exit market for H-gas.

Fluctuations in daily allocations at border points

Fluxys Belgium monitors daily and hourly network flows to assess how market participants use available capacity for neighbouring networks. Based on this analysis, capacity reallocations may be considered and proposed as needed.

Natural gas imports

Figure 12 shows daily gas flow changes at various Fluxys Belgium border points from 2020 to 2024. Average injections were 40-45 GWh/h in 2020–2021, peaking at 70 GWh/h. In 2022 and early 2023, total injected volumes rose sharply, with peaks over 80 GWh/h—levels last seen in 2018. Entry volumes declined in late 2023 and 2024. Notably, large allocations in 2022–2023 came mainly from the UK Interconnector, Zeebrugge LNG Terminal, and Alveringem (FR H), reflecting shifts in flow patterns due to reduced east-west flows following the Ukraine crisis.

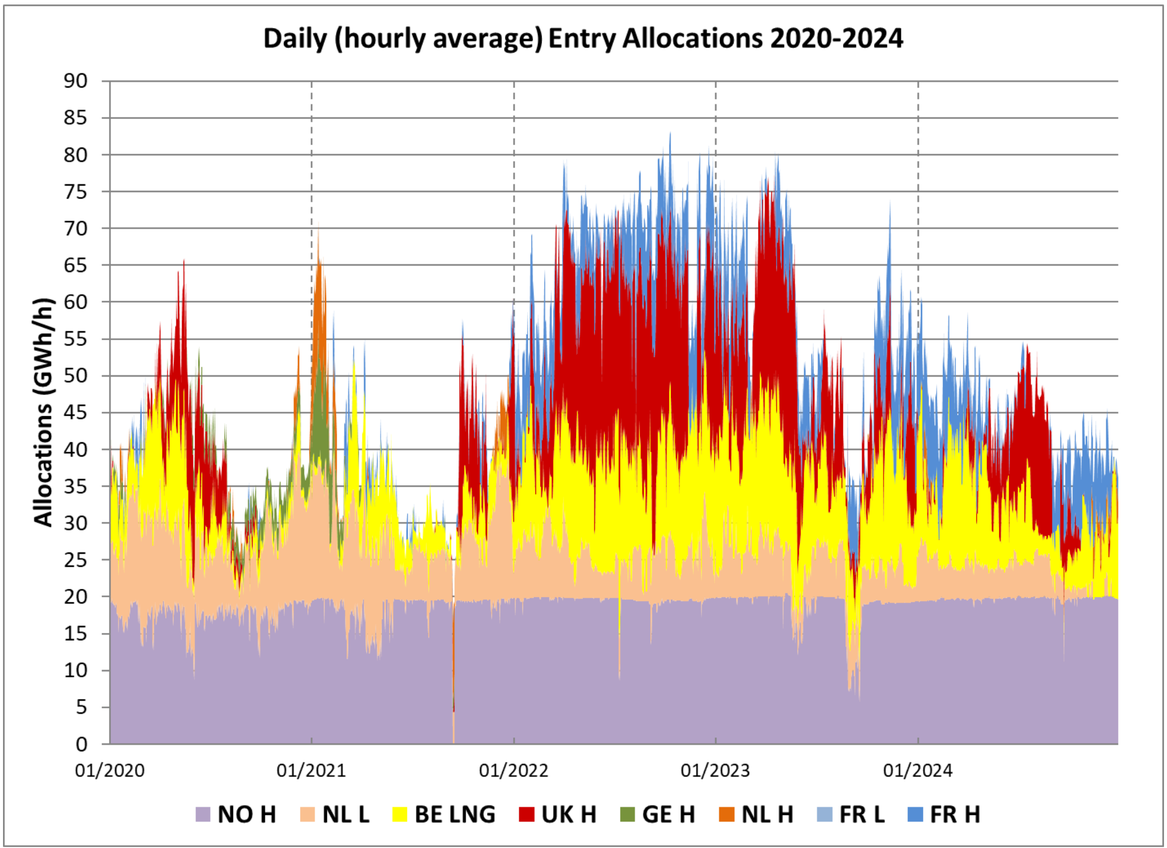

FIGURE 12: DAILY ENTRY ALLOCATIONS

Figure 13[9] below provides details of the use of injected capacity in 2020-2024.

[9] This graph is based on a calculation of the daily net value of the allocations.

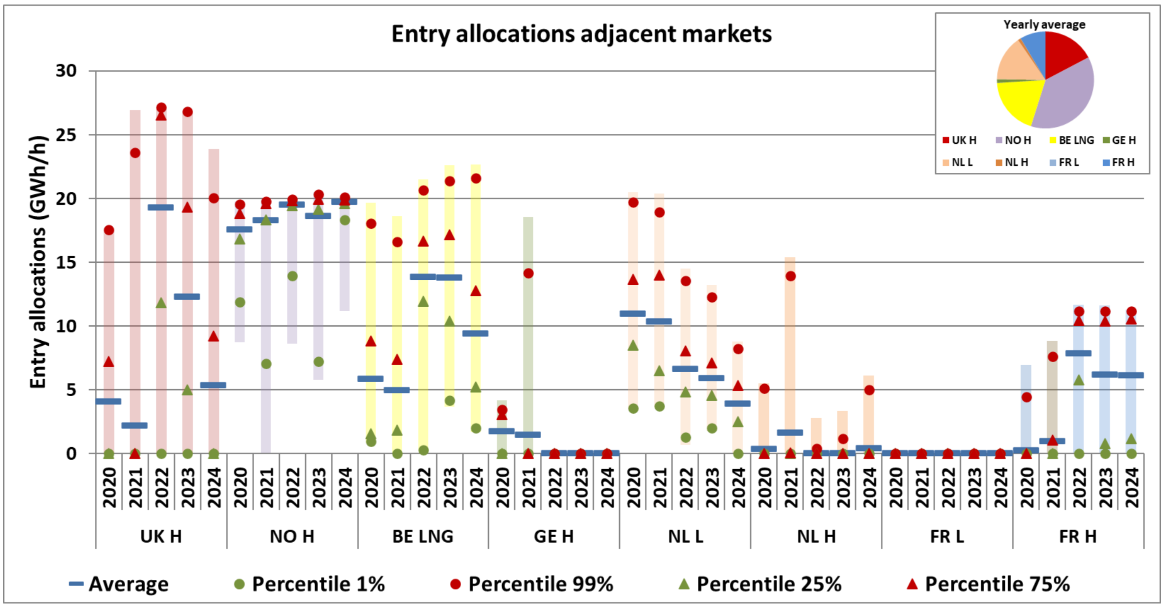

FIGURE 13: ENTRY ALLOCATIONS, NEIGHBOURING MARKETS

Recent investments, such as the Desteldonk-Opwijk pipeline, have ensured that the H-gas network's import capacity can meet anticipated domestic demand increases from L/H conversion and new power plants, despite flow changes due to the Ukraine crisis.

Natural gas exports

Figure 14 shows the change in daily flows simultaneously exiting various border points on the Fluxys Belgium network (2020-2024).

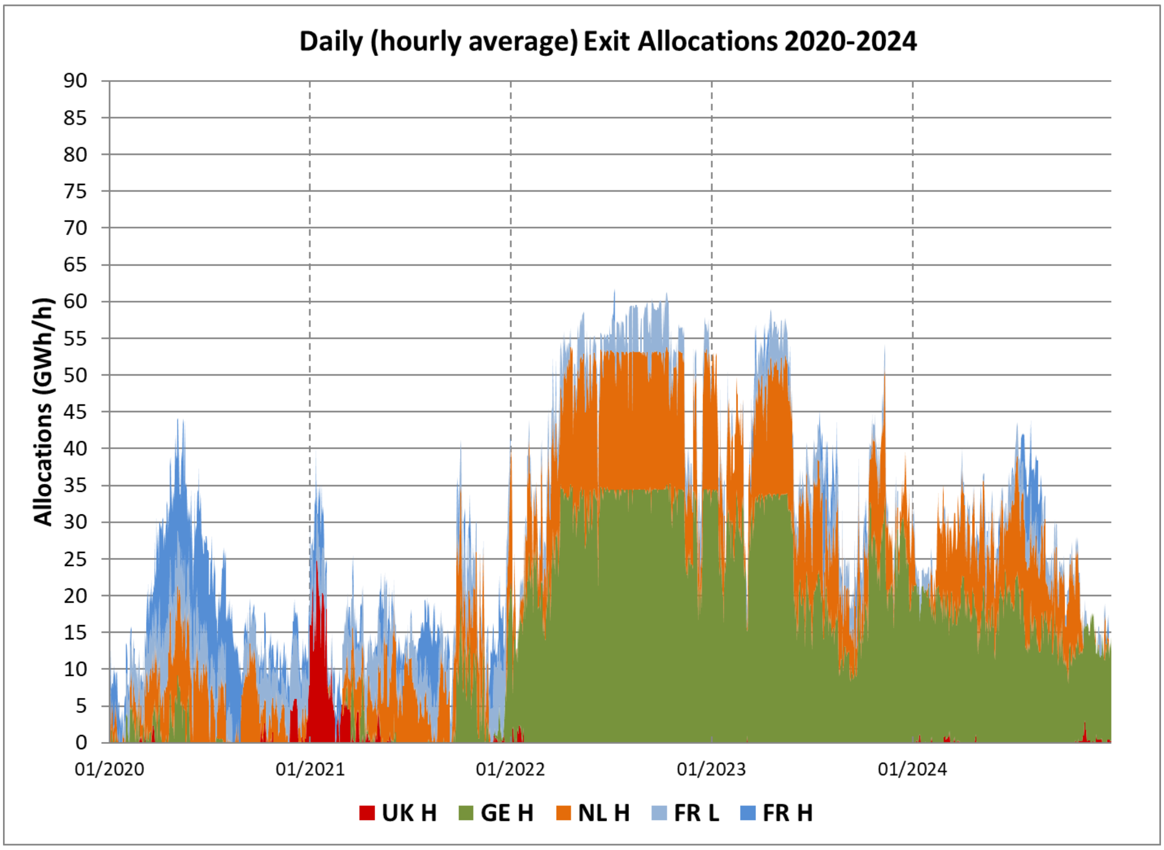

Figure 14: Daily borders exit allocation

During 2020-2021, an average of 17 to 24 GWh/h was transported to neighbouring countries. There were increased flows to the UK during the winter of 2020-2021. In 2022, new peak flows of up to 60 GWh/h were observed. These higher flows resulted from reduced pipeline imports of natural gas from Russia and low levels of stored gas in Europe at the beginning of the winter 2022-2023 period. The Fluxys Belgium network operated without issues during this period of increased transmission. The latter parts of 2023 and 2024 have seen a decrease in exit volumes, although they remain relatively high. This reduction is attributed to the European Commission's target to lower energy consumption by 15% between March 2022 and March 2024, the integration of new floating storage and regasification units (FSRUs) into the German grid, and requirements to fill gas storage facilities to 80% before winter 2022-2023 and to 90% for subsequent winters.

Figure 15[10] below provides an overview of the use of capacity supplied to each market area in 2020-2024.

[10] This graph is based on a calculation of the daily net value of the allocations.

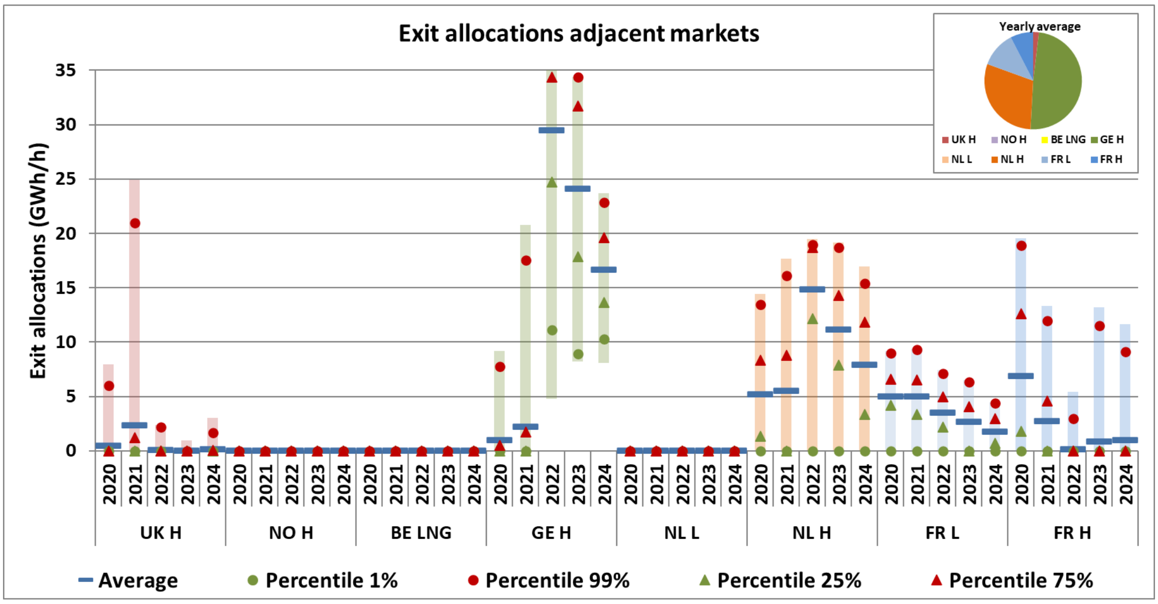

FIGURE 15: EXIT ALLOCATIONS, NEIGHBOURING MARKETS

Until 2021, the highest average daily gas flow was directed to the French market (including both H- and L-gas). The French market also exhibited an average value closest to peak consumption, indicating a higher load factor. Beginning in 2022, flows to Germany and the Netherlands increased substantially, while transport to France declined, particularly for the H-gas segment.

Scenarios

Scenarios from TYNDP ENTSOE/G

Scenarios Report

Scenario storylines

As in previous editions, ENTSOG TYNDP 2024 begins with the development of European multi-energy supply and demand scenarios. In line with Regulation (EU) No 347/2013, the ENTSOs for gas and electricity released a draft joint Scenarios Report[11] in May 2024. Three distinct future energy scenarios were created to assess the infrastructure needs of Europe's integrated energy system.

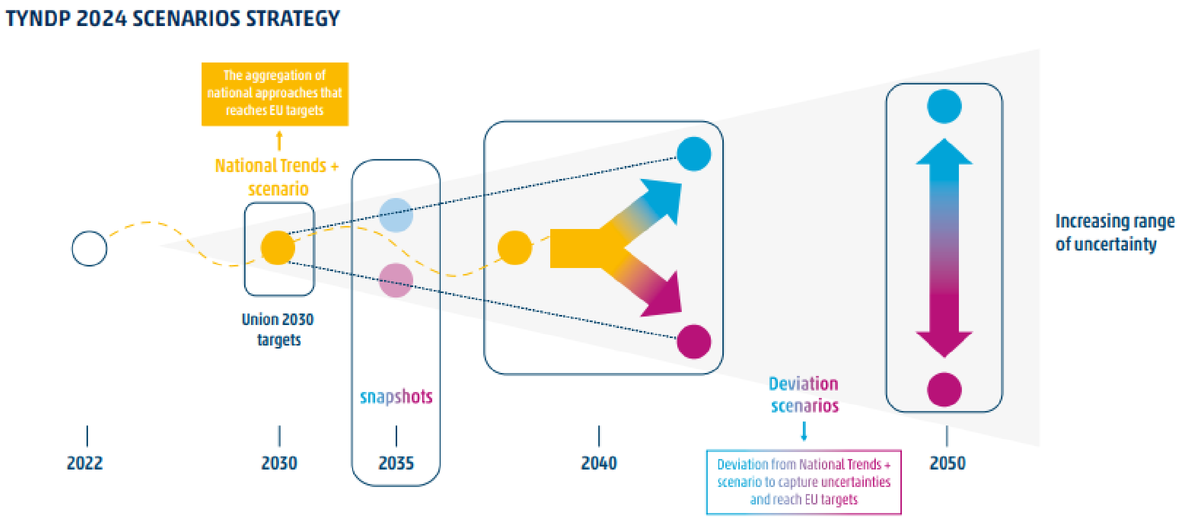

FIGURE 16 : SCENARIOS STRATEGY (SOURCE: ENTSO-E // ENTSOG TYNDP 2024 DRAFT SCENARIOS REPORT – MAY 2024)

The National Trends + scenario reflects national energy and climate policies based on European targets, with joint data from gas and electricity TSOs for 2030 and 2040. Distributed Energy and Global Ambition are broader, top-down scenarios for 2040 and 2050, aligned with Paris Agreement net zero goals. Distributed Energy emphasises decentralisation and European autonomy, while Global Ambition prioritises centralised low-carbon and renewable options, positioning the EU as a leader in the global energy transition.

Demand

The EU's final energy demand is projected to drop sharply due to greater energy efficiency and increased system integration, such as building upgrades and hybrid heat-pumps.

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[11] https://2024.entsos-tyndp-scenarios.eu/

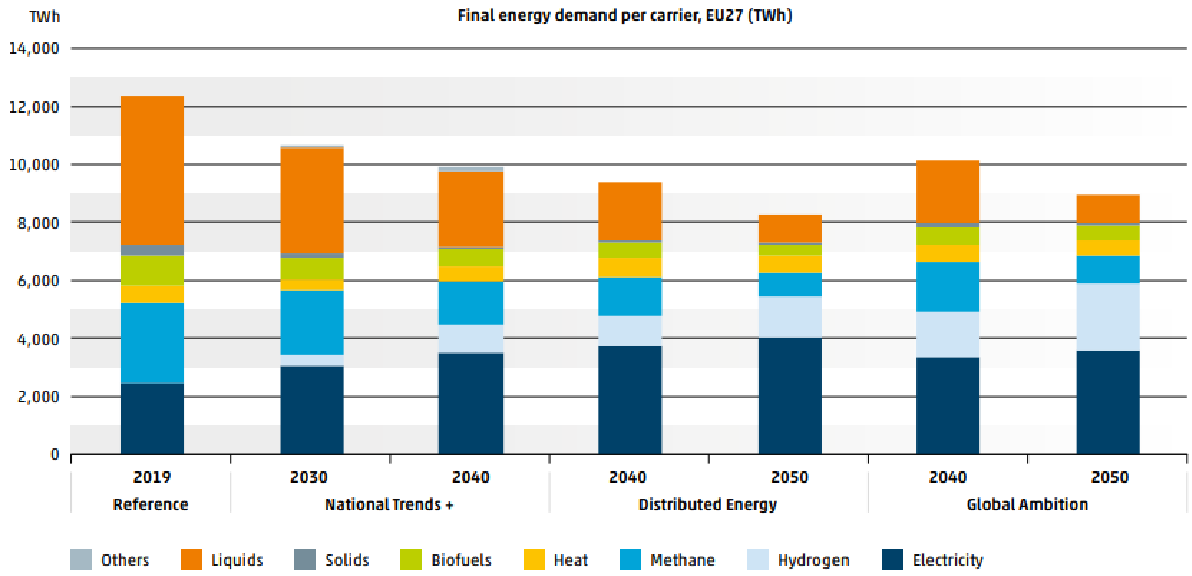

FIGURE 17 : FINAL ENERGY DEMAND PER CARRIER, EU27 (TWH) (SOURCE: ENTSO-E // ENTSOG TYNDP 2024 DRAFT SCENARIOS REPORT – MAY 2024)

Methane demand is expected to decrease, but it will remain essential for balancing energy markets through 2050.

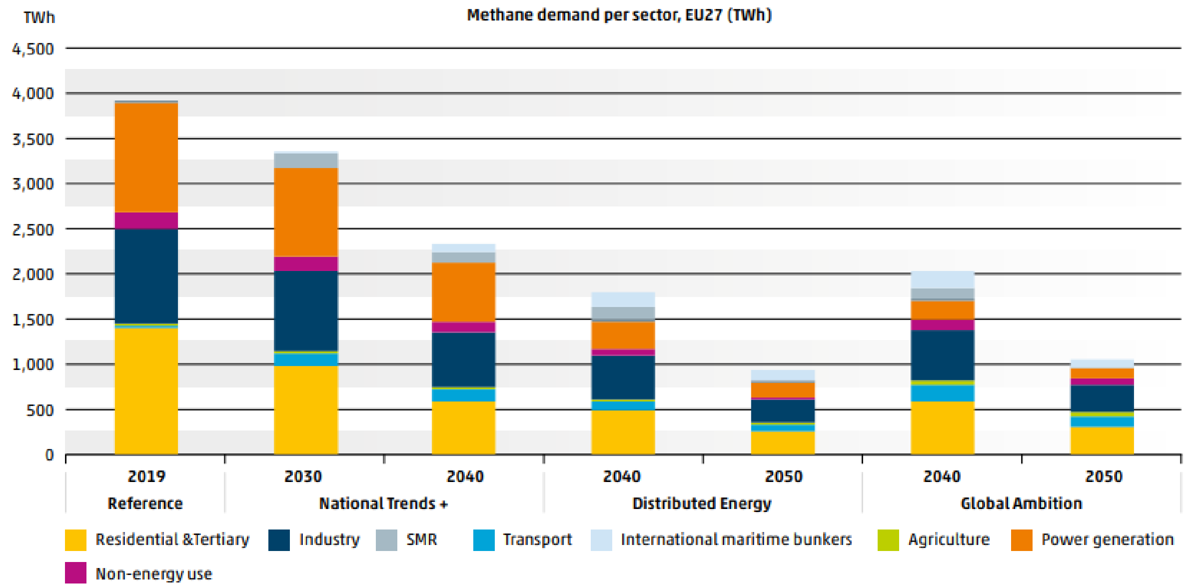

FIGURE 18 : METHANE DEMAND PER SECTOR, EU27 (TWH) (SOURCE: ENTSO-E // ENTSOG TYNDP 2024 DRAFT SCENARIOS REPORT – MAY 2024)

Demand for hydrogen is projected to increase from 2030, with hydrogen expected to become the primary gas energy carrier by 2050. While early demand is concentrated in industrial applications, long-term projections suggest that hydrogen may see wider use, including in the production of synthetic fuels.

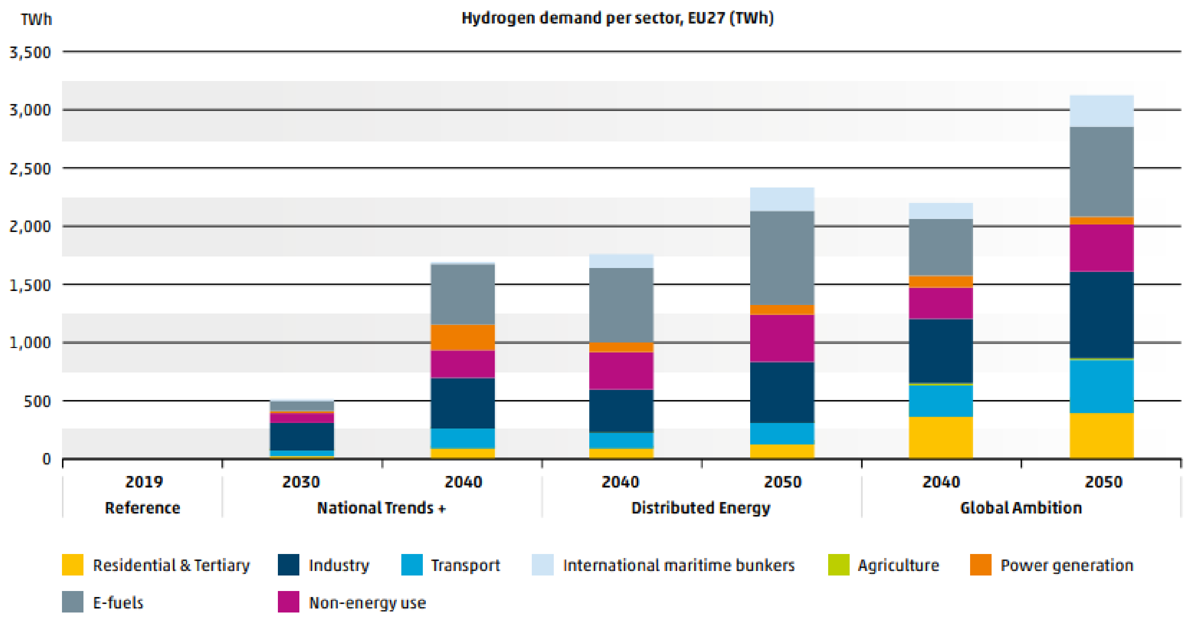

FIGURE 19 : HYDROGEN DEMAND PER SECTOR EU27 (TWH) (SOURCE: ENTSO-E // ENTSOG TYNDP 2024 DRAFT SCENARIOS REPORT – MAY 2024)

Supply

Expanding renewable energy and efficiency measures is expected to decarbonize Europe's energy supply, causing natural gas use to drop sharply after 2030 and end by 2050.

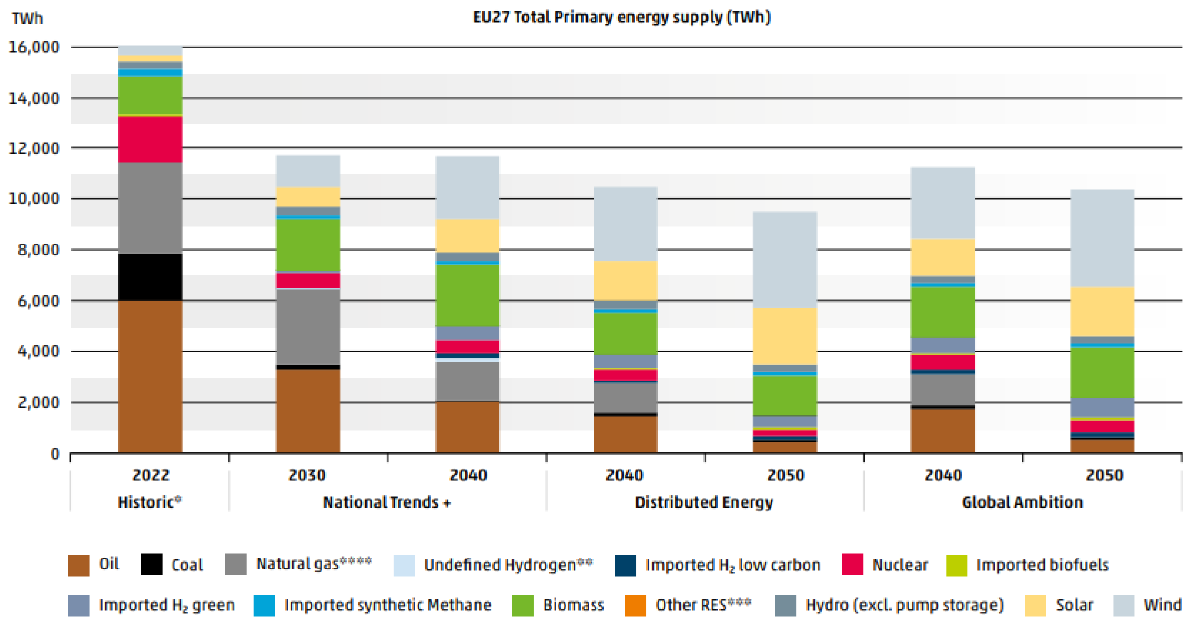

FIGURE 20 : EU27 TOTAL PRIMARY ENERGY SUPPLY IN TWH (INCLUDING INTERNATIONAL MARITIME BUNKERS & INTERNATIONAL AVIATION & NON-ENERGY USE) (SOURCE: ENTSO-E // ENTSOG TYNDP 2024 DRAFT SCENARIOS REPORT – MAY 2024)

All scenarios include a steady decrease in conventional indigenous natural gas production and imports. Biomethane is key to reducing methane emissions, while synthetic methane from electrolysis plays a minor role.

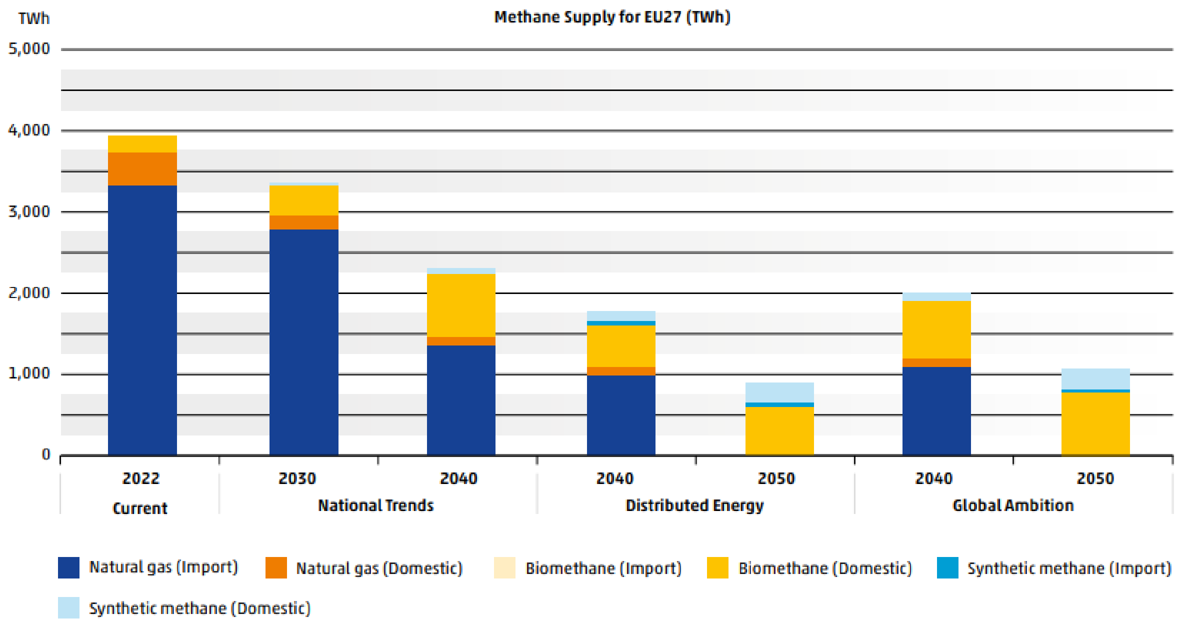

FIGURE 20 : METHANE SUPPLY FOR EU27 (SOURCE: ENTSO-E // ENTSOG TYNDP 2024 DRAFT SCENARIOS REPORT – MAY 2024)

Currently, most of Europe's hydrogen is produced via SMR/ATR, with the rest coming as by-products from other industries. However, this is expected to shift as Europe and the world pursue large-scale hydrogen production through electrolysis powered by renewable energy and develop cross-border hydrogen infrastructure.

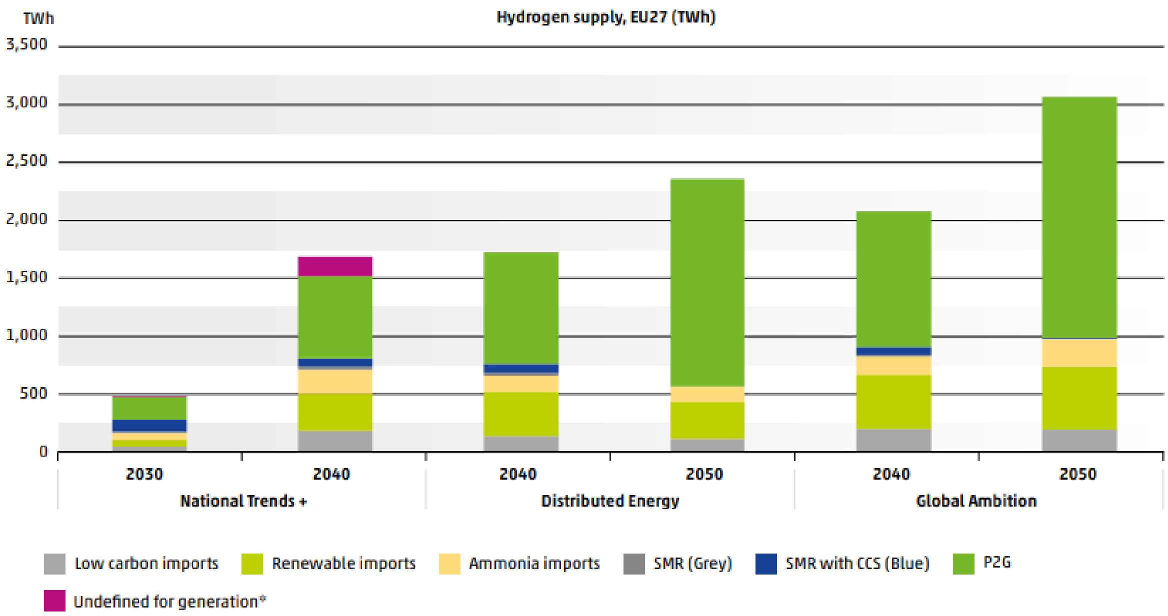

FIGURE 21 : HYDROGEN SUPPLY FOR EU27 (SOURCE: ENTSO-E // ENTSOG TYNDP 2024 DRAFT SCENARIOS REPORT – MAY 2024)

Infrastructure Report

The Infrastructure Report is part of the ENTSOG TYNDP deliverable and presents an overview of potential future gas networks for methane and hydrogen, beginning with the current state. The draft version released in December 2024[12] is informed by comprehensive project data collected between 23 November 2023 and 11 February 2024. Detailed information on individual projects can be found in TYNDP 2024 Annex A – Projects on the ENTSOG website.

A total of 326 projects were included in TYNDP 2024, submitted by over 90 project promoters, including both TSOs and third-party organizations. The projects are categorized into four main groups:

- Hydrogen, which includes transmission (H2T), storage (H2S), reception facilities (H2L), mobility (H2M), and electrolysers (H2E)
- Natural gas, covering transmission (TRA), storage (UGS), and reception, storage, and regasification facilities (LNG)
- Smart gas grids, such as retrofitting for blending (RET), biomethane development (BIO), and synthetic methane (SYN)
- Other types, which include CO2 transport (CO2) and additional infrastructure-related projects (OTH)

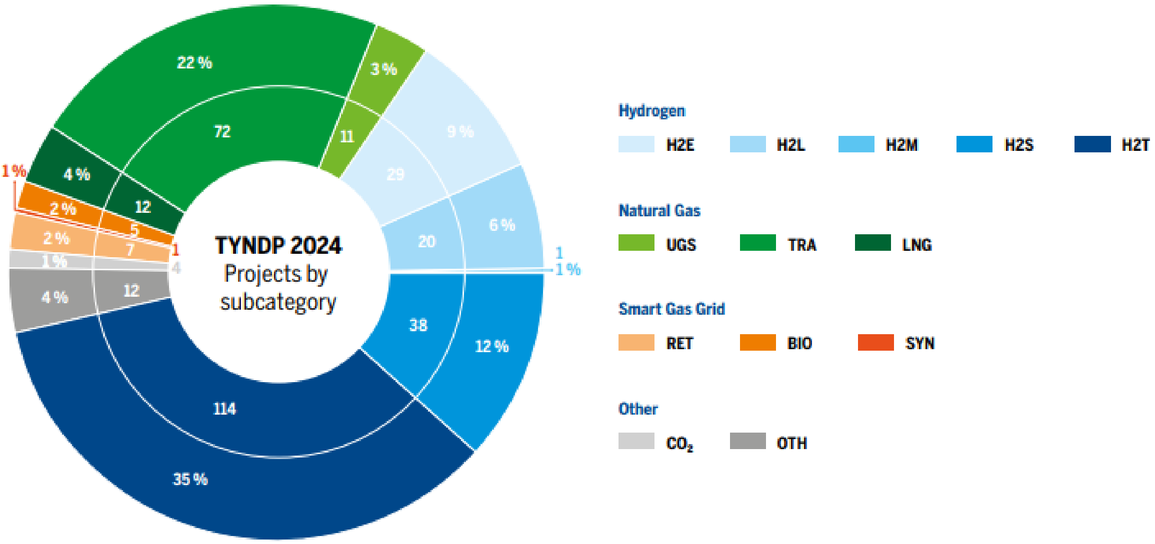

FIGURE 22 : PROJECT INCLUSION IN TYNDP 2024 BY SUBCATEGORY (SOURCE: ENTSOG TYNDP 2024 INFRASTRUCTURE REPORT)

Hydrogen projects account for more than 60% of all submitted projects, with most focusing on hydrogen transport. These projects include new pipes (64), repurposed pipes (14), and combinations of both (36). The timing of these hydrogen projects can be represented based on their maturity status: FID taken, advanced according to pre-defined criteria, and less advanced.

[12] https://www.entsog.eu/sites/default/files/2024-12/TYNDP%202024%20Infrastructure%20report_0.pdf

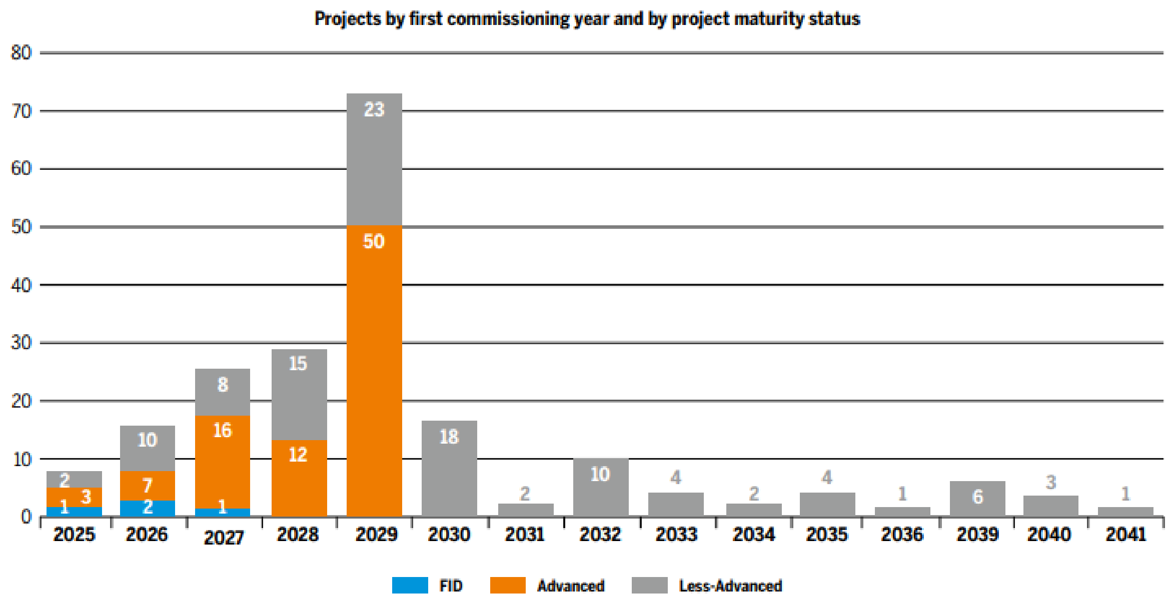

FIGURE 23 : PROJECTS BY COMMISSIONING YEAR AND BY PROJECT MATURITY STATUS – H2T, H2L, H2S, H2E AND H2M (SOURCE: ENTSOG TYNDP 2024 INFRASTRUCTURE REPORT)

The maturity of submitted projects has led to two future infrastructure levels each for hydrogen (PCI/PMI and Advanced) and natural gas (Low and Advanced), which help identify gaps in TYNDP 2024. Interconnection capacities for these levels are detailed in TYNDP 2024 Annex C1 (CH4) and Annex C2 (H2) on the ENTSOG website.

Hydrogen Infrastructure Gaps Identification Report

The TYNDP 2024 Hydrogen Infrastructure Gaps Identification report (IGI report) seeks to identify regional infrastructure gaps within assessed hydrogen infrastructure levels for the first time. The draft version for public consultation was published in December 2024[13].

The analysis of infrastructure gaps covers two hydrogen infrastructure levels for 2030 and 2040, evaluated using the TYNDP 2024 National Trends+ scenario. Three indicators are applied to determine regional hydrogen infrastructure gaps:

- IGI indicator 1: Hydrogen market clearing price spreads
- IGI indicator 2.1: Curtailed hydrogen demand for a reference weather year
- IGI indicator 2.2: Curtailed hydrogen demand for a stressful weather year

These indicator values differ across infrastructure levels (PCI/PMI and Advanced) and years (2030 and 2040). When IGI indicators exceed certain predefined thresholds, this signals an infrastructure bottleneck in the corresponding region. The main purpose of the report is to pinpoint regional infrastructure gaps not addressed by projects contained within the selected infrastructure level. The

[13] https://www.entsog.eu/sites/default/files/2024-12/Draft%20Hydrogen%20Infrastructure%20Gaps%20Identification%20Report_for%20consultation_0_1.pdf

report does not aim to forecast European infrastructure development or future flows, as multiple solutions may address identified issues.

Project-Specific CBA

In the first half of 2025, ENTSOG will conduct a project-specific analysis of TYNDP projects identified as PCI/PMI candidates, utilising a cost-benefit analysis (CBA) methodology as outlined in TYNDP 2024 Annex D1 - Implementation Guidelines. The findings from this analysis will inform the European Commission's establishment of the second PCI/PMI list under the revised TEN-E regulation by the end of 2025.

Fluxys Demand scenarios

Definition

The energy landscape is expected to centre on the energy transition over the coming years. In this context, Fluxys has outlined several potential scenarios for Belgian energy consumption and feedstock that aim for zero emissions by 2050. Multiple sources—including TYNDP ENTSOG/E, national and regional ambitions and targets, historical consumption statistics, internal analyses of projected demand, various international and national reports on energy conversion, and market surveys—were integrated to produce a detailed forecast. As a result, four distinct multi-energy scenarios have been developed (see Figure 24), each defined using different assumptions related to energy intensity and vectors.

This methodology will be updated to comply with the new EU Directive 2024/1788 and EU Regulation 2024/1789.

Demand intensity, which shapes final energy use, depends on factors such as demographic trends, patterns of energy consumption, and anticipated efficiency improvements. Two levels were established to address uncertainties in these areas:

- The "Energy Efficient" scenarios are characterised by a combination of technological progress and changes in energy consumption behaviour, resulting in notable energy efficiency gains across sectors.
- The "Energy Intensive" scenarios reflect a slower rate of technological advancement and behavioural change, leading to comparatively higher final energy demand than in the "Energy Efficient" scenario.

A range of fuels is considered to meet quantified demand:

- In the *electric* scenarios, electrification of final demand is maximised based on commercially available technologies, as well as those with demonstrated experimental effectiveness but not yet fully commercialised.
- In the *molecule* scenarios, although electrification is present, emphasis shifts more towards decarbonised molecules such as hydrogen (in pure form or as a base for e-fuels and derivatives). Methane remains relevant in the

molecule scenario, provided it is carbon-neutral (biomethane, synthetic methane, or natural gas with captured emissions).

Both scenarios also entail a residual transition to other decarbonised fuels, including biomass, biofuels, and derived heat.

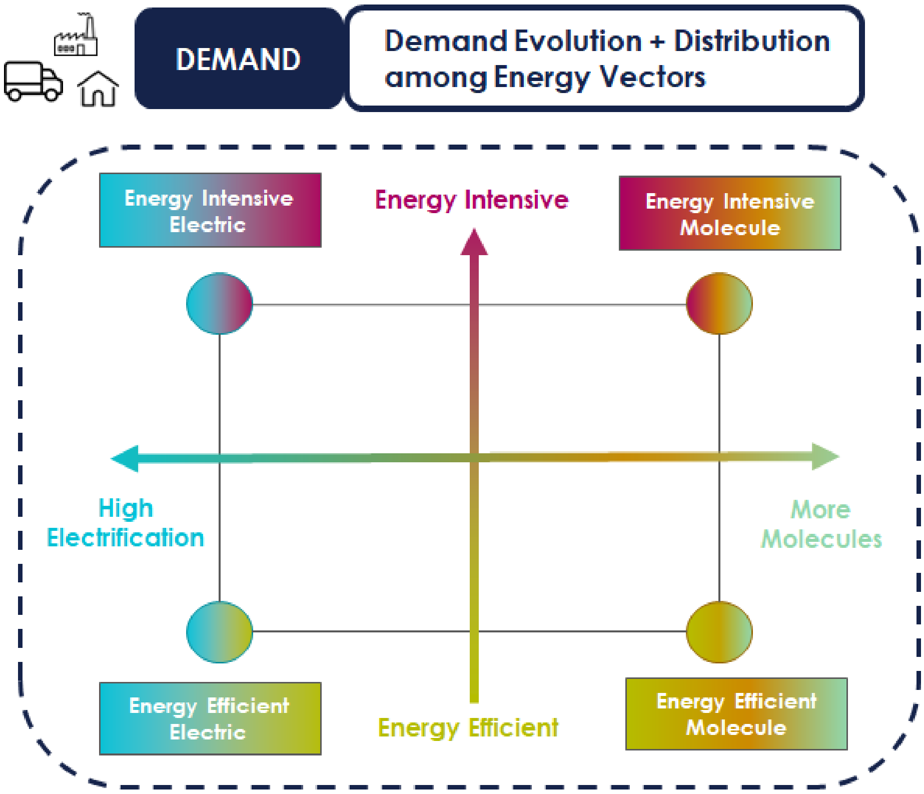

FIGURE 24

While it is uncertain which path will lead to zero emissions by 2050, Fluxys expects all outcomes to fit within four scenario extremes. Over the next decade, differences between these scenarios are likely to be minor.

These scenarios estimate annual demands for methane, hydrogen (and its derivatives), and other energy sources through 2050. Gas-to-power values use Elia's latest power plant adequacy studies.

CCS/CCU projections depend on ongoing fossil fuel use in industry and power generation; in the short term, Fluxys bases assumptions on market participants' input and commitments.

Figure 25 illustrates the expected CH_4 demand (including power plants) for 2025–2034.

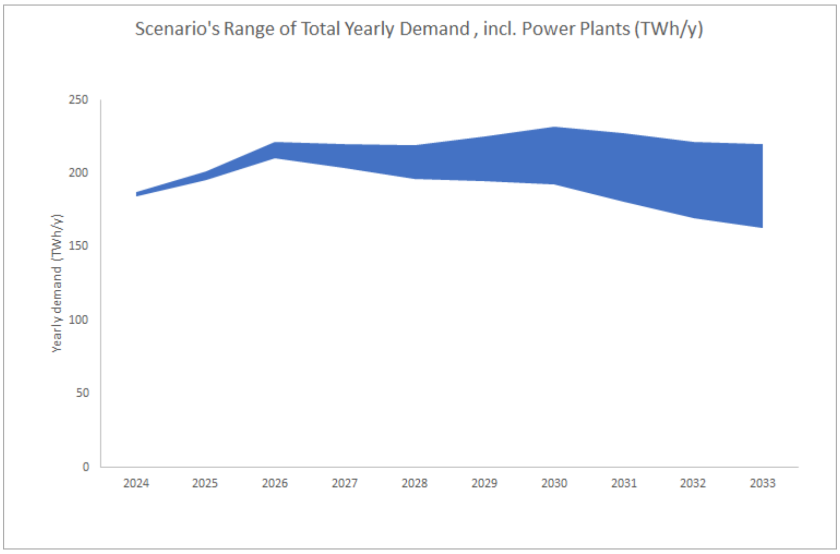

FIGURE 25

Peak values (capacity) for demand and power plants

Grid sizing is based on peak demand rather than annual volumes. These peak values serve as the basis for simulating available transport capacity in molecule networks. Examining network performance during periods of peak capacity demand helps identify whether infrastructure adjustments are required to address demand fluctuations. Due to varied offtake profiles, statistical methods are employed to determine peak values for different market segments.

Distribution Network

METHOD

In addition to customer numbers, boiler efficiency, and building insulation, consumption peaks are also influenced by winter severity and must be analysed with recorded temperatures[14]. Linear regression of past offtakes against ambient temperature is used to estimate peak offtake at -11°C equivalent. The standard winter analysis period runs from November through February.

[14] The concept of 'equivalent temperature' was introduced to consider the thermal inertia of buildings. This temperature is determined as follows: $T_{eq\,D} = 0.6 \times T_{av\,D} + 0.3 \times T_{av\,D-1} + 0.1 \times T_{av\,D-2}$

ASSESSMENT OF WINTER 2023/2024

The winter from November 2023 to February 2024 was relatively mild, with 1,188 degree days compared to a typical 1,400[15]. The coldest day at Uccle was January 10th, reaching -3.9 °C during a one-week cold spell.

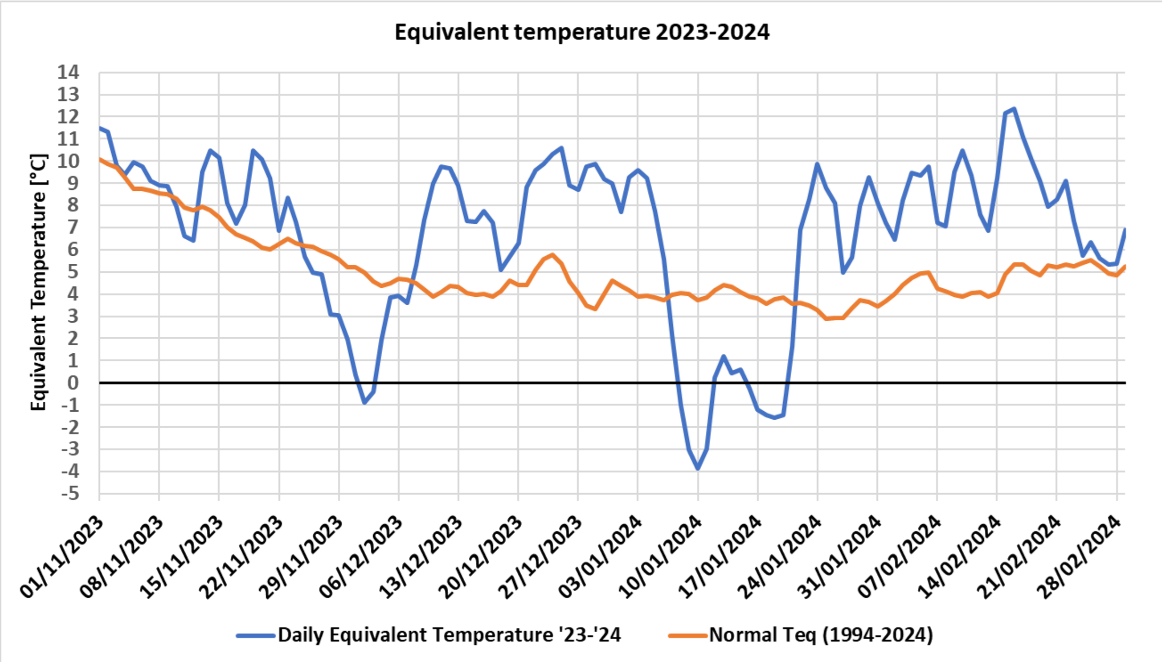

FIGURE 26 : TEMPERATURE PROFILE FOR WINTER 2023/2024

FORECAST

Active connections grew steadily until 2020, but growth slowed and then plateaued from 2021 to 2024 due to new restrictions and alternative heating sources. These factors have contributed to declining demand, reversing previous annual growth trends.

15 1991 to 2020 (winter months), source: Synergrid

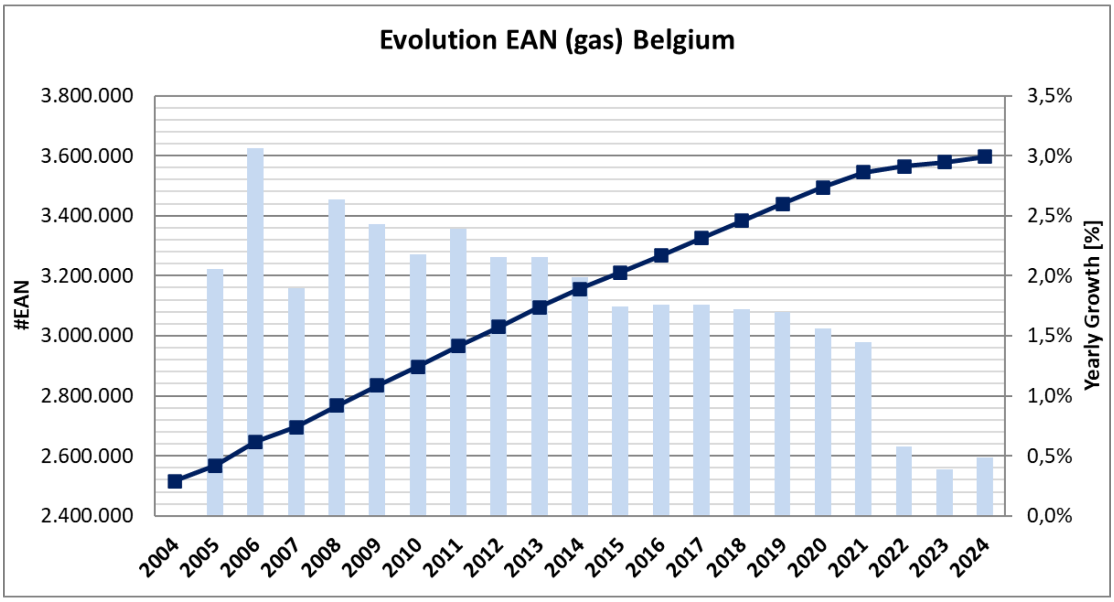

FIGURE 27 : INCREASE IN THE NUMBER OF EAN ACCESS POINTS (SOURCE: SYNERGRID)

Stricter renovation and construction regulations have improved insulation and heating efficiency, while efforts to cut natural gas use have accelerated due to the Ukraine crisis and rising energy prices. As a result, and with fewer new connections, public distribution of natural gas may decline overall, though some local increases are possible. Future peak capacity projections will factor in changes in energy sources, as discussed previously, since technologies like heat pumps differ in consumption patterns from gas boilers.

Power plants, CHP units and industrial customers

METHOD

Currently, temperature has minimal influence on electricity generation[16] and industrial processes. Therefore, the analysis for this market segment relies on historical offtake data alongside a commercial assessment of prospective developments. Since peak demand among industrial customers does not usually occur simultaneously (due to the smoothing effect), absolute peak offtake is adjusted using a regional synchronisation factor for network simulations. For gas-fired power plants, the methodology considers the possible concurrent operation of all generation facilities, which is influenced by factors such as renewable resource availability (solar, wind, hydro), imports and exports, and the technical readiness of the remaining generation units.

[16] This may change in the future with the increase use of heat-pumps for houses heating.

ASSESSMENT OF WINTER 2023/2024

From November 2023 to February 2024, industrial offtake averaged 126 GWh/d, up from 105 GWh/d the previous winter, while power plant peak offtake fell to 213 GWh/d from 250 GWh/d.

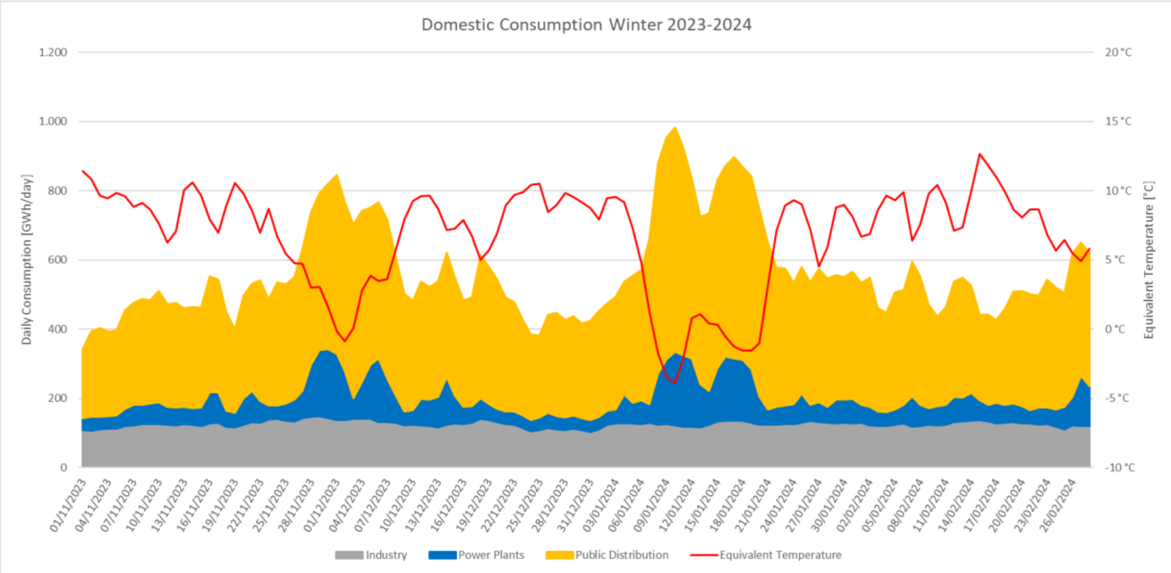

FIGURE 28 : DOMESTIC CONSUMPTION IN WINTER 2023/2024

FORECAST

Industrial Customers

The outlook for industrial energy consumption remains varied. While some industrial clients are reducing or ceasing production activities in Belgium, new industrial projects continue to be initiated annually. For projecting future peak demand values, a similar annual usage profile to historical trends will initially be considered.

Power Generation

Gas-fired power plants play a crucial role in maintaining the balance of the electricity grid. These facilities offer the advantage of rapid start-up times and significantly lower CO_2 emissions compared to coal-fired power stations. Their operational flexibility makes them an ideal backup resource for accommodating variable energy production from wind turbines and solar panels.

The Belgian government has resolved to (partially) decommission the country's nuclear generation assets over the coming years. Consequently, a substantial portion of nuclear capacity—approximately 2 GW—is scheduled to be phased out by 2025. In response, and alongside expanding import capacities and continued growth in wind and solar energy, there will be a need to further develop natural-gas-fired generation infrastructure, including the replacement of existing units that approach the end of their technical or economic lifespan.

Specifically, the government's introduction of the Capacity Renumeration Mechanism (CRM) has led to plans for constructing two additional CCGT (Combined Cycle Gas Turbine) power plants[17], adding a combined capacity of 1.7 GW by 2025. Furthermore, it is expected that older, less efficient plants will continue to operate as peaking units for several years prior to their eventual decommissioning.

Evolution of border capacity

Outlook for exports

In addition to serving the Belgian market[18], the network is utilised for the transmission of natural gas to neighbouring countries.

Transmission to France

In its 'Bilan prévisionnel pluriannuel et Plan décennal de développement 2024-2033' [19](currently under consultation), Natran—the new name for GRTgaz—presents several demand scenarios forecasting a reduction in gas consumption in France between 10% and 30% from 2024 to 2033. A notable decrease is also projected for peak volume requirements.

Since 2022, observed H-gas flows (both average and peak) from Belgium to France have already declined substantially, resulting in France becoming a net exporter to Belgium.

The ongoing process of repurposing pipelines from the methane (CH_4) grid to hydrogen (H_2) or carbon dioxide (CO_2) grids may affect available capacity towards France. One major candidate for repurposing is the DN1000 pipeline between Zomergem and Ville-sur-Haine, which currently transports gas from Zeebrugge's entry zone to the Belgian-French border at Blaregnies. As illustrated in Figure 11, exports to France have significantly decreased since 2022, providing an opportunity to assess the necessity of the existing export capacity at Blaregnies.

Within the framework of the L/H conversion, the volume of L-gas transported by Fluxys Belgium to the French market will progressively decline, ceasing entirely after 2028 and no later than 2030.

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[17] Power plants of Seraing and of Les Awirs.

[18] Luxembourg is considered in the Belgian market as both countries form one single balancing market for natural gas.

[19] https://www.natrangroupe.com/sites/default/files/co/concertation-gaz-pdd-2024-partie-projets-janvier2025.pdf

Transmission to the UK

National Gas's 'Gas Ten Year Statement 2024'[20] outlines four scenarios, all predicting a decline in UK gas demand and domestic production. According to the Gas Winter Review 2025[21], steady supplies come from the UK Continental Shelf (UKCS) and Norway, with flexible sources like LNG, UK storage, and European imports supplementing demand. Currently, the UK's transmission capacity, including the Interconnector, is sufficient to meet market needs and support supply security.

Transmission to Germany

Germany's ongoing Framework 2025[22] outlines three demand scenarios, all anticipating a notable decrease in CH4 consumption, potentially reaching zero by 2045. Conversely, the 'Focus on Security of Supply' scenario projects sustained high demand over the next decade, with an expected increase approaching 2030. This trend may present significant challenges for transmission system operators. As such, it may be prudent to investigate measures to enhance entry points—including at the Belgian-German border—such as expanding entry capacities, LNG terminals, and storage facilities. Additionally, adjustments on the exit side, including cluster strategies for power plants and consideration of simultaneity effects or new capacity products, could also be evaluated.

Given these factors, flows from Belgium to Germany are anticipated to remain robust, despite planned LNG projects within Germany. Investments in the VTN pipeline (Zeebrugge-Eynatten), scheduled for completion by the end of 2026 in Belgium, will secure the necessary exit capacity.

Transmission to the Netherlands

GTS's 2024-2033[23] investment plan outlines three scenarios with declining gas demand. However, domestic production in the Netherlands is being phased out quicker than demand drops, making continued imports—including LNG—essential. Transit into the Netherlands is expected to maintain peak flows at current capacity levels.

Outlook for imports

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[20] https://www.nationalgas.com/sites/default/files/documents/17521_NGT_GTYS_2024_AW07b_INTERACTIVE.pdf

[21] https://www.nationalgas.com/media/publications/gas-winter-outlook

[22] https://ko-nep.de/en/scenario-framework/scenario-framework-2025/

[23] https://www.gasunietransportservices.nl/en/gasmarket/investment-plan/investment-plan-2024

Imports from Norway

Belgium primarily sources its natural gas imports from Norway, which are supplied as a consistent base load. No notable changes in the volume of these deliveries are anticipated in the near future.

LNG imports

Liquefied natural gas (LNG) continues to play a critical role in securing energy supply for European nations. In response to the ongoing conflict in Ukraine, there has been a notable rise in LNG imports—particularly from the United States—with figures reaching 129 TWh in total imports (25 TWh from the US) in 2023, and 91 TWh in total imports (15 TWh from the US) in 2024. These numbers represent a significant increase compared to 2021 levels, which saw 51 TWh in total imports and just 2 TWh from the US. Additionally, the capacity of Fluxys' LNG terminal in Zeebrugge expanded to 30.2 GWh/h in 2024.

Imports from France

Imports from France have been facilitated since late 2015 by the establishment of the Alveringem interconnection point. The imported gas originates either from the Dunkirk LNG terminal or from TRF, the French gas trading hub. In recent years, there has been a clear trend of increasing volumes transported via Alveringem into Belgium. The significance of LNG in Europe's energy supply will continue to be a determinant factor in the ongoing development of this entry point.

Imports from the UK

Imports from the UK via Interconnector fluctuate based on supply and demand, and are shaped by European market dynamics. Recent years saw record interconnector exports to continental Europe, though 2024 figures have dropped. Increased UK gas exports to Europe mainly result from reduced Russian supplies. The Interconnector and BBL pipelines link the UK and EU, supporting Southeast UK supply and LNG transit to Europe. While future usage is uncertain, inter-market balancing remains crucial and peak flows are likely to persist.

Imports from Germany

German volumes are low and likely to stay unchanged in the coming years.

Imports from the Netherlands

L-gas imports will decrease due to the L-to-H conversion. Although Belgium completed this conversion on September 1, 2024, L-gas transmission continues until France finishes its own process. H-gas imports are expected to stay low in the near future as they depend on market factors. Planned hydrogen infrastructure changes in the Netherlands may affect Belgian-Dutch border capacities, potentially reducing entry/exit at Zelzate, creating an exit at Hilvarenbeek, and decreasing entry at S'Gravenvoeren.

Simulation tools

This chapter's simulation method seeks to clarify how methane transport capacity is calculated in Belgium.

Why?

Firm capacity[24] available for sale at the border must be calculated based on the network's ability to support it, considering factors such as minimum contractual pressures at the border or offtakes, client demand, and other relevant constraints. The term "firm" indicates that this capacity must be guaranteed under all possible balanced flow scenarios, meaning the sum of entry flows equals the sum of exit flows (including demand). If no firm capacity is available on a given day, Fluxys may offer lower-priced "interruptible" capacity, which can be curtailed, if necessary, though interruptions are infrequent.

If new pipelines are added to the network, firm capacity can increase; conversely, repurposing pipelines for H2 or CO2 transport reduces the capacity available for CH4. Understanding both scenarios is important for assessing capacity impacts.

Pipeline capacity is generally expressed in GWh/h and depends on factors such as the pressure drop between pipeline entry and exit, gas flow measured in cubic meters per hour, and gas quality (which determines the gross calorific value, GCV). The relationship between flow and pressure drop is nonlinear, requiring advanced simulation tools to calculate available network capacities.

What is the input?

Demand, as previously described, is a primary input. Each client's contract specifies minimum and maximum delivery pressures for methane. Biomethane production serves as an additional network supply.

The network's topology is a second key input; it may change due to investments or repurposing, so multiple scenarios are analysed to assess expansions or reductions.

A third main input is border capacity—both entry and exit—which we aim to align with adjacent TSO capacity.

[24] 'Firm capacity' stands for capacity that can be available, independently of flow patterns in the network.

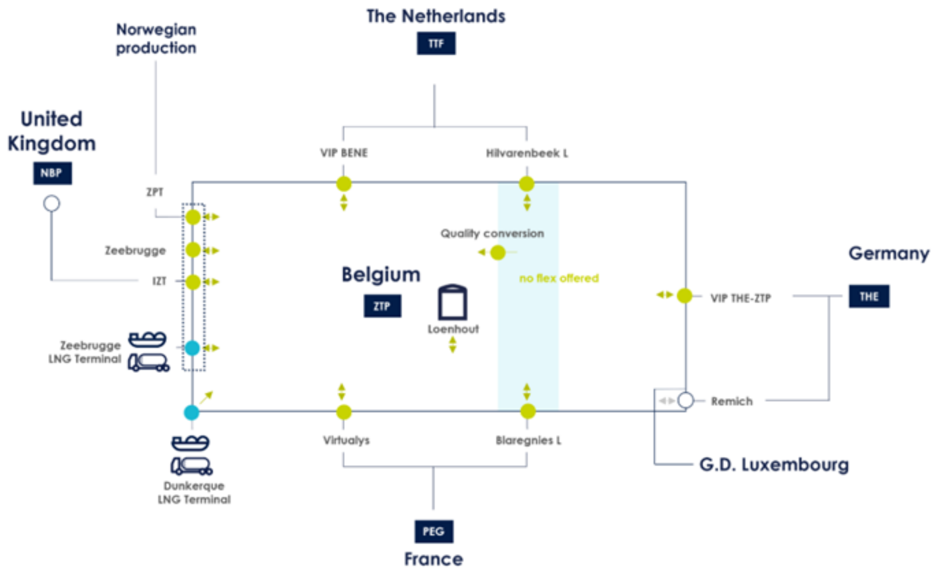

FIGURE 29: COMMERCIAL MODEL FOR THE NATURAL GAS INFRASTRUCTURE

Practically

Building flow patterns

The objective is to determine the capacity that can be ensured under all circumstances; therefore, various flow scenarios are simulated, taking into account Belgian demand on one side and cross-border exit capacities on the other. The analysis of these simulations enables the identification of capacities that can be offered as 'firm' commitments.

To construct the flow scenarios, consumption data are aggregated into clusters representing demand zones supplied in a similar manner. In Belgium, demand is categorised into five zones: Flanders, Antwerp, Limburg, Blaregnies, and ‘s Gravenvoeren. For each zone and client type—industry, CHP (Combined Heat and Power installations), and power plants—a statistical evaluation based on historical flows has been conducted to provide an accurate assessment. For example, minimum and maximum percentages are established for each zone, reflecting realistic usage patterns (as it is improbable that industrial consumption is either zero or at peak levels simultaneously within a single zone). Additionally, a maximum delta in consumption percentage between zones is defined, precluding scenarios where one zone consumes at its maximum while others operate at a minimum.

For public distribution—including residential, tertiary, and small industrial consumers—consumption is determined exclusively as a function of temperature. This temperature-consumption relationship is reviewed and updated annually through the "winter analysis" study.

Check the flow patterns on our network

The second step is to determine if the network can accommodate these flow patterns. All scenarios are tested within the network until the maximum capacity at each border zone—where borders with similar impacts are grouped—is reached. The zone's capacity is then allocated to individual border nodes, within defined technical constraints, to identify the firm available capacity at each border.

Investments need

Change in infrastructure

Investments

With the planned commissioning of new power plants (two units of 850 MW each) by 2025, simulations indicate that the total entry capacity of the H network will continue to meet peak demand, even after full integration of the L-market into the H network.

However, in the scenario of a sustained west-east flow pattern, where entry is primarily from the Zeebrugge zone, reinforcement of the main west-east axis would be required to maintain flexibility[25] and support continued high exports to neighbouring countries. To address this, Fluxys has completed the first phase of reinforcement—a multipurpose[26] DN1000 pipeline of approximately 50 km between Desteldonk and Opwijk[27], which is now operational. A second phase, connecting Zeebrugge (Knokke) to Desteldonk (about 55 km, also DN1000 and suitable for hydrogen), has been approved. This phase is expected to be completed by 2026, enabling a fully redundant pipeline route between Zeebrugge and the German border at Eynatten. One of these routes may be allocated for hydrogen transport, depending on market developments.

For public distribution supply, network capacity utilization is monitored collaboratively with distribution system operators (DSOs) through detailed analyses and simulations. Given the anticipated decline in natural gas consumption by residential and tertiary sectors, investments to accommodate local or regional growth are expected to be limited, though not entirely ruled out.

For new industrial clients or power plants, existing networks typically have sufficient capacity to support additional connections. Nevertheless, if large-scale projects coincide with the construction of new industrial facilities or power plants, localized investments might be necessary.

Repurposing

Fluxys is considering repurposing parts of its existing CH4 network for H2 and CO2 transport, given decreasing CH4 use domestically and for export. This would allow

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[25] To cope with intraday demand fluctuation

[26] A multipurpose pipeline is a pipeline that can be used to transport either methane, hydrogen or carbon dioxide.

[27] This pipeline is fit for hydrogen

cost-effective reuse of existing infrastructure instead of building entirely new pipelines. A 'repurposing exercise' is underway to assess impacts on natural gas capacity, including potential reductions in entry and transit capacity, the latter in collaboration with neighbouring TSOs. Initial analysis focuses on repurposing duplicated pipelines to maintain some gas transport capability. The evaluation is ongoing.

Investment, repurposing and decommissioning program

Investment program

Summary

Fluxys Belgium and Fluxys LNG plan investments totalling **€1,506 million over the period 2025-2034.**

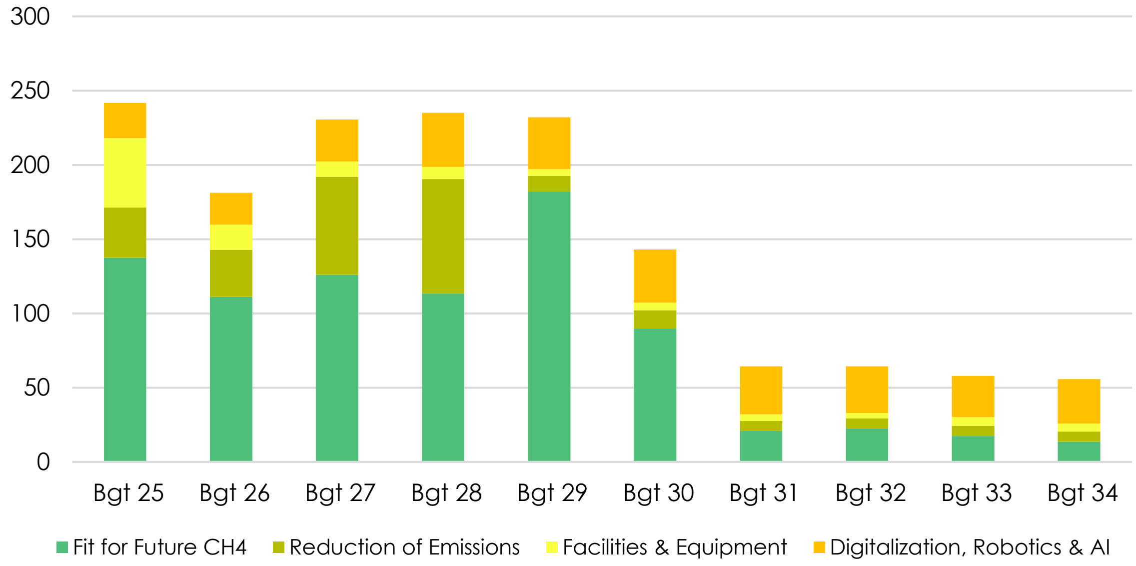

FIGURE 30 : 2025-2034 INVESTMENT PLAN BY AREA

Investments will be made in the following areas:

- **Fit for the future:** €835 million
- **Reduction of emissions:** €258 million
- **Facilities & Equipment:** €111 million
- **Digital, Robotics & AI:** €302 million

Thanks to the investments made in recent years, the Belgian gas transmission network is sufficiently dimensioned, has significant entry capacity (>10 mcm(n)/h), is bidirectional, and well-integrated with other gas transmission systems in North-West Europe.

Approved projects account for €162 million, or 11% of the total amount. These are projects scheduled to be rolled out in the near future (2024-2026). For most of the allocated amounts (€1,152 million), the projects have been identified but no decision has been made yet. In addition, an amount of €160 million has been earmarked for needs not precisely defined yet.

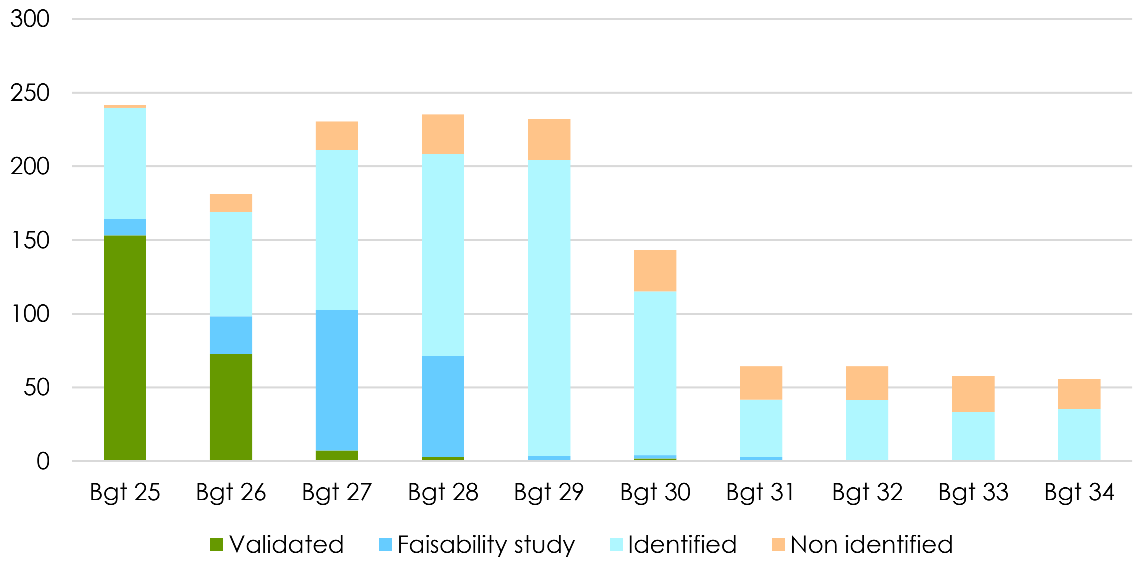

FIGURE 31 : 2025-2034 INVESTMENT PLAN MATURITY LEVEL

The total value of the investment plan is not significantly higher than the previous version of the plan (€32 million more than for the period 2024-2033).

The amounts shown are indicative and may change depending on whether the projects in question are given the final go-ahead or on changes to the planned technical solutions or market conditions.

Fit for the Future

Earmarked amount: **€835 million**

This investment category focuses on the adaptation and enhancement of infrastructure to maintain network and facility integrity, including the LNG Terminal in Zeebrugge and the storage facility in Loenhout. The scope covers the renewal of valves and equipment, pipeline rerouting, new customer connections, and pipeline restructuring.

Planned investments include:

- Infrastructure upgrades to support green gas injection at over 15 projects.
- Construction of a new jetty at the Zeebrugge Terminal to improve supply security (pending final investment decision).
- Strengthening of the backbone network:
- Development of the Knokke-Evergem pipeline.
- Development of the Glabbeek-Halen pipeline (subject to future CRM requirements).

Reduction of emissions

Earmarked amount: **€258 million**

This investment category includes all scheduled projects aimed at lowering the environmental impact of Fluxys Belgium and Fluxys LNG operations, particularly their carbon footprint. This encompasses initiatives to further decrease emissions at the LNG Terminal in Zeebrugge and the storage facility in Loenhout.

Planned investments include:

- Installation of new Open Rack Vaporizers (ORVs) at the Zeebrugge Terminal (pending final investment decision)
- Implementation of solar panels and heat pumps
- Ongoing methane emissions reduction program
- Reduction of methane emissions from compressors at the underground storage site in Loenhout.

Facility & Equipment

Earmarked amount: **€111 million**

This amount covers necessary investments in buildings and equipment, including:

- Leak detection tools, patrol vehicles, welding tools, furniture, etc.
- Head office renovation.
- New Intervention Center building.
- Other buildings such as the LNG terminal and regional offices.

Digital, Robotics and AI

Earmarked amount: **€302 million**

This amount includes investments aimed at developing new applications for managing and marketing gas flows, enhancing digitalisation, and addressing the obsolescence of existing systems, which constitutes a significant portion of the budget.

Planned investments include:

- Preparation of Gas Flow and Commercial Systems for future requirements: address system obsolescence, incorporate market developments, adapt to technological changes, and maintain cybersecurity.
- Maintenance of other software systems, such as engineering, procurement, SAP migration, and field applications.
- Digital infrastructure: update equipment based on lifecycle, establish a cloud environment, gradually renew optical fibres, and maintain telemetry and telecommunication systems.
- Robotics and AI: conduct proof-of-concept initiatives and small-scale projects.
- Ongoing digitalization: improve operational efficiency in various areas over the long term through digital transformation.

Repurposing and decommissioning program

To date, the potential for repurposing has been evaluated individually for each case. Reviews have been conducted on sections of the current natural gas network based on market demands for hydrogen or carbon dioxide infrastructure. At present, two possible candidates have been identified:

- A DN1000 pipeline between Zomergem and Ville-Sur-Haine.
- A DN600 pipeline between Zomergem and Zelzate.

It should be noted that the repurposing of the pipeline between Zomergem and Ville-Sur-Haine could result in a significant reduction in transportation capacity to France at the Blaregnies interconnection point. Any such changes would require agreement with French counterparts.

Additionally, the repurposing of natural gas assets must not compromise security of supply (a.m. candidates do not result in a security of supply issue for Belgium); for instance, decreasing gas volumes alone is not a sufficient criterion, as peak supply capacity must still be maintained. Hence, repurposing decisions will involve consultation with relevant stakeholders, such as competent authorities.

Within this network development plan, no assets have yet been identified for decommissioning. However, the completion of the L to H migration in France by 2028 may permit the reassessment of certain assets currently used for L-gas transportation.

A more systematic method for identifying candidates for either repurposing or decommissioning is under development. The intention is to integrate this methodology with the forthcoming mandatory "scenarios" approach.

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