THE ROLE OF RENEWABLE LIQUID GASES IN EUROPE'S ENERGY TRANSITION – PATHWAYS, BENEFITS, AND POLICY PRIORITIES FOR SCALING UP

A White Paper commissioned by DCC Energy and SHV Energy

27 MARCH 2026

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Contents

Independence of analysis

DCC and SHV's role in commissioning this independent report has been strictly limited to providing financial support for its preparation. Neither party has supplied any data, analysis, or input into the report's methodology, findings, or conclusions. Frontier Economics has operated with editorial independence throughout, applying their own judgement, methodology and sources without direction or influence from either commissioning party.

Executive Summary

Europe's energy transition is entering a delivery phase. While electrification and network-based gases, notably hydrogen, will remain central to long-term decarbonisation strategies, their deployment in rural and off-gas-grid segments faces structural constraints. Limited grid capacity, hydrogen infrastructure timing, high upfront investment requirements and winter peak demand pressures can slow or complicate decarbonisation in these areas. In many such settings, the near-term counterfactual to low-carbon solutions is not rapid electrification, but continued fossil fuel use. The aggregate impact of this can be material: estimates suggest that around 20–30% of the EU's total greenhouse gas emissions originate in predominantly rural areas.

Renewable liquid gases (rLG) – including renewable LPG (rLPG) and renewable dimethyl ether (rDME) – offer a complementary pathway in these off-gas-grid and hard-to-electrify settings. By building on the existing liquid gas value chain and end-use infrastructure, rLG can enable gradual emissions reductions without requiring immediate structural change at the point of use. Their role is not to replace electrification or hydrogen as core transition pillars, but to complement them where infrastructure constraints, capital intensity or technical feasibility limit immediate alternatives.

This White Paper assesses the economic viability, system implications and climate impact of rLG across the EU-27, the United Kingdom, Norway and Switzerland, focusing on residential heating and selected industrial process-heat applications.

Market outlook: Liquid gases remain structurally relevant in rural and off-gas-grid segments, even as overall demand declines. Under stylised electrification and efficiency assumptions, residual liquid gas demand for energy purposes could decline by at least 30% by 2040. Supply projections suggest potential European rLG production of 2.3–7.5 Mt by 2040, implying that up to 70–80% of projected LPG demand for energy purposes could be met with rLG in 2040. Deployment will therefore depend on enabling investment conditions.

End-use economics: Using a total cost of ownership framework, we assess rLG-based solutions against electrification in representative single-family houses in Germany, Poland and Italy, reflecting rural and off-gas-grid building types with radiator-based heat distribution. In these cases, rLG-based boilers are broadly cost-competitive with air-source heat pumps, particularly where heat pumps require high upfront investment or building retrofit. For industry, we examine brick firing, asphalt production, aluminium melting and distilleries. rLG performs most strongly in medium- to high-temperature processes such as brick firing, asphalt production and aluminium melting, where electrification requires significant capital expenditure and plant modification while delivering limited efficiency gains. In low-temperature applications such as distilleries, where heat pumps achieve strong efficiency improvements, electrification typically remains the lower-cost option.

System implications: Full electrification of current LPG demand would increase annual electricity demand by around 4.1% and raise winter peak demand by an estimated 4.4%. Maintaining system adequacy under this higher peak would require additional firm capacity. Depending on the technology mix, indicative capital expenditure ranges from approximately EUR 11–14 billion if met primarily with open-cycle gas turbines, to EUR 16–20 billion under a balanced gas portfolio, and up to EUR 46–56 billion if delivered through a diversified low-carbon firm capacity mix. These figures reflect differences in technology choice rather than modelling uncertainty. In addition, higher peak loads could trigger further distribution grid reinforcement. In selected constrained locations, rLG can reduce pressure on peak electricity demand and associated grid upgrades by limiting additional electrified load. While the magnitude of this effect is location-specific, it is relevant where infrastructure expansion is delivery-constrained.

Climate impact: Under conservative carbon intensity assumptions (24 gCO_2e/MJ), rLG deployment could deliver material cumulative emissions reductions to 2040. Under a moderate supply trajectory, cumulative emissions savings of fossil LPG displacement could reach around 76 $MtCO_2e$ to 2040. Savings can be substantially higher if rLG is displacing higher-carbon fuels such as heating oil. At household level, gradual heat pump uptake alone (30% switching by 2040) reduces cumulative emissions by around 14% of cumulative CO_2 emissions over 2025–2040 relative to continued fossil LPG use. Combining heat pump deployment with gradual rLG blending increases cumulative savings to an additional 28%, assuming a central LPG-rLG blend. The climate value of rLG therefore depends both on available supply volumes and on prioritised deployment in segments where the near-term counterfactual is continued fossil fuel use.

Policy implications: Policy should enable rLG where they are a cost-effective complement to electrification and network-based gases. Priorities include coherent and investable price signals across the policy framework (in particular EU ETS 1 and EU ETS 2, energy taxation and levies), consistent regulatory recognition across relevant frameworks, and an outcome-based level playing field across decarbonisation options. Where complementary demand-side instruments are considered alongside carbon pricing, these should be technology-neutral and recognise comparable emissions outcomes across energy carriers, ensuring that renewable liquid gases can participate on equal terms. Policy assessments should also incorporate a stronger system-cost perspective, including implications for peak demand, firm capacity and grid reinforcement when deploying rLG as an alternative to electrification. Finally, streamlined certification and traceability frameworks can help reduce transaction costs and enable scalable cross-border value chains.

1 Context: The role of rLG in rural & off-gas-grid decarbonisation

Europe's energy transition is entering a critical phase. Achieving the EU's climate ambitions – reducing greenhouse gas emissions by at least 55% by 2030, around 90% by 2040, and reaching climate neutrality by 2050[1] – will require deep emission reductions across all parts of the energy system. While much policy attention has focused on large industrial emitters and the power sector, meeting these targets will also require addressing emissions from areas that have so far remained at the margins of decarbonisation efforts. This includes the wide range of off-gas-grid energy uses across Europe's rural households, commercial sites, and industrial facilities.

141m
rural residents in the EU27, UK, NO, and CH

A significant share of Europe's population and economic activity is located in rural or non-urban areas with limited access to the grid-based energy carriers such as natural gas. Around 30% of EU citizens (approximately 137 million people) live in predominantly rural areas, with an additional 4 million rural residents in the United Kingdom, Norway, and Switzerland.[2]

In these rural and often off-gas-grid settings, energy demand is still often met with fossil fuels such as heating oil and liquefied petroleum gas (LPG) – particularly for space heating in older buildings and for process energy in agriculture and small-scale industry. While individual consumption is typically modest, the aggregate impact is material: estimates suggest that around 20–30% of the EU's total greenhouse gas emissions originate in predominantly rural areas.[3] Decarbonising rural and off-gas-grid energy use is therefore an important – and often under-addressed – part of delivering climate targets.

20–30 %
of EU GHG emissions from rural areas

Decarbonising energy consumption in these segments presents a substantial challenge. Electrification and the use of low-carbon molecules, in particular green and blue hydrogen, are expected to be the main long-term decarbonisation routes. However, despite their central role in long-term decarbonisation strategies, both approaches face notable constraints in off-gas-grid rural areas.

Hydrogen supply is likely to remain scarce and hydrogen networks are unlikely to reach many locations soon. Electrification is often constrained by local grid capacities and typically requires

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1 Regulation (EU) 2021/1119

2 EU-27 data: The EU rural vision. UK, Norway, Switzerland: 2016 Eurostat data, extrapolated using EU-27 rural population growth rates.; for Norway, UK, CH we use data from 2016 and adjust by the same change rate as EU27

3 SIMPSON, C. and RODRIGUES, F., JRC Highlights Report 2024 - From Science to Impact, BONJEAN, I., BRAY, J., ČELIKOVIĆ, I., FORNARA, M., JAMES, K. et al. (editors), Publications Office of the European Union, Luxembourg, 2025, https://data.europa.eu/doi/10.2760/6280845, JRC141578.

substantial upfront investments in building retrofits and electricity network reinforcement. In addition, electrified heating technologies are not equally efficient across all temperature ranges, particularly for applications requiring high-temperature heat. During periods of low renewable generation combined with high heating demand, such as cold winter spells, increased electrification would also raise peak electricity loads, potentially requiring additional investment in firm backup capacity, including gas-fired power plants.

21m **rural residents are over the age of 65.**

As a result, decarbonisation in rural and off-gas-grid areas via hydrogen or electrification is particularly capital-intensive. These high upfront investment requirements pose a significant challenge for rural households, where demographic trends further exacerbate affordability concerns: more than 21 million people living in rural areas across the EU are over the age of 65, a group for whom large capital investments are often difficult to finance.

1.1 Renewable liquid gases as a complementary solution

LPG plays a structurally important role in rural and off-gas-grid energy supply, providing a reliable, storable fuel for space heating and selected process-heat applications where network-based alternatives are not available. Stored as a liquid under moderate pressure, it enables flexible distribution beyond the reach of pipeline infrastructure and remains embedded in existing storage, distribution and appliance systems across Europe.

Renewable liquid gases (rLG) build on this structural role. As low-carbon alternatives to conventional LPG, they can, in many applications, use the same infrastructure and end-use equipment, enabling gradual decarbonisation without requiring immediate structural change. This makes them particularly relevant in rural and off-gas-grid settings, where electrification or hydrogen deployment may be delayed, technically challenging or associated with high upfront investment.

1.2 Scope and approach of this White Paper

This White Paper assesses the role of renewable liquid gases as a complementary decarbonisation option across the EU-27, the United Kingdom, Norway and Switzerland. The analysis focuses on domestic and commercial space heating as well as selected industrial process-heat applications.

The White Paper is structured as follows:

- In **Chapter 2 (Foundation)**, we introduce renewable liquid gases in greater detail, including their applications, characteristics and production pathways, and situate them within the existing liquid gas value chain.
- In **Chapter 3 (Outlook)**, we assess projected demand and supply for renewable liquid gases in Europe to 2040 and examine the implied alignment between residual demand and available supply under different scenarios.

- In **Chapter 4 (Economic viability)**, we evaluate the end-use economics of renewable liquid gases in residential and selected industrial applications, benchmarking them against electrification options using a total cost of ownership framework.
- In **Chapter 5 (System perspective)**, we analyse electricity system implications of large-scale electrification and assess the complementary role of renewable liquid gases in addressing peak demand, firm capacity requirements and grid constraints.
- In **Chapter 6 (Climate perspective)**, we estimate the potential emissions impact of renewable liquid gases under constrained infrastructure conditions, focusing on cumulative reductions to 2040.
- In **Chapter 7 (Conclusions)**, we synthesise the economic, system and climate findings and assess the overall value of renewable liquid gases in rural and off-gas-grid decarbonisation.
- In **Chapter 8 (Policy implications)**, we identify key regulatory barriers and outline targeted policy actions to enable renewable liquid gases where they deliver economic, system and climate value.

The analysis does not constitute a full energy system optimisation model or a forecast of technology shares. Rather, it aims to clarify where rLG can add economic and system value within the 2025–2040 timeframe. Detailed assumptions, methodological explanations and calculation parameters underlying the quantitative analysis are provided in the Technical Annex.

2 Foundation: rLG – Application, characteristics & pathways

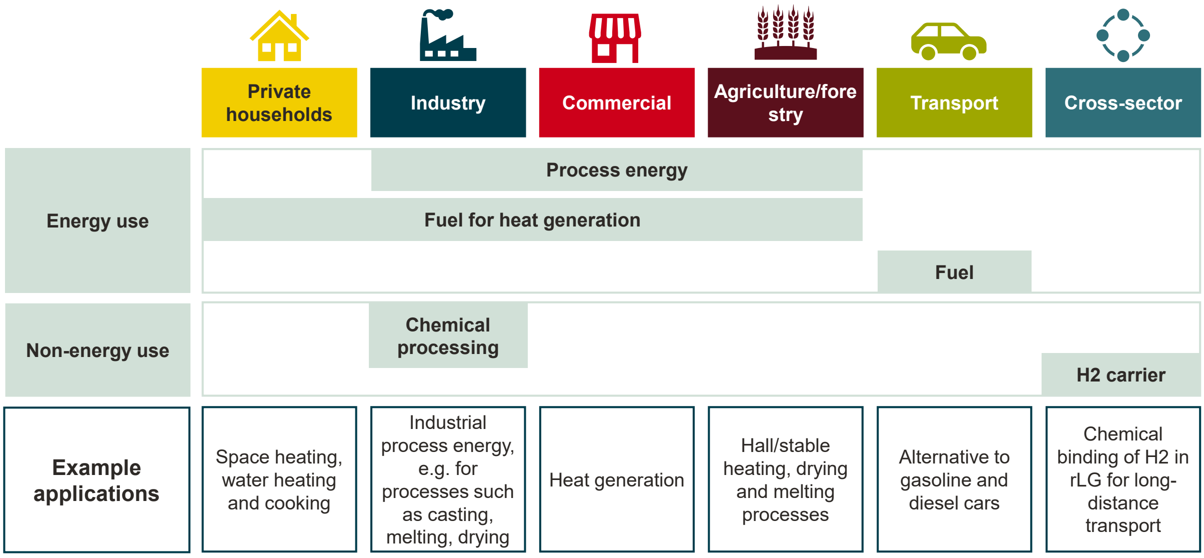
Liquid gases play an important role in rural and off-gas-grid energy systems across Europe. As storable fuels that can be transported and distributed independently of pipeline infrastructure, they provide a flexible energy carrier for space heating, hot water and selected process-heat applications in locations where network-based alternatives are not available.

Today, the dominant liquid gas in these applications is fossil LPG, which is primarily composed of propane and butane and stored as a liquid under moderate pressure. LPG enables reliable distribution beyond the reach of natural gas networks and remains embedded in existing storage, distribution and appliance systems across Europe. Understanding where and how conventional LPG is used today provides the baseline for assessing decarbonisation options within the liquid gas value chain.

LPG is used across a wide range of end uses, including heat generation and process energy (see Figure 1). In households, LPG is mainly used for space heating, hot water and cooking in off-gas-grid settings. In commercial and industrial applications, it supports diverse process-heat needs – for example in drying, melting, casting and cooking – with around 700,000 businesses across industry and manufacturing relying on LPG for heating and process heat, often at smaller sites that are not well served by network infrastructure. [4] In agriculture and forestry, typical uses include heating of buildings and drying processes. Beyond these heat-related uses, LPG is also used in transport and as a feedstock in non-energy applications.

[4] Liquid Gas Europe (2025), *Outlook* for rLG in Europe, March 2025. Available here. Accessed: March 2026.

Figure 1 Applications of LPG



Source: Frontier Economics

In 2024, total LPG demand in the EU-27 plus the United Kingdom, Switzerland and Norway amounted to approximately 29.9 million tonnes.[5] Of this, around 16.5 million tonnes were used for energy purposes. This corresponds to an energy use of roughly 213 TWh, equivalent to about 1.7% of the EU-27+UK+NO+CH's final energy demand.[6]

2.1 The Role of rLG in a Diversified Decarbonisation Strategy

While LPG represents a relatively small share of overall energy demand, it remains structurally relevant in rural and off-gas-grid segments where alternatives such as electricity or pipeline gas are unavailable, delayed, or costly to deploy. This makes the liquid gas value chain a practical starting point for decarbonisation in these segments.

Renewable liquid gases (rLG) build on this starting point by providing low-carbon supply options within the same value chain. As drop-in fuels compatible with existing infrastructure, rLG can be deployed without major system changes.[7] This makes them particularly suitable for rural areas where structural barriers delay the rollout of electricity- or hydrogen-based systems. In these settings, rLG can not only contribute to long-term emission reductions but

5 Argus Media (2025): Statistical Review of Global LPG 2025. Available here. Accessed: March 2026.

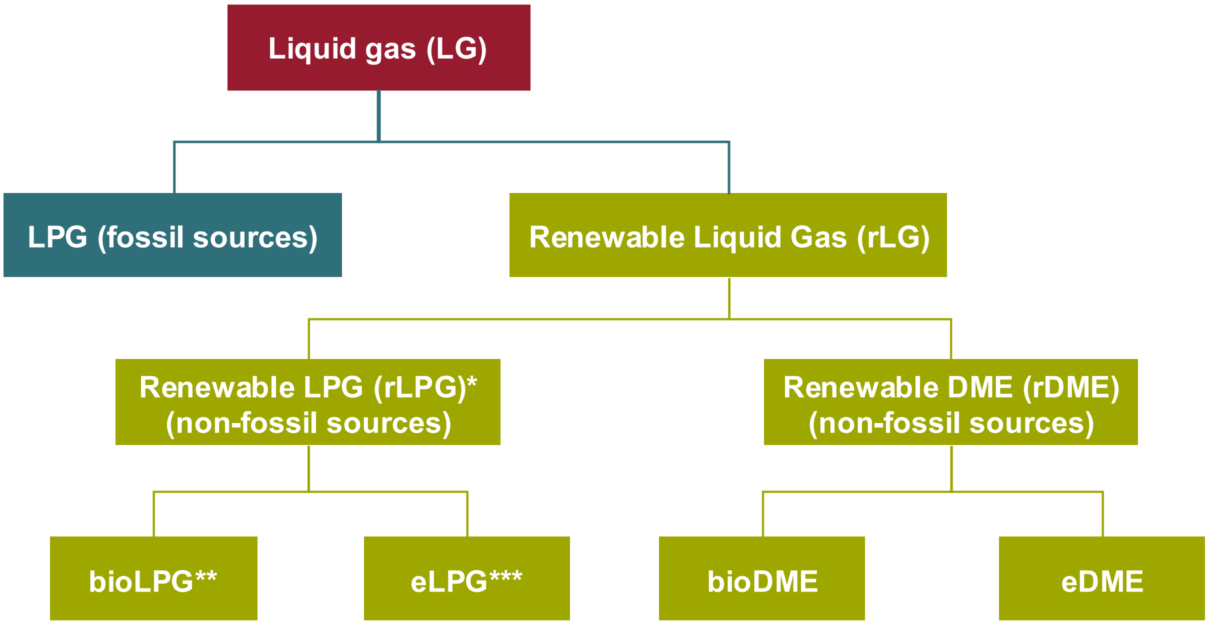
6 Eurostat, Sustainable Development Goal Indicator 7.10: Primary Energy Consumption, European Commission. Available here; Department for Energy Security and Net Zero (DESNZ), Energy Consumption in the UK (ECUK) 2025, United Kingdom Government, 2025. Available here; Swiss Federal Office of Energy (SFOE), Overall Energy Statistics (Gesamtenergiestatistik), Federal Department of the Environment, Transport, Energy and Communications (DETEC). Available here. Accessed: March 2026.

7 Where DME is used (e.g., in blends), equipment compatibility can depend on blend levels and local technical standards.

also act as a bridging solution – helping to close decarbonisation gaps until electricity and hydrogen infrastructure is sufficiently developed.

Figure 2 illustrates the classification of liquid gases, distinguishing between conventional LPG from fossil sources and rLG from non-fossil sources. rLG includes two main categories: renewable LPG (rLPG), which itself comprises biogenic variants such as bioLPG and synthetic versions like eLPG, and renewable DME (rDME).

Figure 2 Overview of Liquid Gas and Renewable Alternatives



Source: Frontier Economics based on Liquid Gas Europe (2025), Outlook for rLG in Europe, March 2025. Available [here](). Accessed: March 2026.

*Note: * may also be referred to as renewable propane or renewable butane; ** may also be referred to as biopropane or biobutane; *** may also be referred to as ePropane or eButane*

Beyond their classification, rLG offer a range of functional advantages that support their role in a diversified decarbonisation strategy. These include favourable emissions characteristics, broad applicability, compatibility with existing infrastructure, and decentralised availability. In addition, their established technology base and relatively low integration costs make them a pragmatic option, particularly in areas where alternative low-carbon solutions face structural barriers. An overview of the main benefits of rLG is provided in Table 1.

Table 1 Benefits of rLG

	Aspect	Benefit
	Renewable Origin	rLG can be produced from a range of renewable sources, including biomass, waste materials, or via synthetic processes using green hydrogen and captured CO_2.

Aspect	Benefit
Versatile Applications	rLG can be used across various sectors and technologies, including residential heating, industrial process heat, and off-gas-grid energy supply (see Figure 1).
Infrastructure Compatibility	rLG shares similar physical and chemical properties with conventional LPG and can be used with existing infrastructure and appliances with minimal or no technical adjustments.
Accessibility	rLG can be distributed and used even in remote or rural areas not connected to public energy networks, making it suitable for decentralised energy supply.
Cost Efficiency	rLG is compatible with existing gas heating systems, enabling low-carbon heat supply without major upfront investment.
Clean Combustion	rLG burns more cleanly with lower soot formation, lower sulphur content and reduced NOx emissions compared to other fuels.
Established Technology	The underlying appliance and distribution technologies are mature and widespread – millions of LPG-compatible systems are already in place across Europe, requiring minimal adaptation and training compared to other technologies such as heat pumps.

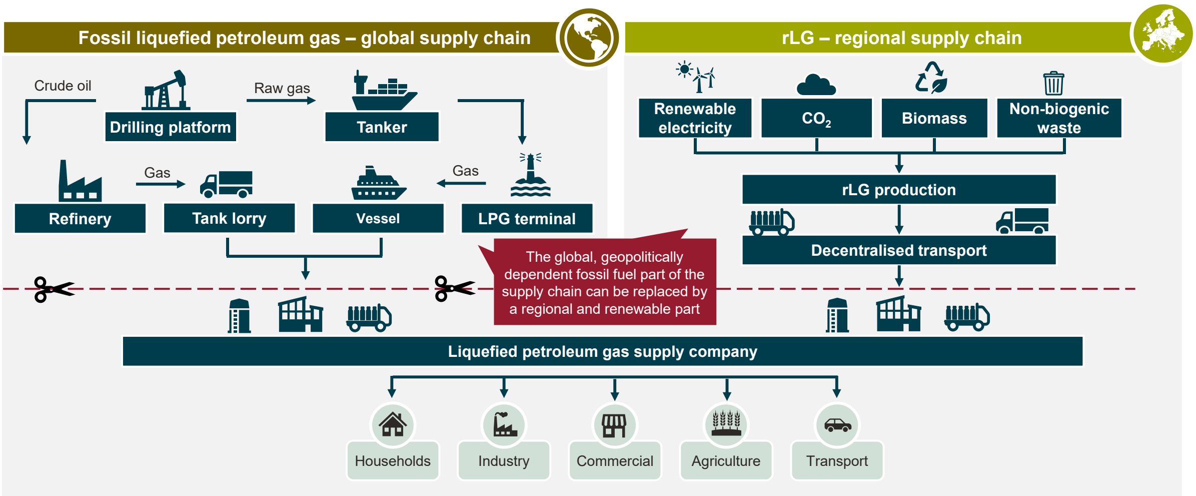
Source: Frontier Economics

2.2 Supply Chain Resilience Through Regional rLG Production

Beyond their technical and economic characteristics, rLG also offer strategic advantages in terms of supply security. Unlike fossil LPG, which relies on globally integrated value chains and imports of crude oil or gas, rLG – particularly when produced from regional biomass, waste, or renewable electricity – can be generated locally. This reduces dependence on politically sensitive global supply chains and supports greater resilience in times of geopolitical disruption.

Figure 3 contrasts the global supply chain for fossil LPG with the more decentralised and regionally anchored supply chain of rLG, highlighting the potential contribution of rLG to a more secure and autonomous energy system.

Figure 3 Comparison of the supply chains for LPG (global) and rLG (regional)



Source: Frontier Economics

2.3 rLG production pathways and feedstocks

There is a wide range of technical pathways to produce rLG, spanning alcohol-to-fuel routes, upgrading of biogenic gases, lipid-to-fuels processes, gasification-based pathways and CO_2- and hydrogen-based electro-routes. A comprehensive overview of these options, their associated products and feedstocks is provided by Liquid Gas Europe, drawing on work by NFCC and Frazer Nash. Table 2 summarises these pathways for reference.

Table 2 rLG production pathways and feedstocks

Pathway	Product or co-product	Feedstock
Alcohol-to-Fuel (LPG)	bioLPG	Ethanol
Biogas (LPG)	bioLPG	Biogas
Biogas (DME)	bioDME	Biogas
CO_2 and H_2 to fuel (DME)	eDME	CO_2, H_2
CO_2 and H_2 to fuel (LPG)	eLPG	CO_2, H_2
Gasification with FT (LPG)	bioLPG	MSW, Waste wood and residues
Gasification (DME)	bioDME	MSW, Waste wood and residues
HVO & HEFA (LPG)	bioLPG	Tallow, UCO, Virgin Oils

Pathway	Product or co-product	Feedstock
Pyrolysis (LPG)	bioLPG	MSW, Waste wood and residues, Waste tyres

Source: Liquid Gas Europe based on NFCC and Frazer Nash

2.4 rLG with high emission reduction potential

Across these mature pathways, rLG typically deliver substantially lower life-cycle GHG intensities than fossil comparators, making them a meaningful decarbonisation option in applications where direct electrification or network-based alternatives are not feasible in the near term. Figure 4 compares life-cycle emission intensities (gCO_2e/MJ) for conventional heating oil, LPG and natural gas with selected rLG pathways, and also shows the RED fossil comparators[8] used under the EU Renewable Energy Directive for regulatory accounting.

The Figure displays both reported ranges and corresponding default values for rLG pathways.[9] These ranges reflect differences in feedstock characteristics, conversion efficiencies, system boundaries, co-product treatment, and the carbon intensity of key energy inputs, in particular electricity and hydrogen. Across all cases, rLG values lie well below fossil fuel benchmarks and RED reference values, highlighting their potential to deliver near-term emissions reductions while leveraging existing liquid fuel infrastructures and appliances.[10]

8 RED fossil comparators are standardised reference values defined under the EU Renewable Energy Directive to calculate percentage GHG savings for compliance purposes; they do not represent specific real-world fuel supply chains.

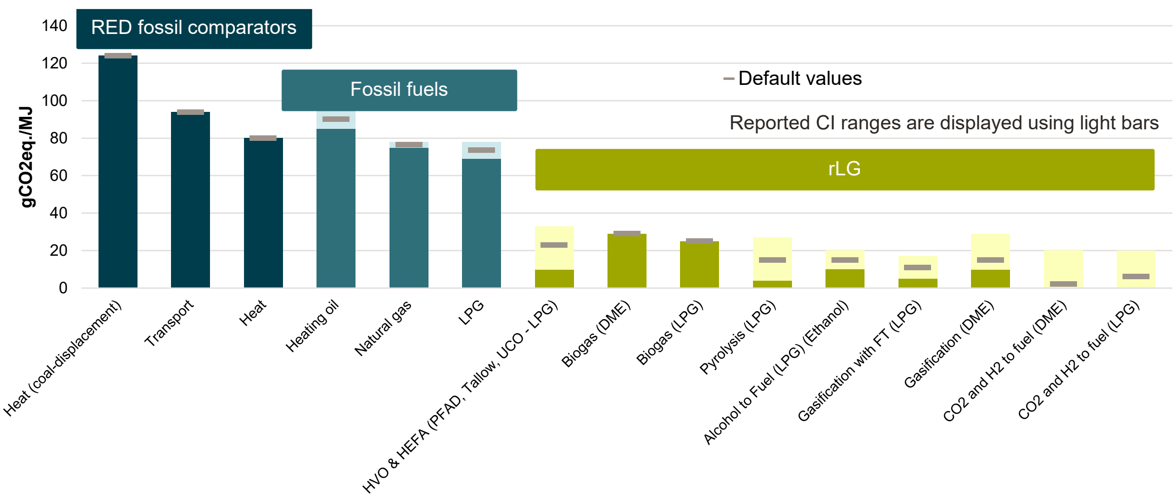
9 Ranges and default values are based on a comprehensive meta-study by Atlantic Consulting (2022): *Carbon Intensities – Renewable and Fossil Liquid Gases: LPG & DME.* Final Report that synthesises more than 400 publicly available carbon-intensity estimates across renewable liquid fuel pathways. Default values represent representative lifecycle GHG intensities used in this White Paper as approximate base-case figures for high-level comparison and public discussion rather than project-specific performance. While some studies report very low or even negative lifecycle emissions, for example where carbon capture and storage (CCS) is applied or where certain waste feedstocks are treated as having zero carbon content at the point of collection, such values are not shown quantitatively due to remaining methodological and accounting uncertainties.

10 Reported carbon intensities for BioLPG produced via the HVO/HEFA route span a wide range in the literature, from approximately 5 gCO_2e/MJ at the lower end to values approaching 80 gCO_2e/MJ under certain feedstock and configuration assumptions (see Atlantic Consulting (2022)). For the purpose of this assessment, however, only feedstocks that comply with EU sustainability criteria under the Renewable Energy Directive (RED) are considered, namely used cooking oil (UCO), tallow and PFAD. As shown in Figure 4, the carbon intensity range illustrated for these RED-compliant, waste- and residue-based pathways extends up to approximately 33 gCO_2e/MJ. This upper bound reflects conservative modelling assumptions within the compliant feedstock set. UK RTFO data for 2024 provide an empirical benchmark for these pathways. Reported carbon intensities for waste-based HVO are approximately 16 gCO_2e/MJ for UCO-based production and between 21 and 22.8 gCO_2e/MJ for tallow-based pathways, with 22.8 gCO_2e/MJ representing the highest reported value in the dataset. Although reported carbon intensities for BioLPG (biopropane) as a HEFA co-product are typically lower (around 5–13 gCO_2e/MJ depending on allocation assumptions), we adopt a conservative default value of 22.8 gCO_2e/MJ. This value lies below the upper bound of the compliant range shown in the figure (33 gCO_2e/MJ) but corresponds to the highest empirically observed UK value for RED-compliant, waste-based production, thereby ensuring that emission reduction potential is not overstated. Ireland RTFO 2024 datapoint shows a much lower carbon intensity of waste-based bioLPG 4.7 - 5.5. gCO2e/MJ which primarily comes from UCO.

rLG can reduce lifecycle emissions versus fossil LPG by approximately 70% based on currently mature waste-based HVO/HEFA production pathways, using a conservative default value of 22.8 gCO_2e/MJ compared to a fossil LPG benchmark of around 73 gCO_2e/MJ.

Future renewable pathways based on renewable electricity and captured CO_2 have the potential to achieve near-zero lifecycle emissions, enabling reductions of up to ~100% relative to fossil LPG once deployed at scale.

Figure 4 CO_2 emission fossil fuel comparators and rLG



Source: Frontier Economics based on European Commission and Atlantic Consulting (2022) and UK RTFO data for 2024

Note: CI values for biogas (DME) and biogas (LPG) based on actual operating plants are rather limited, in practice a considerable spread around the stated CI figures can be expected which depends on the type of feedstock used alongside other factors

3 Outlook: Demand & supply of rLG in Europe

3.1 Current demand for liquid gases in Europe and how this could evolve

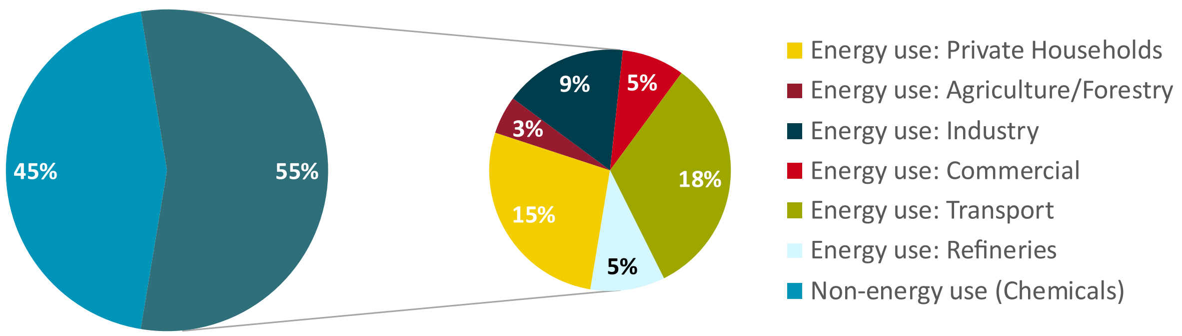
To assess the potential of rLG in Europe's energy transition, we develop an indicative outlook for the liquid gas market to 2040, starting from today's LPG use as the baseline. Using a transparent set of sector-level assumptions, we derive ranges for how much residual liquid gas demand could remain – and what share of that demand could plausibly be met by rLG under different scenarios. We then compare these demand ranges with Liquid Gas Europe's supply scenarios to assess the potential balance between rLG availability and remaining liquid gas needs. While our quantitative assessment focuses on 2040, we also show supply projections to 2050 for context, as they illustrate the potential longer-term scale-up and technology mix shift beyond the core analysis horizon.

Our aim is not to produce a single point forecast, but to provide a practical and credible view of the likely direction of travel and the broad order of magnitude of change.

3.1.1 Current LPG demand is concentrated in a few key sectors

Today's LPG market provides the baseline for assessing where rLG could be deployed. In 2024, total LPG demand across the EU-27 plus the United Kingdom, Switzerland and Norway was around 29.9 Mt. Overall, LPG demand is split between non-energy use[11] (around 45%) and energy use (around 55%) (Figure 5), implying around 16.5 Mt used for energy purposes. In this White Paper, we focus on energy uses and assume that rLG is primarily allocated to these segments, while acknowledging that some limited volumes could also flow to non-energy applications.

Figure 5 Distribution of LPG consumption across energy and non-energy uses, EU27+UK, NO, CH, 2024



Source: Frontier Economics based on Argus Media (2025).

[11] Non-energy LPG use is mainly in the chemical industry, where LPG is used as a feedstock in the production of hydrocarbons (e.g. ethylene)

Within energy use, demand is concentrated in a small number of end-use sectors. Transport and households represent the largest segments, reflecting today's role of LPG as both a transport fuel and an off-gas-grid heating option. Industrial energy use (including refineries) accounts for a further material share, with commercial services and agriculture/forestry representing smaller portions. This sector structure provides a practical basis for assessing where rLG can deliver the highest value, particularly in segments where liquid gas remains structurally relevant and alternatives face constraints.

3.1.2 The future (r)LG demand will evolve differently across relevant sectors

Looking ahead to 2040, we use today's LPG demand for energy purposes as the baseline to estimate how much residual liquid gas demand could remain – and, in turn, what scale of rLG demand this could translate into. We develop an indicative outlook using a transparent set of sector-level assumptions on electrification, efficiency improvements and structural market trends.

Importantly, future rLG demand is not simply what is left of today's LPG consumption after electrification and efficiency gains. It may also include additional volumes driven by fuel switching from more carbon-intensive fuels, particularly oil, to rLG in off-gas-grid or otherwise constrained settings where full electrification may be difficult in the near term. For example, we consider potential additional rLG demand from off-gas-grid households that currently rely on oil for heating. A similar dynamic may also apply in parts of industry, where fuel switching from more carbon-intensive energy carriers could generate additional rLG demand. These potential industrial switching volumes are not explicitly quantified at this stage, making the overall demand estimate conservative. However, as shown in later chapters, there are industrial segments where rLG can represent a viable alternative in fuel-switching contexts, particularly where other decarbonisation pathways face technical or economic constraints.

Figure 6 summarises the resulting sector outlook and suggests a reduction of around 30–45% by 2040 compared with today. The underlying assumptions and sensitivities are set out in Chapter 1 of the technical annex.

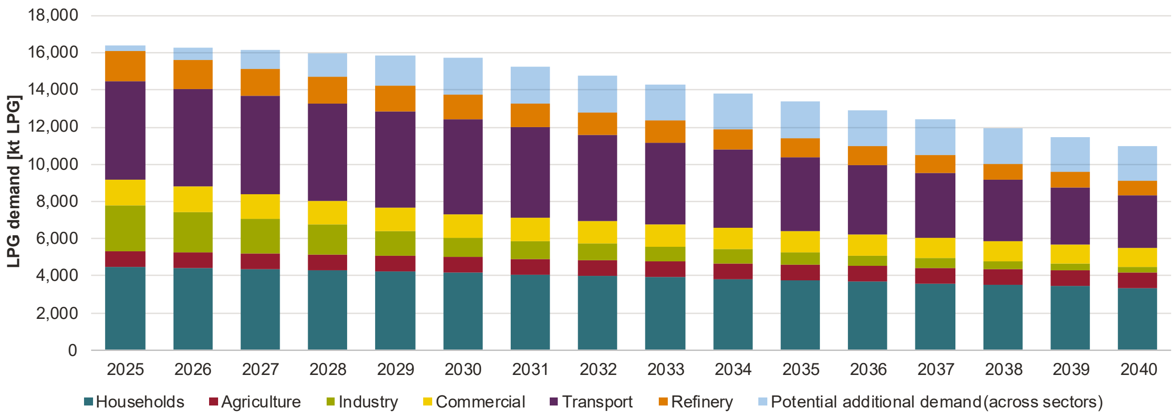
On this basis, Figure 6 implies a broad-based decline across sectors, with residual demand concentrated where liquid gas remains structurally relevant:

- **Households**: demand declines as heating systems are replaced over time, but residual off-gas-grid heating needs remain, especially in harder-to-treat buildings where retrofit requirements and local grid capacity can constrain full electrification. To capture this, we distinguish three stylised household segments in the underlying analysis (current LPG-heated homes, off-gas-grid oil-heated homes that may switch to LPG, and a small share of gas-heated homes affected by potential grid decommissioning).
- **Industry (incl. refineries)**: demand trends down as electrification and efficiency improvements progress, but residual process-heat niches persist, particularly in higher-temperature or retrofit-constrained settings.

- **Commercial services**: demand generally follows the broader heat decarbonisation trajectory, with remaining pockets where site constraints make full electrification more challenging.
- **Agriculture and forestry**: demand declines with efficiency improvements and fuel switching, but some decentralised heat uses remain relevant in off-gas-grid settings.
- **Transport**: LPG use decreases over time as the fleet turns over; it is reflected in the sector totals, but is not the primary focus of this White Paper.

Full assumptions on renovation rates, switching behaviour and sector sensitivities are set out in Chapter 1 of the technical annex.

Figure 6 Projected liquid gas demand for energy purposes, by sector



Source: Frontier Economics

Note: Shaded areas indicate additional demand potential in a scenario with high demand. Projected demand includes both fossil LPG and rLG.

The share of rLG within residual liquid gas demand will be determined by sector-specific blending choices and the way available rLG volumes are allocated across end uses. In practice, this means rLG demand will reflect a combination of (i) total liquid gas demand in each sector and (ii) policy, commercial and operational decisions about where rLG is prioritised (for example, households versus industrial process heat), given constraints on supply.

3.2 Outlook for European rLG supply

We estimate European renewable liquid gas production at around 200 kt in 2025. This is based on recent EU renewable diesel and SAF production of around 3.3 Mt[12] and an assumed 6% renewable rLG co-product yield. This assumption is intended to be conservative and sits between indicative estimates from public sources.[13]

12 United States Department of Agriculture (2024): *Biofuels Annual*. Available here. Accessed: March 2026.

13 SHV Energy indicates a co-product ratio of 5%, while Liquid Gas Europe (2025) suggests a co-product ratio of around 8%.

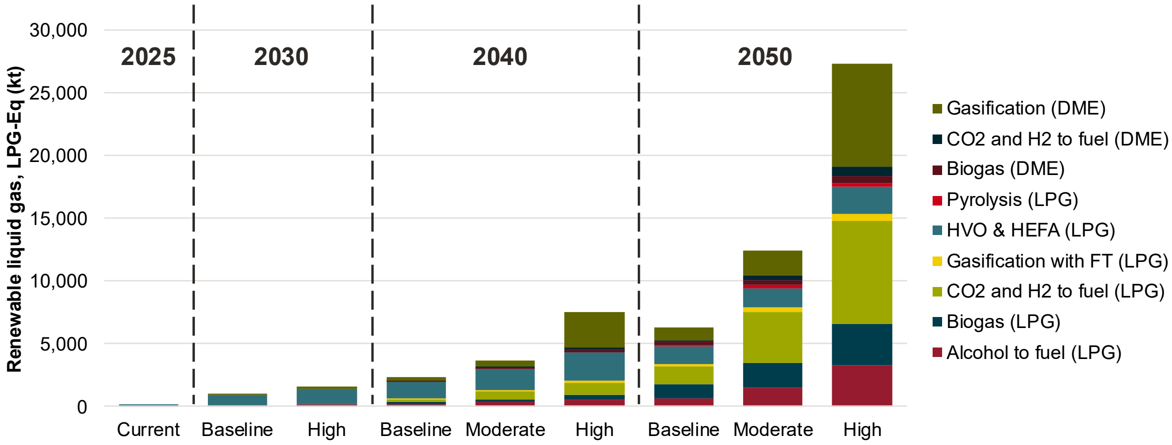
For the outlook on European rLG production potential to 2050, we mainly rely on Liquid Gas Europe ("LGE", 2025). For 2030, we use LGE's estimate of 532 kt[14] from currently operational plants as a lower bound for renewable liquid gas production. To derive a sensible range for rLG supply in 2030, we use EASA's SAF market scenarios as a proxy for growth in the wider HVO/HEFA sector, and apply the same 6% co-product ratio. EASA projects EU SAF capacity increasing from just over 1 Mt today to 3.2 Mt in a realistic 2030 case and 5.6 Mt in an optimistic case[15]. Because the LGE lower bound already captures some expansion of existing plants to 2030, we use a conservative assumption and apply only half of this sector-wide growth when scaling renewable liquid gas output. On that basis, a 2030 range of around 1.0 to 1.6 Mt appears reasonable. By 2040, LGE's projections for European liquid gas supply show further scale-up in renewable liquid gases, reaching a total production volume of 2.3 to 7.5 Mt depending on the scenario. This continues to increase to around 6 to 27 Mt by 2050 with the upper end of the range being achieved under more supportive conditions. The pathway mix broadens over time, shifting from today's reliance on lipid-based routes towards a more diversified set of technologies, including greater contributions from waste-based gasification and power-to-liquid style routes (using CO_2 and hydrogen).

The 2040 outlook remains anchored by HVO/HEFA co-production (renewable LPG as a by-product of renewable diesel and SAF processes), providing roughly half of supply in the baseline and moderate cases, with gasification-to-DME typically the second-largest contributor at around 10 to 15%. Smaller shares come from CO_2 and H_2-to-fuel (LPG), biogas-to-LPG, and modest volumes of DME from CO_2/H_2 or biogas. In the high-supply case, the mix becomes more balanced, with gasification-to-DME rising to more than a third of volumes, while HVO/HEFA falls to around a quarter. This indicates that additional growth increasingly depends on scaling alternative feedstocks and technologies beyond lipids. A key constraint is that access to oily feedstocks is expected to limit the continued growth of HVO/HEFA through the 2030–2040 period, reinforcing the need for other pathways to carry incremental volumes.

14 Liquid Gas Europe (2025)

15 European Union Aviation Safety Agency (EASA) (2024), Sustainable Aviation Fuel (SAF) Market Outlook. Available here. Accessed: March 2026.

Figure 7 European rLG production scenarios by pathway, 2040 and 2050



Source: Frontier Economics based on Liquid Gas Europe (2025)

By 2050 – shown here for contextual reference rather than as the core assessment horizon – the mix shifts further away from lipid dependence. In the baseline and moderate cases, CO_2 and H_2-to-fuel (LPG) and biogas-to-LPG expand their shares, together forming a sizeable portion of supply. HVO/HEFA plays a smaller role than in 2040. In the high-supply case, gasification-to-DME becomes the largest contributor alongside CO_2 and H_2-to-fuel (LPG). The remainder is spread across biogas-to-LPG, alcohol-to-fuel, and smaller DME pathways. This evolution is consistent with expectations that tighter mandates for and broader deployment of sustainable aviation fuel (SAF) increase co-product availability. At the same time, biomass gasification and power-to-liquid routes become commercially crucial as feedstock availability becomes a binding consideration and power-to-liquid options mature towards 2050 (subject to access to low-cost renewable electricity and CO_2).

3.3 Demand–supply alignment to 2040

Bringing the demand and supply projections together suggests that rLG could make a material contribution to Europe's remaining liquid gas needs by 2040, but is unlikely to fully cover them under most pathways. On the demand side, our projections indicate that LPG demand for energy purposes declines steadily with electrification and efficiency improvements, reaching around 9 to 11 Mt by 2040. This reflects the expectation that liquid gases retain a role in harder-to-electrify heat applications and in parts of the existing Autogas fleet, even as total LPG demand for energy purposes declines.

On the supply side, Liquid Gas Europe's outlook points to a wide range of possible European production volumes by 2040, from around 2.3 Mt to a high-supply case of 7.5 Mt. This implies that under the high-supply scenario, 2040 rLG supply could cover roughly 70 to 80% of projected demand for energy purposes. This highlights that supply growth could enable substantial decarbonisation within the liquid gas market, while also indicating that additional measures (such as imports, faster technology scale-up, or stronger demand reduction) would be required to close any residual gap in higher-demand scenarios.

In practice, this implies that rLG deployment is constrained primarily by production capacity, with demand assumed to adjust to the level of supply through blending choices and sectoral allocation. Importantly, these supply volumes are contingent on enabling conditions being in place, including predictable demand at expected rLG production cost, regulatory clarity and the availability of sustainable feedstocks and supporting infrastructure across the value chain.

4 Economic viability: End-use assessment of rLG

Building on the demand and supply outlook, this chapter assesses the economic viability of liquid gases, in particular rLG, relative to alternative low-carbon space heating and industrial heat options. While first establishing a robust price outlook for LPG and renewable liquid gases, we then focus on cost analysis at application level. We focus on two use cases:

- The **total cost of ownership (TCO) of liquid gas use in residential heating** technologies compared with electrification options, and
- The **total costs of liquid gas use in selected industry processes** compared with relevant electrification options.

While these results showcase important insights into application-level economic viability, they should not be interpreted in isolation. Findings are set out in a case-study approach to demonstrate rLG blends as a viable energy solution at application level. These findings are, however, substantially complemented by the subsequent chapter, which assesses system-level implications. In particular, one of the key strengths of liquid gases lies in their suitability for off-gas-grid and niche applications, where they can avoid substantial infrastructure investments that are not captured at application-level cost comparisons.

4.1 Costs for rLG will decrease once markets ramp up

4.1.1 Methodological approach

To establish a consistent basis for comparing rLG with alternative technologies, we first derive indicative end-user price ranges for the renewable liquid gases of choice.

Costs are estimated for three points in time – 2025, 2030 and 2040 – to capture near-term conditions as well as plausible medium-term developments. We consider three different countries as case studies, based on their current prominent use of liquid gases. For each pathway, we derive country-specific end-user prices by starting from a wholesale cost benchmark and applying consistent assumptions on distribution margins, taxes, and levies.[16]

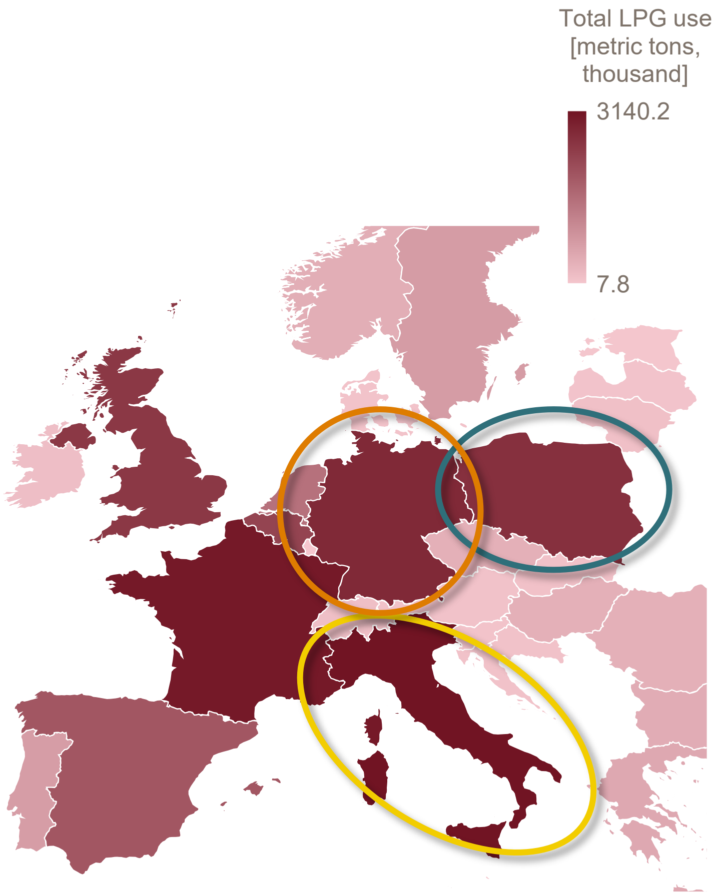
[16] Energy taxes and VAT are held constant in real terms over time, while a harmonised carbon pricing framework is assumed from 2030 onwards. Renewable liquid gases are assumed to be exempt from carbon pricing.

Choice of reference countries

The analysis focuses on **Germany**, **Poland**, and **Italy** as case-study countries to illustrate how the economic viability of rLG varies across different European contexts. The three countries were selected to reflect:

- a significant existing use of liquid gases today (see heatmap);
- a wide range of climatic conditions and resulting heating demand profiles; and
- differing electricity price levels and decarbonisation pathways.

Together, these countries provide a representative cross-section of conditions under which liquid gas is currently used, allowing the results to illustrate how relative cost competitiveness depends on national circumstances rather than to provide directly comparable country rankings.



Source: Frontier Economics

Note: LPG use data via Argus Media (2025).

Projected cost reductions are driven by assumptions on learning effects (where technology not yet mature), declining wholesale margins as rLG markets scale, and modest reductions in operating costs linked to energy input prices. Biogenic feedstock costs are generally held constant or assumed to decline only slightly, reflecting uncertainty around future biomass availability. More information on the methodology can be found in Chapter 2 of the technical annex of this White Paper.

To reflect realistic market uptake, subsequent application-level analyses are based on a central liquid gas blend, in which the share of rLG relative to conventional LPG increases gradually over time, rather than assuming an immediate switch to 100% renewable supply.

All costs are expressed in real terms and reported in 2025 euros.

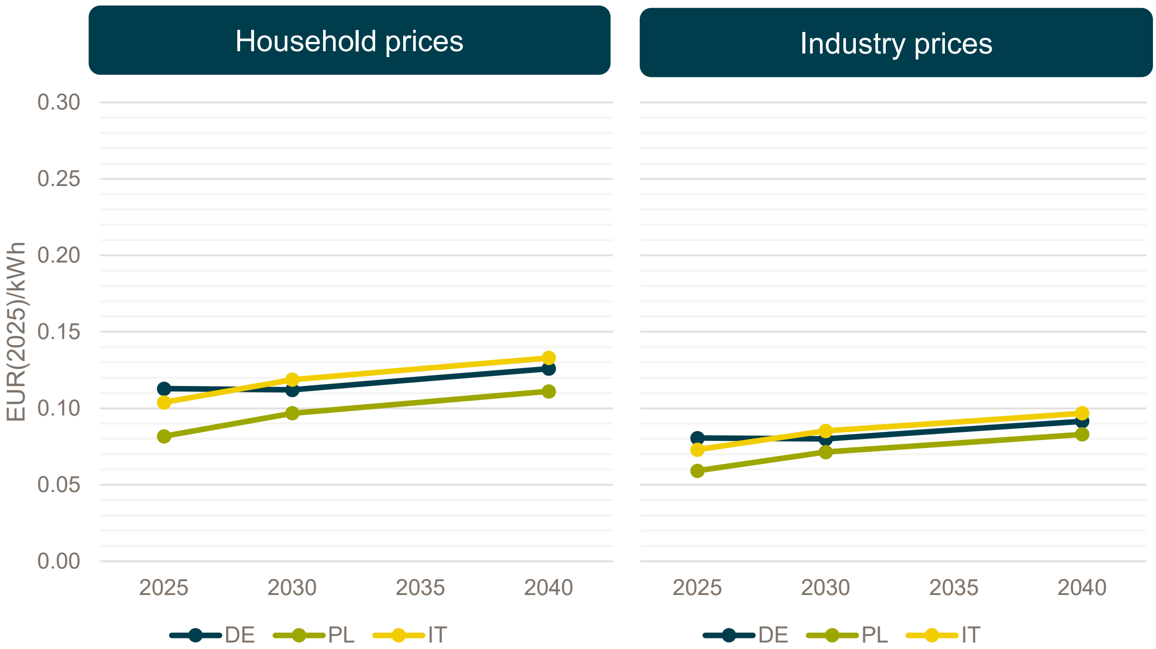
4.1.2 LPG will face higher carbon levies in the future, increasing LPG prices

Fossil LPG serves as the reference point for deriving rLG (blend) end-user prices. We construct country-specific LPG prices by starting from observed household and industrial LPG prices and deducting energy taxes, VAT, and existing carbon levies. The resulting net supply price is then compared with a consistent wholesale benchmark to infer country-specific distribution and retail margins.

Wholesale LPG prices are projected in line with crude oil price developments from the World Energy Outlook 2025 (Net Zero scenario)[17], reflecting the close linkage between LPG and oil markets. For industrial users, distribution margins are reduced to reflect economies of scale and lower costs for logistics.

This approach ensures that rLG price estimates are directly comparable to observed LPG prices and reflect realistic country-specific market structures. The resulting prices are shown in Figure 8.

Figure 8 Price forecast for conventional LPG



Source: Frontier Economics

Note: Prices for industrial consumers are reported excluding VAT, whereas household prices include VAT. Moreover, economies of scale in distribution costs are taken into account for industrial customers. Further details are set out in the technical annex.

Germany already applies a national CO_2 levy in 2025 under the BEHG, which will be replaced by the harmonised ETS 2 for all member states in subsequent years. As a result, early-phase carbon price developments (and therefore, LPG price developments) differ in Germany compared with Poland and Italy. This is why the prices for Italy and Poland increase between 2025 and 2030, while it decreases for Germany.

Driven by rising carbon prices, fossil LPG prices are expected to increase over time for both household and industrial users.

17 International Energy Agency (2025): *World Energy Outlook 2025.* Paris. Available here. Accessed: February 2026.

4.1.3 Costs for the liquid gas blend estimate increase as its green value increases

End-user prices for rLG are derived by applying a pathway-specific mark-up to the fossil LPG supply price, reflecting the higher production costs of renewable feedstocks. This mark-up is determined via wholesale price calculations of rLG. This differential is added consistently across countries, with analogous treatment of taxes and levies and the assumption that no carbon pricing is applied to rLG. More details on the prices for each rLG pathway can be found in Chapter 2 of the technical annex.

In practice, rLG will not be introduced as standalone fuels replacing fossil LPG overnight and at large scale. Instead, the transition towards low-carbon liquid gases is expected to occur through gradually increasing blends of fossil LPG and renewable liquid gas pathways. To reflect this likely market development, we combine the pathway-specific cost estimates[18] into a central liquid gas blend with an increasing renewable share over time. This blend is designed to capture the directional cost impact of increasing rLG availability, rather than to represent actual market shares.

This renewable blend used in the TCO analysis should not be interpreted as a forecast of overall rLG market penetration. System-wide penetration reflects aggregate supply availability relative to total LPG demand. By contrast, the blend represents the renewable share purchased by an individual consumer under an illustrative contracting scenario – whether household or industrial.

Even where overall market penetration is low, it is technically feasible for individual households and industrial users to source a significantly higher renewable share, including up to 100%. The blend therefore reflects a potential purchasing choice rather than an economy-wide penetration rate. For consumers with a higher willingness to pay for rapid decarbonisation, rLG can also offer a pathway to reduce the carbon intensity of energy use more quickly than waiting for the full decarbonisation of the electricity mix.

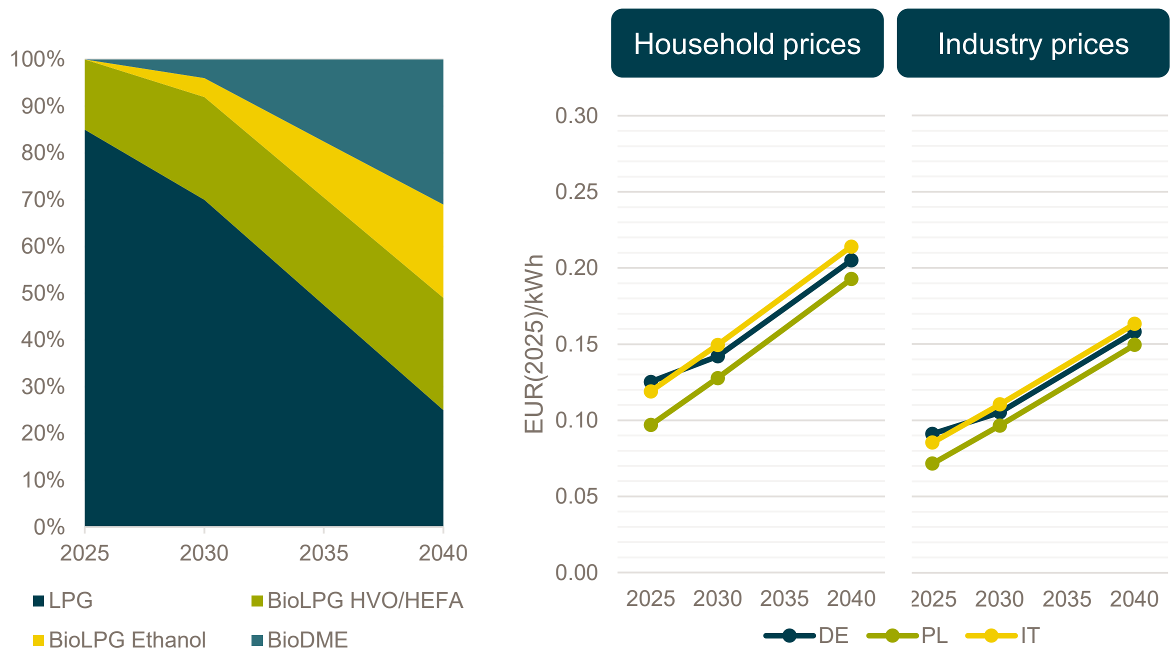
Importantly, the blend is not calibrated to projected system-wide volumes in any given year. Given that demand forecasts remain indicative in this White Paper and outlooks remain assumption-based, we do not attempt to calibrate blends to system-wide volumes. The blended pathway therefore provides a transparent and internally consistent modelling framework, without implying a forecast of market penetration or deployment rates.

In the near term, the blend is dominated by fossil LPG and mature renewable pathways, in particular bioLPG produced via the HVO/HEFA route. Over time, less mature but potentially higher availability pathways, such as bioLPG via ethanol and bioDME, gain a larger share as deployment expands and costs decline. The fossil volume share stands at 85% in 2025, which decreases to 25% in 2040. By 2050, the blend would be based solely on rLG.

18 These are presented in detail in the technical annex.

The LG blend is constructed separately for household and industrial users, applying the same principles used in the pathway-specific analysis. The resulting blended prices therefore represent indicative end-user prices under a plausible transition pathway, rather than a forecast of any specific regulatory or contractual arrangement. They are shown in Figure 9.

Figure 9 Blend composition and price forecast for central LG blend



Source: Frontier Economics

The resulting blended liquid gas prices show a moderate and gradual increase in the renewable content of liquid gas supply over time, while avoiding sharp price discontinuities. Although the increasing share of renewable components exerts upward pressure on prices relative to fossil LPG, this effect is partly offset by declining rLG production costs.

The central liquid gas blend provides a consistent reference point within the wider cost range implied by different liquid fuel choices and renewable shares, and is used as the basis for the subsequent application-level analyses in this White Paper.

4.2 rLG for residential heating constitutes a viable low-carbon option for certain building types

4.2.1 Methodological approach

The economic viability of rLG in residential heating[19] is assessed using a **total cost of ownership (TCO) framework**. Costs are expressed as average annual costs over the lifetime

[19] This covers both space heating and warm water needs.

of each heating technology, assuming the investment is made in the year shown.[20] This captures both annualised upfront capital expenditure and ongoing operating costs, i.e. both O&M and energy costs. All costs are valued for the year of investment indicated, for three different years of consideration – 2025, 2030 and 2040.

The comparison focuses on rLG-based boilers versus air-source heat pumps.[21] The analysis abstracts from subsidies, preferential tariffs, and support schemes to ensure a technology-neutral comparison based on underlying cost structures. It is important to note that actual household costs might therefore differ from the costs presented.

We assess representative single-family houses in Germany, Poland, and Italy that reflect building types for which liquid gas solutions are most relevant, typically located in rural or potentially off-gas-grid areas. The buildings are characterised by:

- A comparable, relatively old construction period window across countries,
- Average insulation levels[22], and
- Radiator-based heat distribution systems.

Based on these criteria, the selected reference houses are drawn from the European building typology database (TABULA)[23], representing average buildings in each country that meet the specified characteristics.

Country-specific heating demand via the When2Heat database[24] is held constant over time for each building type, i.e. only changes in cost structure drive cost changes over time.[25] Operating costs are derived by combining country- and building-specific thermal load profiles with technology-specific efficiency assumptions, including temperature-dependent COP profiles for heat pumps for each building/country.[26] Heat pumps are modelled for bivalent operation, enabling optimised sizing combined with an electric immersion backup heater.[27] We

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20 As an example, the 2025 cost reflects the average annual cost of a technology installed in 2025 over its full 20-year lifetime (to 2044 incl.), including changes in energy prices over time.

21 Our analysis also covered ground-source heat pumps. We do not present the results here for brevity, as the overall conclusions are unchanged.

22 This equals energy performance level 2 in the building typology database TABULA ("standard refurbishment").

23 Accessible via webtool.

24 Ruhnau, O., Muessel, J. (2023). When2Heat Heating Profiles. Open Power System Data. https://doi.org/10.25832/when2heat/2023-07-27.

25 These are based on the standard weather year 2019. It is worth noting that this neglects weather patterns and therefore heating patterns changing over time. Moreover, this also indicates a constant house insulation is assumed over time.

26 Both are also sourced via the When2Heat database.

27 The heat pump is sized so that it can cover thermal demand in 95% of the hours of the year.

consider heat pumps with high flow temperatures, reflecting the radiator-based heat distribution in older, moderately insulated buildings.[28]

4.2.2 Total cost of ownership per country

The German reference single-family house has a floor area of 121 m² and a peak heating demand of 7.9 kW. Under bivalent operation, the heat pump is sized at 5 kW.[29] The resulting average cost of ownership is shown in Figure 10.

If a new heating system is installed in the reference house in 2025, the average annualised total cost of ownership over its lifetime is around €2.9k per year for an LPG boiler, €4.5k for an air-source heat pump, and €3.9k for a boiler using the central rLG blend assumption. Costs can increase to up to around €5.8k per year in a scenario with 100% rLG throughout the lifetime, reflecting a higher-cost option for consumers with a greater willingness to pay to decarbonise more rapidly.

28 Renovation costs are outside the scope of this White Paper. Building fabric upgrades are highly heterogeneous, strongly context-specific, and provide benefits that extend beyond heating – most notably through impacts on overall building quality, comfort, and property value. As a result, such investments cannot be robustly attributed to heating alone.

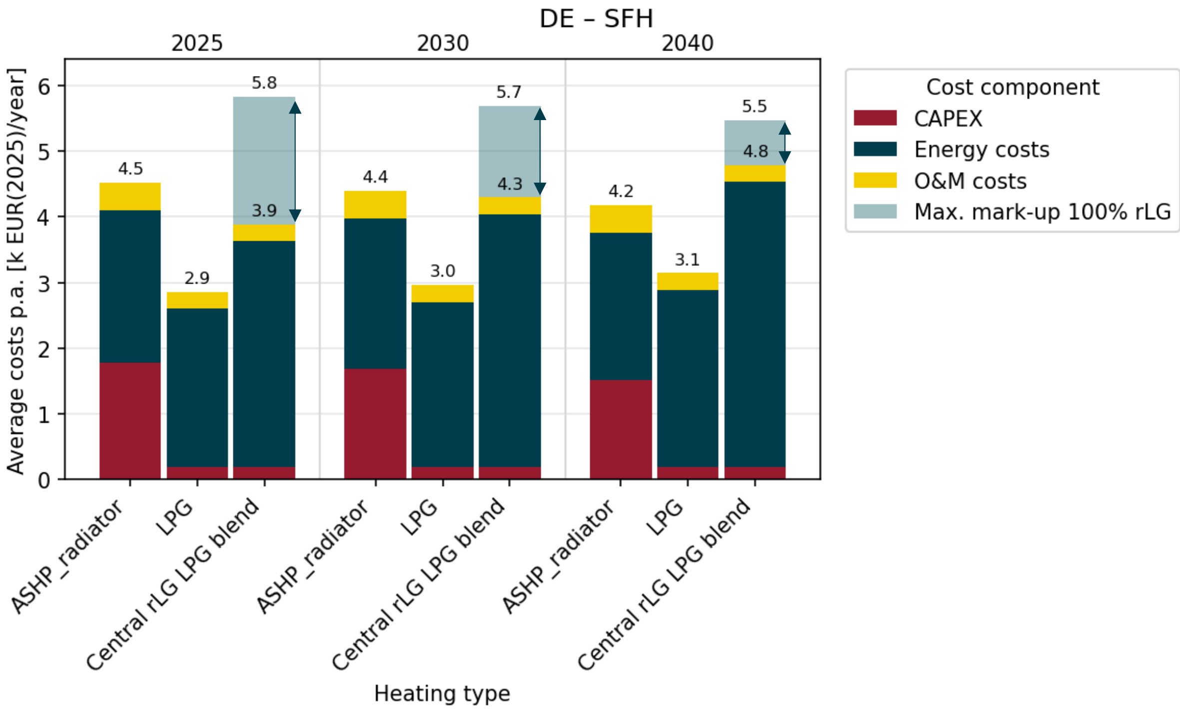
29 Through bivalent operation, heat pump capacity is sized to match the 95% percentile of annual thermal load.

Figure 10 German reference house and associated heating TCO

Representative **German single-family house** constructed **between 1958 and 1968**, assuming an **average renovation rate***.

Reference floor area of **121 m²**, with

- a thermal demand for space heating of 133 kWh(th)/m², and
- a thermal demand for domestic hot water of 800 kWh(th) per person (for 3 persons).



Source: Frontier Economics, building information / picture via TABULA.

Note: Costs shown represent annualised capital expenditure as well as average energy and operation and maintenance costs per year, assuming a heating technology lifetime of 20 years starting in the indicated year of investment. The detailed calculation methodology is set out in the technical annex of this White Paper. The analysis draws primarily on the open-source datasets When2Heat and the TABULA building typology, complemented by assumptions on relevant cost structures. The "max. mark-up 100% rLG" represents the additional cost required to move from the central blend to the most expensive rLG pathway in our analysis (bioDME).

ASHP_radiator: Air-source heat pump with radiator-based heat distribution.

** Equals energy performance level 2 ("standard refurbishment") in TABULA.*

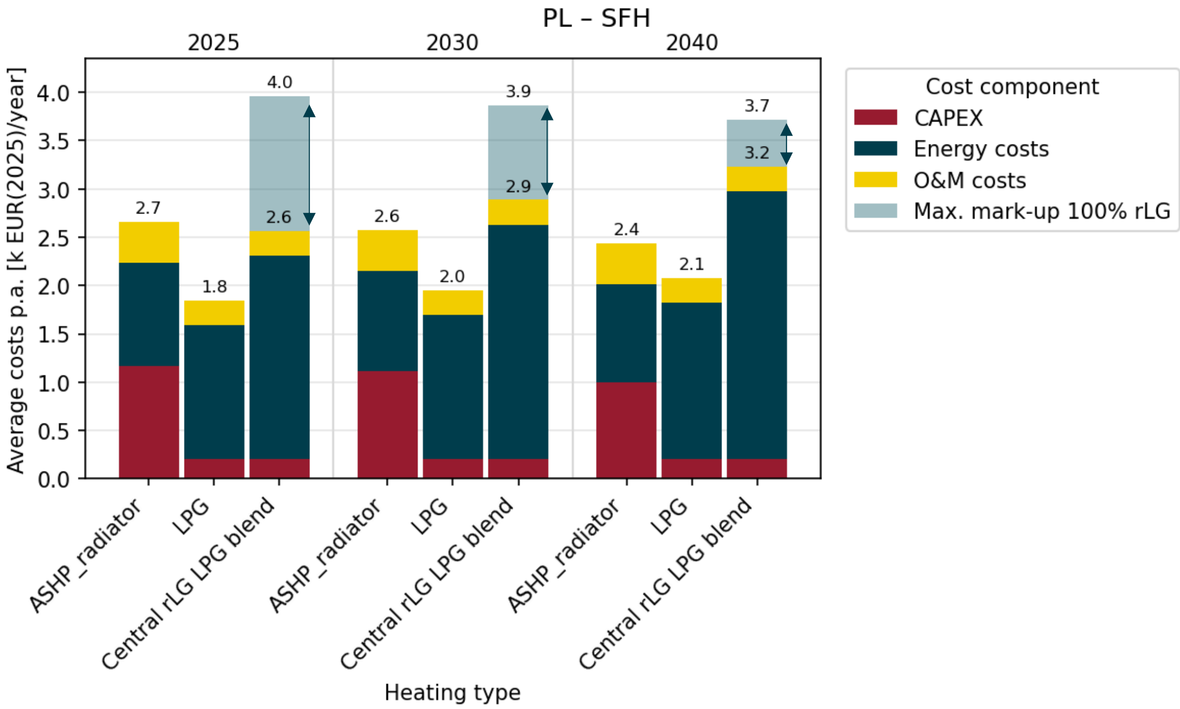
The Polish reference single-family house has a floor area of 98 m² and a peak heating demand of 5.2 kW. Under bivalent operation, the heat pump is sized at 3.3 kW.[30] The resulting total cost of ownership is shown in Figure 11.

Figure 11 Polish reference house and associated heating TCO

Representative **Polish single-family house** constructed **between 1946 and 1966**, assuming an **average renovation rate***.

Reference floor area of **98 m²**, with

- a thermal demand for space heating of 104 kWh(th)/m², and
- a thermal demand for domestic hot water of 800 kWh(th) per person (for 3 persons).



Source: Frontier Economics, building information / picture via TABULA.

Note: Costs shown represent annualised capital expenditure as well as average energy and operation and maintenance costs per year, assuming a heating technology lifetime of 20 years starting in the indicated year of investment. The detailed calculation methodology is set out in the technical annex of this White Paper. The analysis draws primarily on the open-source datasets When2Heat and the TABULA building typology, complemented by assumptions on relevant cost structures. The "max. mark-up 100% rLG" represents the additional cost required to move from the central blend to the most expensive rLG pathway in our analysis (bioDME).

ASHP_radiator: Air-source heat pump with radiator-based heat distribution.

** Equals energy performance level 2 ("standard refurbishment") in TABULA.*

[30] Through bivalent operation, heat pump capacity is sized to match the 95% percentile of annual thermal load.

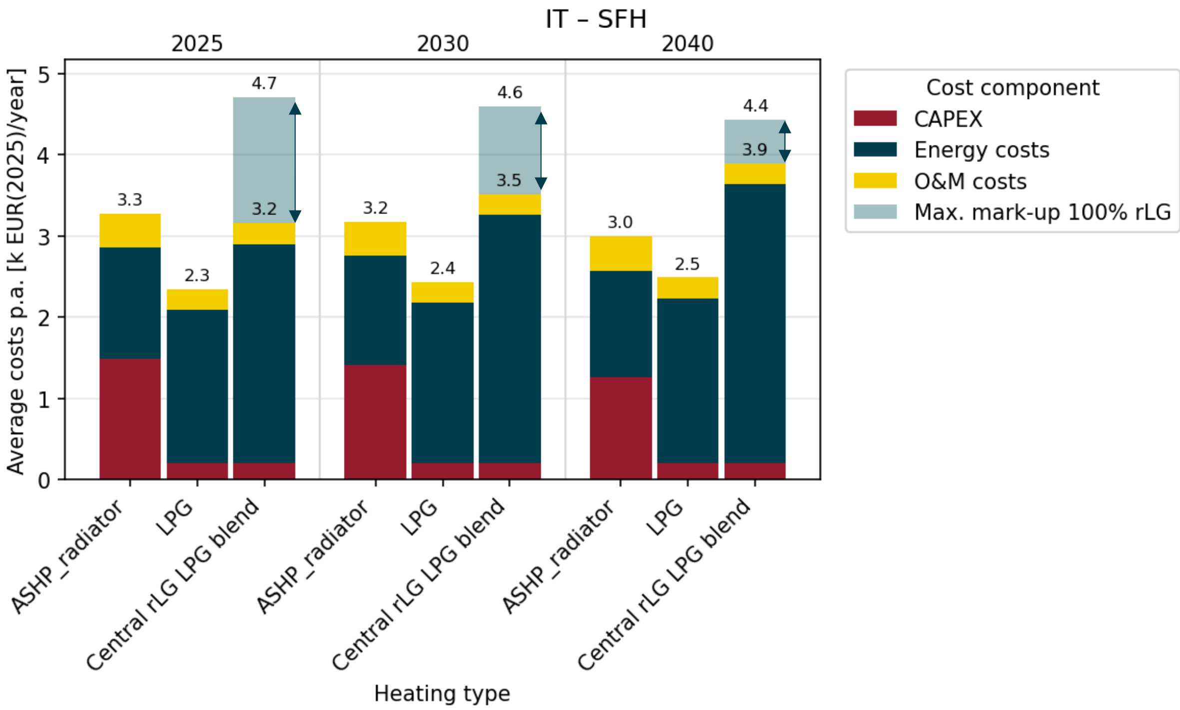
The Italian reference single-family house has a floor area of 162 m² and a peak heating demand of 6.1 kW. Under bivalent operation, the heat pump is sized at 4.2 kW.[31] The resulting total cost of ownership is shown in Figure 12.

Figure 12 Italian reference house and associated heating TCO

Representative **Italian single-family house** constructed **between 1946 and 1960**, assuming an **average renovation rate***.

Reference floor area of **162 m²**, with

- a thermal demand for space heating of 72 kWh(th)/m², and
- a thermal demand for domestic hot water of 800 kWh(th) per person (for 3 persons).



Source: Frontier Economics, building information / picture via TABULA.

Note: Costs shown represent annualised capital expenditure as well as average energy and operation and maintenance costs per year, assuming a heating technology lifetime of 20 years starting in the indicated year of investment. The detailed calculation methodology is set out in the technical annex of this White Paper. The analysis draws primarily on the open-source datasets When2Heat and the TABULA building typology, complemented by assumptions on relevant cost structures. The "max. mark-up 100% rLG" represents the additional cost required to move from the central blend to the most expensive rLG pathway in our analysis (bioDME).

ASHP_radiator: Air-source heat pump with radiator-based heat distribution.

** Equals energy performance level 2 ("standard refurbishment") in TABULA.*

Across all countries considered, rLG-based heating systems are broadly cost-competitive with heat pumps over the assessment period, although as the rLG share in the blend increases towards 2040 a difference does begin to emerge. However, this does not fully reflect wider

[31] Through bivalent operation, heat pump capacity is sized to match the 95% percentile of annual thermal load.

system-level savings (discussed later) or the more favourable cost structure of rLG for consumers. Cost-competitiveness strengthens further when favourable cost structures and wider system-level savings are taken into account.

Liquid gas and heat pump technologies differ markedly in their cost structure. Liquid gas boilers involve significantly lower upfront investment costs than air-source and ground-source heat pumps, allowing higher ongoing energy costs to remain economically viable in total cost terms. While heat pumps benefit from high energy efficiencies, their higher capital costs mean that total annualised costs remain comparable to, or higher than, rLG blend solutions in many cases. Blending rLG can therefore represent an economically efficient option for households seeking to reduce emissions from heating without incurring high upfront expenditures or undertaking major building retrofits.

To reflect different potential decarbonisation pathways and household preferences, we show a range of costs reaching up to 100% rLG, representing an option for households to switch to fully renewable heat depending on their willingness to pay: As noted above, it is technically feasible for individual households and industrial users to source a high renewable share of rLG (including up to 100%), even when overall market penetration remains low. Conversely, heat pumps drawing electricity from the grid will only be fully decarbonised once electricity generation is entirely based on renewable sources. As such, rLG can be a high-value option for fully renewable heating for households with a strong preference for decarbonisation.

4.3 rLG can ensure the viable decarbonisation of certain industrial processes

Industrial energy use remains dominated by fossil fuels and is a major contributor to energy-related CO_2 emissions. Much of this energy demand is for heat, spanning low-temperature needs such as drying processes and steam generation, through to high-temperature processes in metals and minerals production. While electrification is already technically viable for many low- and some medium-temperature applications, the practical constraints increase with temperature and throughput, particularly where electrification implies major redesigns, new hardware, and production disruption.

Heat pumps are a key option for low-temperature industrial heat: large industrial heat pumps can provide roughly 140–160 °C today, with higher temperatures expected as designs improve.[32] This means they can address a meaningful share of industrial heating needs in sectors like food, paper and chemicals, but they are not a universal solution for the full range of process temperatures. Policy is also increasingly targeting industrial process heat

[32] IEA (2022), *The Future of Heat Pumps*, December 2022. Available here. Accessed: March 2026.

decarbonisation, for example through EU-level support mechanisms such as Innovation Fund auctions focused on industrial process heat.[33]

4.3.1 Methodological approach

In a first step, we identify qualitative criteria that influence the likely viability of LPG in industrial heating processes, to facilitate a qualitative pre-selection of processes where rLG may be a relevant decarbonisation option. We then assess the relative economics of electrification against a benchmark fossil LPG application as well as an rLG application as an alternative decarbonisation route. We compare costs on a consistent per-tonne product basis, considering energy cost as well as required capital expenditure based on two main evidence streams. First, we use specific energy consumption and investment cost data from published studies and available pilot project reports. Second, we apply our own forecasts for electricity and LPG prices, as described in the previous section, to ensure consistency with the wider analysis.

The key steps of our assessment are as follows:

- Energy use assumptions: In the absence of robust process-specific LPG data, we assume LPG has the same specific energy consumption as natural gas for the relevant applications.
- Operating cost calculation: For each option, we calculate operating energy costs per tonne of product, combining data on specific energy consumption with our assumptions on fuel and electricity prices (detailed in Chapter 2 of the technical annex). For LPG, we present fossil LPG as the benchmark and a central rLG blend scenario as a decarbonisation pathway.
- Investment cost treatment: We convert upfront investment costs into an annualised cost per tonne of product by annualising CAPEX over a 10-year lifetime using a 5% discount rate, and adding estimated operations and maintenance (O&M) costs where applicable. We are assessing costs from the perspective of a plant that is running on LPG in the status quo, so we assume there are no conversion costs in the fossil LPG or rLG blend scenarios.[34]
- Cost comparison: We then compare the total electrification cost (energy plus annualised investment and O&M) against the energy-only cost of the LPG options.

33 European Commission (2025), Commission Publishes Terms and Conditions for First Pilot Auction for Industrial Heat Decarbonisation. Available here. Accessed: January 2026.

34 We note, however, that DME blends may require minor equipment adjustments (e.g. components in the fuel handling or burner system), which could imply small one-off costs at higher blend shares; given the focus on moderate blends, we do not quantify these costs here.

4.3.2 rLG can be a valuable decarbonisation route for specific industrial niches

A practical way to frame the choice of decarbonisation options is by temperature range (see Figure 13):[35]

- **Below ~200 °C**: decarbonisation opportunities are typically strongest for electrification (heat pumps, electric boilers), often with clear efficiency advantages.
- **~200–500 °C**: electric boilers and direct electric heating (for example resistance heating) can be technically available in many applications and can improve efficiency, but costs depend heavily on electricity prices and site-specific constraints.
- **Above ~500 °C and especially >1000 °C**: electric solutions exist for some processes, but are more frequently constrained by throughput, feasibility of retrofits, and the need for specialised new plant. In these segments, renewable fuels (PtG-type fuels, biofuels and hybrids) become more relevant.

Figure 13 Decarbonisation routes by temperature range

Temperature range	Typical processes	Electrification potential	Potential role for rLG
< 100 °C	**Food**: Evaporation and concentration; **paper**: low temperature drying	Very good decarbonisation opportunities with conventional and industrial high temperature heat pumps (HTHP); clear efficiency advantages over fossil boilers	H2 or other PtG / biofuel options not technically necessary or likely to be niche in this temperature range
100 – 200 °C	**Cross-sector**: steam generation; **food, paper & chemical** e.g. evaporation and drying	HTHPs can reach up to 165°C, electrode boilers are commercially available, offering major efficiency gains → economic viability depends on electricity prices	
200 – 500 °C	**Chemical parks**: steam supply; **metal**: continuous heat treatment of aluminium	Electrode boilers and direct electric heating (e.g. resistance heating) are technically available in many applications and offer efficiency improvements	PtG / biofuels or hybrid systems likely to be relevant, especially for high-throughput plants
500 – 1000 °C	**Steel and non-ferrous metals**: heating and heat treatment; **minerals**: firing of bricks	Electric technologies are available for many applications, but subject to technical and economic constraints, in particular in processes with high throughputs	
1000 – 1500 °C	**Metal and minerals**: heating of steel, melting of aluminium / copper, clinker burning, glass and ceramics	Electric solutions for many processes exist, but often with significantly lower throughput	High relevance of PtG / biofuels in standalone or hybrid systems
> 1500 °C	**Metal and minerals**: high temperature melting processes in iron and glass industries	Some electric alternatives exist (e.g. electric arc furnaces in steel production), but generally electrification is rather niche as it often requires entirely new specialised plants	Very high relevance of PtG or biomass

Source: Frontier Economics based on UBA (2023).

Within this framing, LPG and renewable liquid gas (rLG) can be an attractive option where one or more of the following conditions are met:

1. **Medium-to-high temperature needs**, where heat pumps are not a credible option and full electrification would require major process redesign;
2. **Low-to-medium overall heat demand at site level**, where the business case for a pipeline gas connection (or later hydrogen network connection) is weak, and/or where on-site fuel storage is already common; and

[35] Umweltbundesamt (UBA) (2023): *CO2-neutrale Prozesswärmeerzeugung: Umbau des industriellen Anlagenparks im Rahmen der Energiewende: Ermittlung des aktuellen SdT und des weiteren Handlungsbedarfs zum Einsatz strombasierter Prozesswärmeanlagen*. Available here. Accessed: February 2026.

3. **Limited grid access or constrained electricity supply**, where electrification would require costly grid reinforcement.

This highlights that rLG is not a universal solution for the decarbonisation of industrial heat. In many applications, electrification or grid-based low-carbon gases are likely to be preferable. However, rLG can still play a valuable role in specific industrial niches, particularly where fuel switching avoids the step-change investments required for electrification.

4.3.3 Application-level evidence suggests that rLG can be economically competitive where electrification CAPEX are high relative to efficiency gains

We selected four case-study industrial heating processes to assess the economic viability of rLG across the range of potential rLG applications: Brick firing and asphalt production represent high-temperature, throughput-intensive applications where full electrification is technically possible but typically implies major plant modifications and material CAPEX, making drop-in fuel switching more relevant. Aluminium melting illustrates a high-temperature process where electrification can be implemented with comparatively limited retrofit scope, but the economics can still be dominated by energy price differentials. Distilleries provide a contrasting low-temperature steam and process-heat example where high-temperature heat pumps can deliver large efficiency gains. We discuss these cases in turn below.

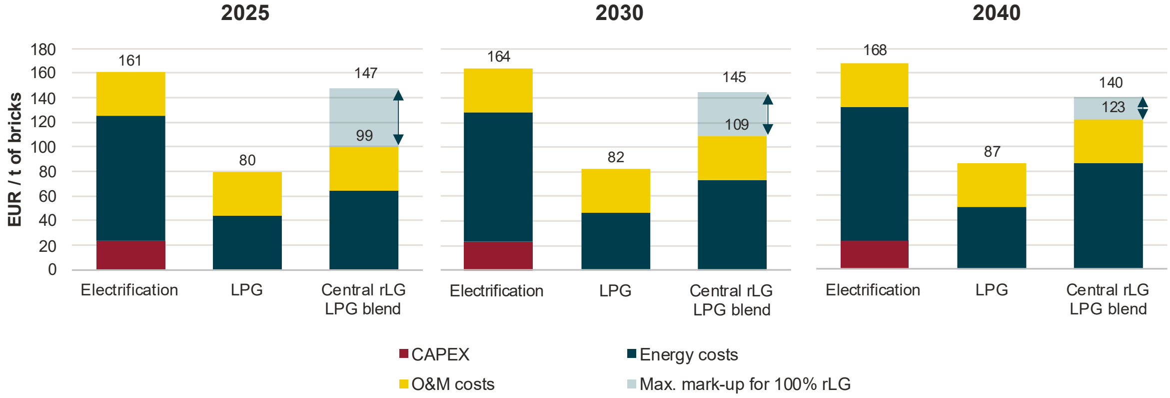
Brick firing requires high process temperatures above 1,000 °C in tunnel kilns, which are usually equipped with open gas burners. While electrification is technically possible, it would typically require either major retrofits to existing kilns or full kiln replacement, both of which entail material capital expenditure and potential installation disruption.[36] Brick-firing plants are often located close to relevant raw material sources, such as clay pits or sand quarries, in order to minimise transport costs. As a result, sites may be less likely to have access to high-capacity energy infrastructure (such as high-voltage grids).

Against this backdrop, our assessment indicates that rLG can provide a pragmatic decarbonisation route for LPG-fired brick plants. Electrification achieves only minor efficiency gains in brick firing applications[37], so that energy costs in EUR per t of bricks are higher in an electrified plant than in a plant running on LPG or an rLG blend. This is amplified by the CAPEX investment required for the electrification of the production process, which amounts to around 23 EUR / t of bricks (annualised over a 10-year lifetime using a 5% discount rate, see Figure 14).

36 UBA (2023)

37 According to UBA (2023), electrification reduces specific energy consumption by around 5% compared to gas-fired applications.

Figure 14 Cost comparison for brick firing processes



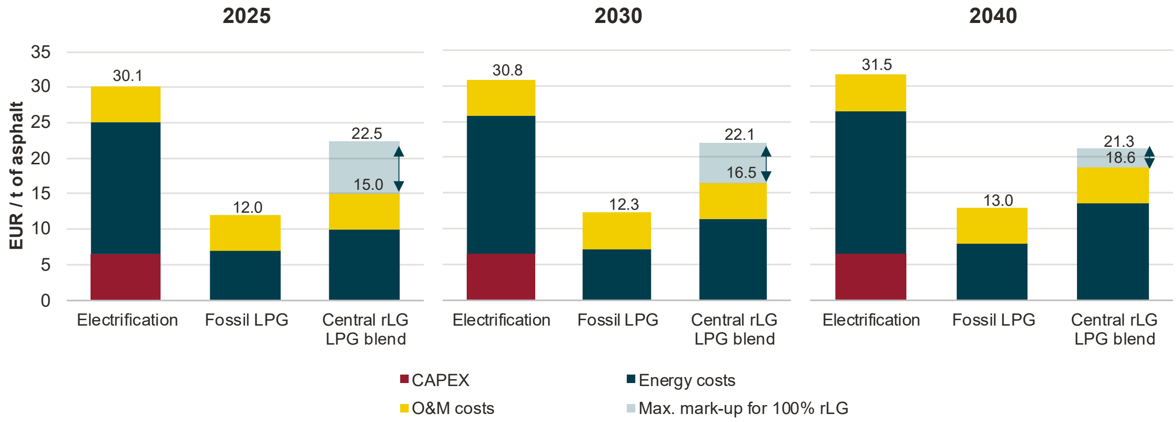
Source: Frontier Economics based on UBA (2023)
Note: Chart is based on energy price forecasts for Germany, results for other case study countries are comparable.

Asphalt production uses substantial amounts of energy for heating and drying the asphalt mix in drum mixers, where aggregates are typically heated in a rotating drum using direct-fired natural gas or fuel oil burners. Electrification of asphalt production is technically possible (for example via electric resistance heating), but it generally involves significant investment to modify or replace core plant components and may also require changes to material handling and process control.[38]

Similar to the brick firing case, our cost comparison suggests that rLG can be a viable decarbonisation alternative for LPG-fired asphalt plants where electrification would require substantial retrofit CAPEX. In this application, electricity-based heat leads to materially higher energy costs per tonne of asphalt under our price assumptions. Adding the annualised investment requirement of around 7 EUR per tonne of asphalt reinforces this result.

38 Oliveira & Silva (2022), *Decarbonisation options for the Dutch asphalt industry*, December 2022. Available here. Accessed: March 2026

Figure 15 Cost comparison for asphalt production processes



Source: Frontier Economics based on Oliveira & Silva (2022)
Note: Chart is based on energy price forecasts for Germany, results for other case study countries are comparable.

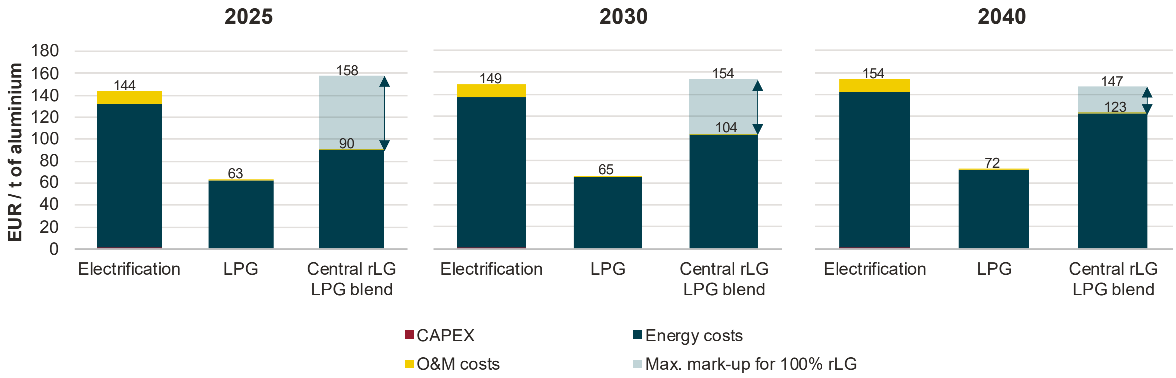
Aluminium melting requires high and stable heat input to melt and hold metal at temperature, typically in gas-fired crucible, reverberatory, or rotary furnaces. Electrification generally requires retrofits or replacement with electric induction or resistance furnaces, alongside upgrades to on-site electrical systems.[39]

According to UBA (2023), electrification of aluminium melting achieves an efficiency gain of around 13% compared to gas-fired heating in terms of specific energy consumption. However, this efficiency gain is not sufficient to offset the higher cost of electricity relative to LPG/rLG under our price assumptions, meaning that operating energy costs remain materially higher in the electrification case than for LPG or an rLG blend. Given that the incremental retrofit CAPEX for electrification is relatively limited in this application[40], the result is primarily driven by operating cost differentials rather than investment costs.

39 UBA (2023)

40 Upfront CAPEX for plant retrofit to convert from gas to electricity is estimated at ~8€ / t of capacity based on UBA (2023). This translates to around 1.5€ of annualised cost per t of capacity, based on a 10-year lifetime and a 5% discount rate.

Figure 16 Cost comparison for aluminium melting processes



Source: Frontier Economics based on UBA (2023)
Note: Chart is based on energy price forecasts for Germany, results for other case study countries are comparable.

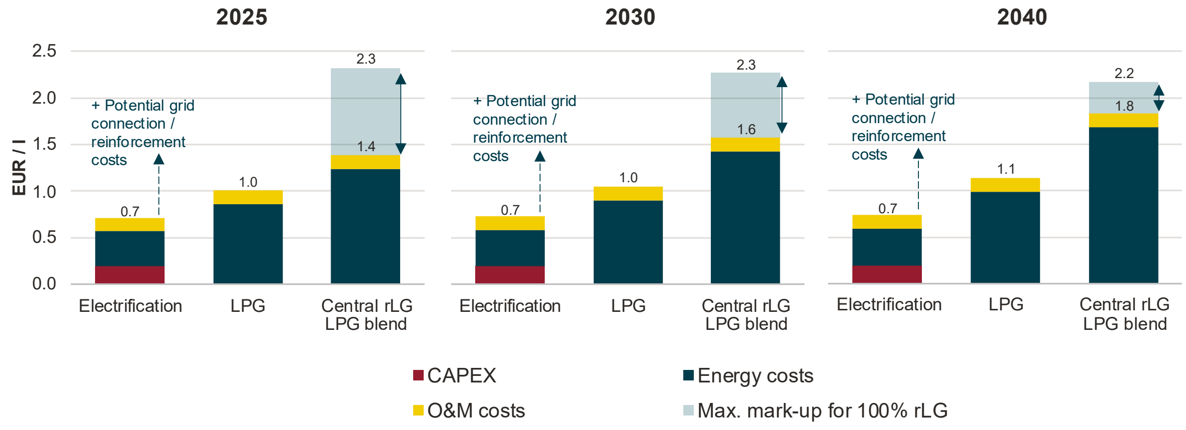
Distilleries require heat for distillation, typically supplied by steam boilers and/or direct-fired stills fuelled by natural gas, fuel oil, or LPG depending on the site. Electrification of heat demand can be achieved through high-temperature heat pumps. This requires substantial investments in new equipment and potentially an expansion of the grid connection, but it typically improves process efficiency significantly with heat pumps reaching coefficients of performance (COPs) of up to around 5.[41]

These efficiency gains translate into materially lower operating energy costs than combustion-based alternatives. As shown in Figure 17, the higher energy costs associated with rLG mean that electrification remains the lower-cost option on a total-cost basis, even after accounting for the upfront investment. However, this conclusion may be sensitive to site-specific electricity connection constraints: if distilleries need to fund a new or expanded grid connection, or contribute to wider grid reinforcement, the economics of electrification could weaken. This is particularly relevant in practice because industrial investment decisions are often guided by payback periods rather than lifetime total cost of ownership. In the specific case analysed, the heat pump investment has a discounted payback period of approximately 3.4 years relative to fossil LPG and 2.6 years relative to the rLG blend. Assuming a three-year payback requirement[42], the implied maximum justifiable CAPEX would be around EUR 0.9 million (vs. fossil LPG) or EUR 1.2 million (vs. the rLG blend). This highlights that the required investment of around EUR 1 million for heat pump hardware and installation can be a material barrier, particularly where additional expenditure is required for grid connection or reinforcement.

41 IEA Technology Collaboration Programme on Heat Pumping Technologies (HPT TCP) (n.d.), *Ahascragh Distillery Revolutionizes Whiskey Production with 100% Renewable Energy using High Temperature Heat Pumps installed by Astatine*. Available here. Accessed: March 2026.

42 Umweltbundesamt (2020), *Energy management systems in practice*. Available here. Accessed: March 2026

Figure 17 Cost comparison for distilleries



Source: Frontier Economics based on IEA HPT TCP (n.d.)
Note: Chart is based on energy price forecasts for Germany, results for other case study countries are comparable.

4.3.4 rLG can play a non-negligible role in the decarbonisation of industrial process heating to 2040

Overall, the strategic case for rLG in industrial heating is best framed as a high-value decarbonisation option in specific settings. In sectors and sites where LPG is already used, rLG can deliver significant value, particularly where it can be deployed quickly with limited disruption and minimal changes to existing equipment. That said, in the broader context of industrial decarbonisation, rLG is still likely to represent only a relatively small share of total industrial emissions abatement. rLG is most compelling for medium-to-high temperature applications, especially at off-grid or grid-constrained sites, and retrofit situations where electrification would require large capital investment or extended downtime. Conversely, in low-temperature processes where heat pumps provide strong efficiency gains (such as the distillery example), rLG is less likely to be the economic "first choice" unless site constraints materially limit electrification.

5 System perspective: Implications of electrification & the role of rLG

While the previous chapter assessed end-use economics, this chapter complements that analysis with a system perspective. We benchmark the system implications of rLG-based solutions against a full-electrification reference case. Rather than developing a fully-fledged energy system model, we use simplified, transparent calculations to illustrate orders of magnitude and to frame the discussion around system-relevant constraints. Results are indicative, not a forecast.

5.1 From individual economics to system impacts

The individual perspective is essential: households and firms decide based on private economics, including investment needs and operating costs. Yet system impacts can materially shape feasibility and total costs, especially where electrification amplifies winter peak load, increases the need for firm capacity during low renewable output, or triggers distribution grid reinforcement. These issues are most relevant in off-gas-grid settings constrained by timing, infrastructure, or cost.

5.2 Reference Case: What if today's LPG demand were fully electrified?

As a benchmark, we assume today's LPG demand in the relevant end-use segments is fully replaced by electricity. This translates an existing fuel demand into incremental electricity needs and highlights the associated system implications, based on explicit assumptions on technologies and conversion efficiencies.

5.2.1 Incremental annual electricity demand can reach more than 100 TWh per year

Based on the assumed electrification pathways, full substitution of today's LPG demand implies incremental annual electricity demand of **101 TWh/year** for the covered segments[43] which is around 4.1% of EU27+UK+NO+CH's electricity demand in 2024 as shown in Figure 18.

Meeting this additional demand would require additional electricity and, critically, sufficient capacity at the times it is needed. The system response will ultimately be shaped by how the power system balances higher utilisation of existing plants, the pace and mix of new generation investments, cross-border imports and exports, and the deployment of flexibility and network reinforcements. In the following, we use simple, indicative calculations to illustrate the order of magnitude implications of a full electrification of today's LPG demand.

43 We exclude refinery demand, as it would decline significantly under a full electrification scenario.

Figure 18 Incremental electricity demand due to LPG substitution

	Electrification Conversion Assumptions	LPG use (Mt/a)	Power use (TWh/a)
Residential	▪ 80% heat pumps (COP=3), ▪ 20% direct electrification (cooking etc.; factor 1)	4.53	27.2
Agriculture	▪ 50% direct electrification (e.g. drying/process heat), ▪ 50% heat pumps (COP=3)	0.84	7.2
Industry	▪ High-temperature process electrification (factor 1)	2.73	35.2
Transport	▪ Assuming same grid electricity c. 30% of LPG energy, based on tank/battery-to-wheel efficiency (ICE c.20–25% vs BEV c.75–85%)	5.38	20.8
Commercial	▪ 60% via heat pumps (COP=3) ▪ 40% via direct electrification (factor 1)	1.37	10.7

101 TWh/a

c. 4.4% of power demand in 2024 in EU27+3

Source: *Frontier Economics*

Note: *"Factor" denotes the electricity input required per unit of delivered service when replacing LPG in the respective end-use. For heat pumps, electricity demand is derived via the COP (useful heat output / electricity input). For road transport, electricity demand is estimated on a same-mileage basis using typical tank-/battery-to-wheel efficiencies (incl. charging losses). For industry, a factor of 1 is applied for all industrial electrification, representing a conservative 1:1 end-energy conversion (MJ electricity per MJ LPG) without assuming process-specific efficiency gains or losses.*

5.3 Peak demand and firm capacity: the system-critical constraint

From a system perspective, the most binding constraint is typically not annual electricity demand, but additional peak demand, particularly during winter conditions. Peak demand matters because it drives requirements for capacity that is reliably available in critical hours and can also be a driver of network reinforcement.

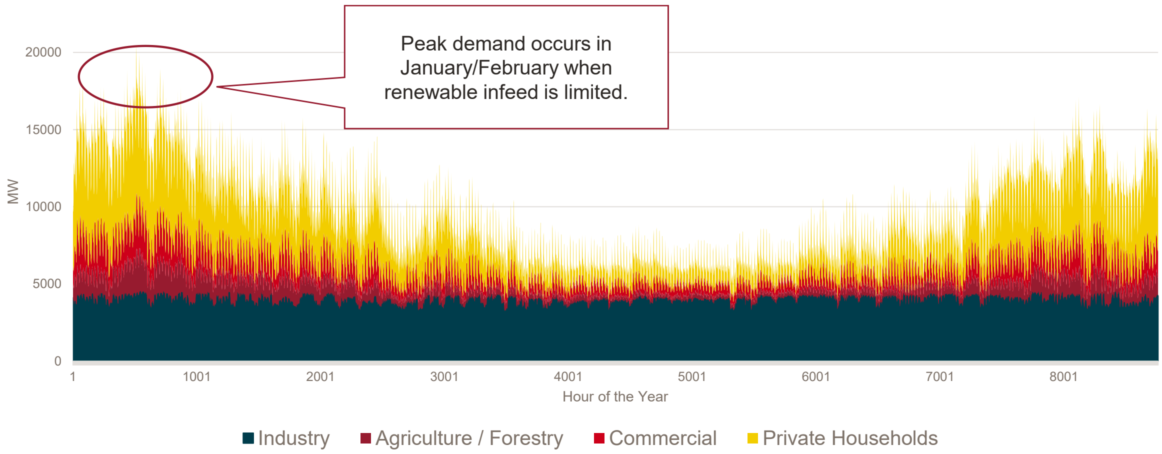
5.3.1 Incremental winter peak demand estimated at around 20 GW

Based on hourly load profiles from the Energy Transition Model (ETM) for 2030, electrifying current LPG use increases winter peak electricity demand by 20.5 GW (Figure 19). This corresponds to roughly 4.4% of EU27+UK+NO+CH's current peak demand[44]. We do not include the transport sector, as flexible charging can largely shift demand away from peak load periods. Importantly, the incremental peak load coincides with the system peak in January/February, when renewable infeed can be limited.[45]

44 ENTSO-E (2025), *Power Statistics*. Available here. Accessed: January 2026.

45 The hourly electricity demand in EU27 + UK + NO + CH is presented Chapter 3 in the technical annex.

Figure 19 Hourly electricity demand increase from LPG substitution by sector



Source: Frontier Economics, based on Argus Media (2025) and Energy Transition Model for TYNDP 2024 (EU-27 load profiles, 2030; Demand scenarios TYNDP 2024 After Public Consultation)

Note: Malta excluded (not interconnected with the European power grid)

5.3.2 Indicative CAPEX requirements for incremental peak demand

To translate the peak demand increase into a system implication, we estimate the additional *firm* capacity that would need to be available under winter peak conditions to maintain adequacy. Rather than deriving an optimised system outcome, we use three stylised scenarios to illustrate a plausible range of *dispatchable* capacity mixes and the associated CAPEX that could materialise in practice. Instead of relying on the single peak estimate of 20.5 GW derived from one representative weather year, we assess the additional firm capacity requirement across a range of 18–22 GW. This range reflects inter-annual weather variability and avoids over-reliance on a specific climatic realisation.

We focus on *firm capacity* options with high contribution to adequacy during scarcity hours. Weather-dependent renewables (wind/PV) have a limited ability to *reliably* cover winter scarcity hours, and short-duration batteries – even where they can discharge at high power – are constrained by how long they can sustain output and by the availability of charging energy in stress periods.[46] By way of example, multi-day winter scarcity events with low wind/PV output cannot be covered by intra-day shifting that batteries can provide.

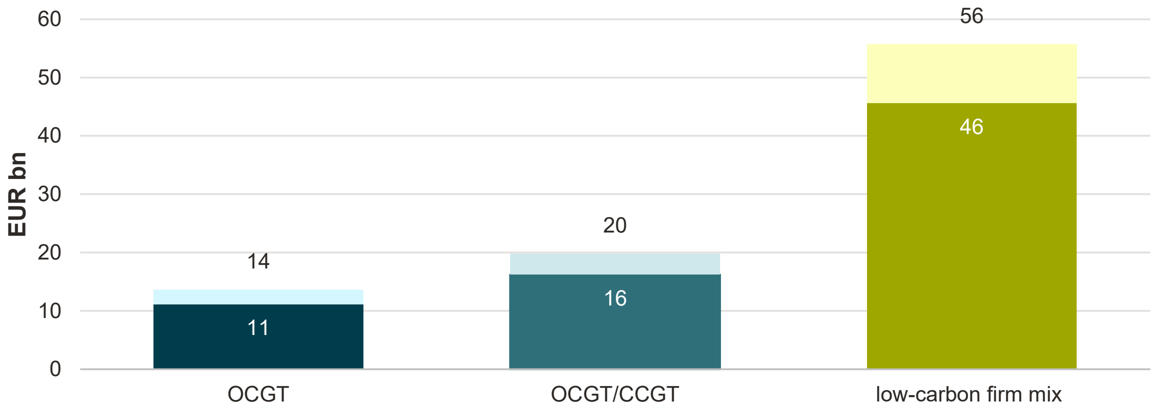
46 In adequacy assessments, technologies are translated into "reliably available capacity" during peak scarcity hours using a derating (or capacity credit) factor. For weather-dependent renewables, this factor is typically low because output can be low precisely when the system is tight. In Belgium's capacity market, the derating factors are around 10% for onshore wind, 11% for offshore wind, and 1% for solar PV. As an illustration, with a 10% capacity credit, achieving 1 GW of reliably available capacity would require around 10 GW of installed wind capacity (and with ~1% for solar PV, around 100 GW per 1 GW). In contrast, firm capacity such as thermal technologies often reach derating factor of 90% and higher.

We apply a consistent set of assumptions across all scenarios, using derating factors from the Belgian capacity market to translate installed MW into firm capacity at winter peak, and technology CAPEX assumptions from Fraunhofer (midpoint of the reported low/high ranges).[47]

- **Scenario 1 – OCGT-only (lowest-cost peakers)**: The full additional adequacy requirement is met with open-cycle gas turbines (OCGTs) – a relatively low-CAPEX peaking technology that can be built quickly and ramped flexibly, but is typically used only for a small number of tight peak hours. These units therefore have low utilisation and act as a pure capacity backstop. Covering an additional **18–22 GW** of peak demand with OCGTs would require approximately 97–118 OCGT backup power plants of 200 MW nominal capacity each. The total investment need would be **around EUR 11–14 billion** in upfront CAPEX.
- **Scenario 2 – 50/50 OCGT + CCGT (balanced peakers and more running hours)**: The additional adequacy requirement is met through a balanced portfolio of OCGTs and combined-cycle gas turbines (CCGTs), split evenly by firm capacity contribution. In this scenario, CCGTs play a central role: while they require higher upfront CAPEX than peaking units, they are more efficient and better suited to operate over a broader set of hours beyond the very tight peak periods, delivering lower operating costs. OCGTs complement this by providing flexible peaking cover for the very tightest hours. Covering the additional **18–22 GW** of peak demand under this 50/50 mix would require investment of around **EUR 16–20 billion** in upfront CAPEX.
- **Scenario 3 – low-carbon firm mix (⅓ H_2-ready turbines + ⅓ H_2-ready CCGT + ⅓ biogas/solid biomass):** The additional adequacy requirement is met through a diversified portfolio of dispatchable low-carbon firm capacity, split equally by firm capacity contribution across hydrogen-ready gas turbines, hydrogen-ready CCGTs, and biogas/solid biomass plants. This stylised pathway illustrates how peak adequacy could be maintained while aligning more closely with decarbonisation objectives, by relying on firm, dispatchable options rather than weather-dependent output or short-duration storage as primary adequacy providers. Covering an additional **18–22 GW** of peak demand under this low-carbon firm mix would require investment of around **EUR 46–56 billion** in upfront CAPEX.

[47] Elia Transmission Belgium (2019). CRM – Derating factors (Status update ADEMAR – CRM / TF CRM materials, 23 May 2019); Fraunhofer ISE (CAPEX ranges used for midpoint assumptions): Kost, C., Müller, P., Sepúlveda Schweiger, J., Fluri, V., & Thomsen, J. (2024). Levelized Cost of Electricity – Renewable Energy Technologies. Fraunhofer Institute for Solar Energy Systems ISE, July 2024.

Figure 20 Capacity Requirements to cover additional peak load



Source: Frontier Economics based on Fraunhofer (2024)[48]

Overall, the scenarios illustrate a wide but policy-relevant CAPEX range for maintaining adequacy under higher winter peak demand. At the lower end, the cheapest route to secure firm capacity is dominated by fossil gas peakers, which tend to run for only a limited number of hours but still require substantial upfront investment. Moving towards more efficient and lower-carbon dispatchable options increases CAPEX materially, reflecting the higher cost of technologies that can deliver firm capacity while supporting decarbonisation objectives. Across all cases, the implied investment volumes are not negligible: securing an additional **18–22 GW** of peak capacity is a system-scale challenge. By way of comparison, **20 GW** is close to twice the scale of capacity additions discussed in Germany's power plant strategy, and in practical terms it could translate into roughly 100 new peaking plants (around 97–118 units depending on sizing and availability assumptions) if delivered purely through peakers (e.g. OCGTs of around **200 MW** nameplate capacity each).

In practice, the system would not be built around a single technology choice. The scenarios above are therefore intended as stylised, indicative benchmarks to illustrate plausible ranges and orders of magnitude, rather than to predict the exact technology mix that would emerge.

It is important to note that electrifying current LPG demand represents only around 2% of total final energy demand. Extending electrification to larger fuel segments such as natural gas and heating oil would imply a significantly greater increase in electricity demand and associated system requirements. This suggests that low-carbon liquid and gaseous fuels can contribute to system flexibility by complementing electrification, particularly in managing the scale and timing of the transition.

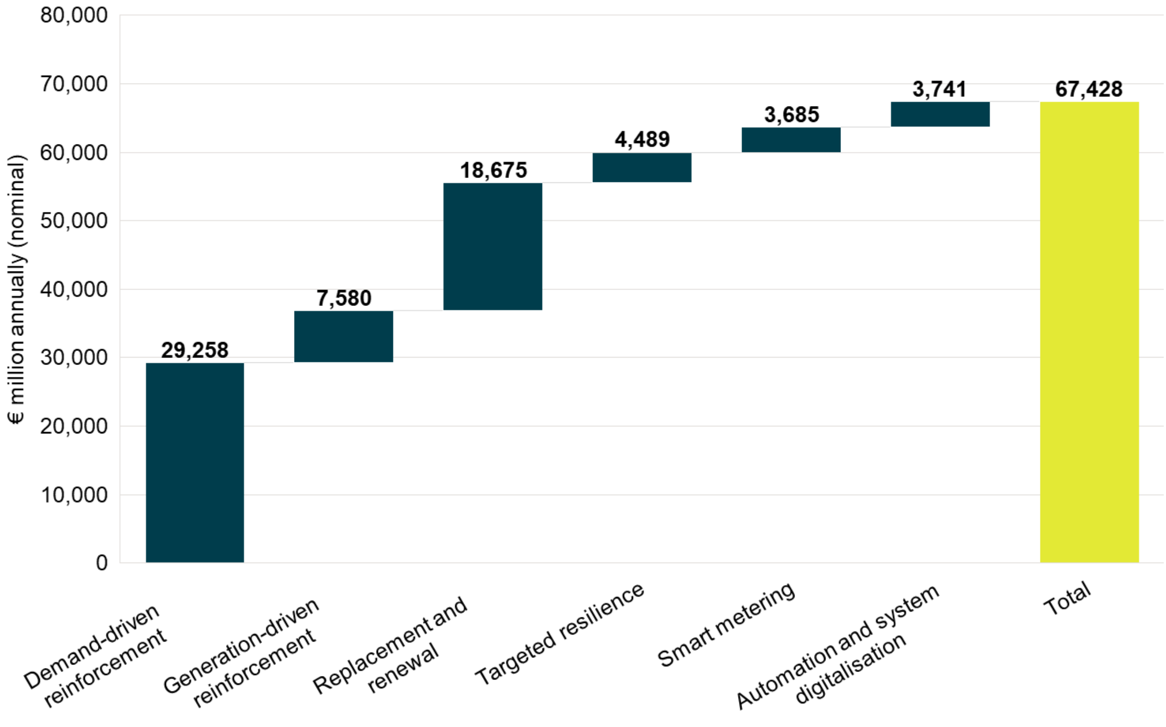
48 Kost, C., Müller, P., Sepúlveda Schweiger, J., Fluri, V., & Thomsen, J. (2024). Levelized Cost of Electricity – Renewable Energy Technologies. Fraunhofer Institute for Solar Energy Systems ISE, July 2024.

5.4 Grid constraints and reinforcement: why timing matters

Even where generation adequacy can be addressed, electrification also depends on grid capacity, especially at the distribution level. Reinforcement needs are highly local. They depend on network topology, existing headroom at transformers and feeders, and the characteristics of connected customers. In many regions, reinforcement requirements are rising due to a combination of drivers including heat pumps, EV charging, industrial electrification, and distributed generation.

The investment implications are substantial. Recent assessments point to a step change in required distribution grid investment across Europe, with average annual investment needs roughly doubling from around **EUR 33 bn/year (2019–2024)** to around **EUR 67 bn/year (2025–2050)**, frontloaded, and with cumulative distribution grid investment needs of around **EUR 402 bn until 2030**. The majority of investment needs sits at distribution level; transmission investment needs are estimated at roughly half of distribution needs.

Figure 21 Annual average distribution grid investment (EU27+NO, 2025-50)



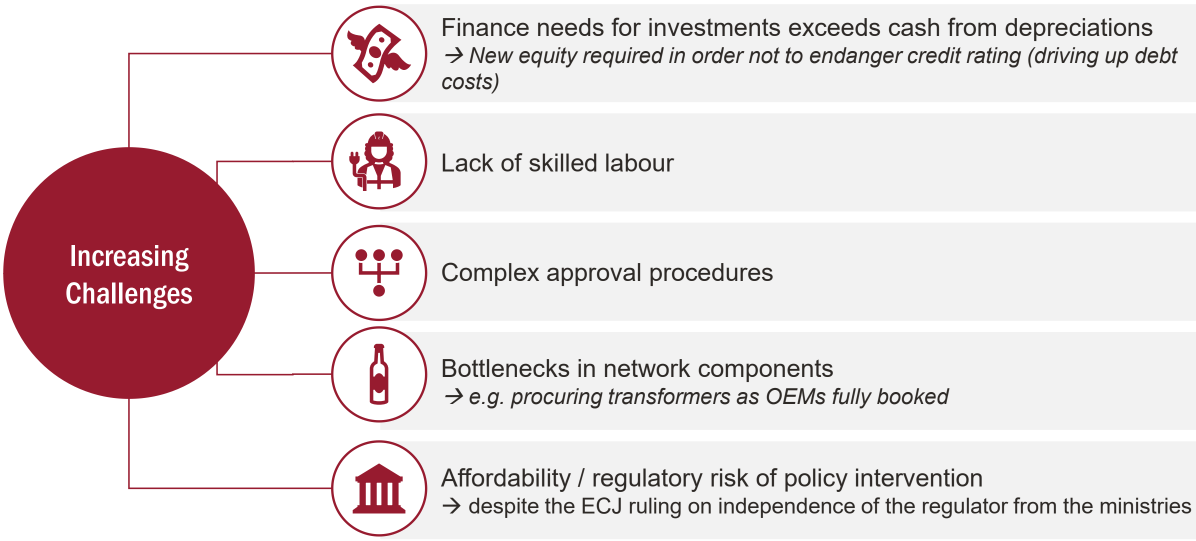
Source: Frontier Economics based on Eurelectric (2024), Distribution Grids Handbook. Available here. Accessed: January 2026; and Bruegel (2025), Upgrading Europe's Electricity Grid: It's About More Than Just Money. Available here. Accessed: January 2026.

Importantly, a material share of these investments is **demand-driven**: reinforcement is often triggered by rising peak loads from electrification at the point of use, e.g., clusters of heat pumps, EV charging, or new/expanded industrial connections – which can require upgrades to transformers, feeders and local substations.

In rural and low-density areas, these reinforcement costs can also be higher on a per-user or per-unit-of-capacity basis. Lower load density and the longer feeder lines required to connect dispersed consumers mean that additional network capacity often requires proportionally more infrastructure than in dense urban networks.

Where reinforcement is demand-driven and capacity headroom is limited, **timing becomes a binding constraint** for electrification. Delivery capacity is a constraint in its own right. DSOs face financing requirements because investment needs exceed depreciation-based cash flows, implying ongoing needs to raise new capital. At the same time, practical bottlenecks can slow reinforcement, including a shortage of skilled labour, complex approval procedures, and supply-chain constraints for key components such as transformers. As network tariffs rise to fund investments, affordability and regulatory risk can also become binding, with policy debates already emerging on how network costs should be allocated over time and across customer groups. Figure 22 provides an overview of common challenges limiting DSOs' ability to invest.

Figure 22 Challenges limiting DSOs' ability to invest



Source: Frontier Economics

In this context, rLG can serve as a *non-wire option*. By providing low-carbon heat and process energy without an immediate increase in local electricity peak loads, rLG can ease pressure on **demand-driven** distribution grid reinforcements and help sustain decarbonisation progress where electrification is constrained by local capacity and delivery timelines. The magnitude of this effect is inherently location-specific and depends on what drives upgrades in a given area. Where reinforcements are triggered mainly by rising peak demand from heat pumps, electrified industrial loads, or EV charging, the potential for rLG to relieve pressure in heating and process energy is likely larger. Where upgrades are driven primarily by the integration of distributed PV (e.g., rooftop installations), ageing assets, or other non-demand-related constraints, the impact of rLG on reinforcement needs is likely smaller.

5.4.1 Timing and delays: why an alternative pathway matters

Infrastructure timing is critical. In many remote and off-gas-grid locations, end users currently rely on fossil LPG and heating oil, and timely electrification is often constrained by local grid capacity, reinforcement lead times, and broader delivery bottlenecks. In these settings, the near-term alternative to rLG is often not full electrification but continued fossil fuel use. This matters for how options should be assessed: rLG can often be deployed with limited changes at the point of use and can deliver emissions reductions while electrification remains constrained. If rLG are not available, a material share of these near-term emissions reductions is at risk, as end users may have limited alternatives beyond continuing with incumbent fuels.

6 Climate perspective: Emissions impact of rLG

Building on the preceding chapters, three considerations frame the emissions assessment.

- First, demand for liquid gases is expected to persist in specific segments, most notably off-gas-grid heating and selected industrial process-heat uses, even as overall volumes decline.
- Second, the total-cost-of-ownership analysis identifies cases where high upfront CAPEX, retrofit requirements or site constraints make rLG a pragmatic option.
- Third, the system perspective highlights practical delivery constraints for electrification, including distribution grid reinforcement needs as well as winter peak and firm capacity requirements.

Taken together, this implies that while electrification, particularly via air-source heat pumps, is the preferred route in many settings, there are cases where the relevant near-term counterfactual is continued fossil fuel use. In these cases, rLG can deliver material decarbonisation versus today and offer complementary solutions to electrification through gradually increasing blends, allowing deeper reductions over time as supply scales towards fully renewable liquid gas. For industrial customers, where heat pumps are often not feasible and efficiency gains from electrification may be more limited, rLG can achieve emissions reductions closer to electrification outcomes while avoiding step-change investments and operational disruption.

It is important to note that rLG are not zero-emission fuels in life-cycle terms. Residual upstream emissions remain. In our assessment, we conservatively assume a life-cycle carbon intensity of 24 gCO_2e/MJ. This level ensures compliance with current EU regulatory thresholds – fuels above these thresholds would not qualify and could not be placed on the market as renewable fuels. Once these thresholds are met, they are recognised as renewable under the EU regulatory framework and can count towards the relevant targets. As discussed in the previous chapter, reported values for relevant EU pathways are typically below this level, meaning our assumption errs on the conservative side.

6.1 The use of blending rLG enables viable emission savings at household level

Household heating transitions will occur gradually rather than instantaneously. Installation capacity constraints, renovation cycles and heterogeneous household circumstances imply a staggered uptake over time, and not all households can finance the upfront investment required for a heat pump within a short timeframe.

To reflect this, we model the transition using **an illustrative housing district** containing 100 identical reference houses for each case study country (all assuming to currently use LPG heating), rather than analysing a single building. This framing makes it easier to show clearly what it means, for example, for 30% of households to switch technology, and how emissions evolve over time as upgrades are rolled out gradually.

In the following, the results for the German reference single-family house and the illustrative housing district are shown for illustration. The same methodology has been applied to Polish and Italian reference houses, with results with equivalent interpretation reported in Chapter 4 of the technical annex.

Benchmark: Household heating sticking to fossil LPG

As a conservative benchmark, we assume that all 100 houses in the district continue using fossil LPG for heating over 2025–2040.

For the German reference single-family house, cumulative emissions under this assumption amount to around:

- 95 tonnes of CO_2 per house over 2025–2040, and
- 9,500 tonnes of CO_2 across the 100-house district.

We then introduce two transition mechanisms to reflect realistic, gradual change.

Heat pump uptake (2% per year)

We assume a renovation and upgrade rate of 2% per year from 2025 onwards.[49] In a district of 100 houses, this means:

- 2 houses being upgraded each year.
- By 2040, 30 houses have switched to heat pumps.
- By 2040, 70 houses continue to remain on liquid gas.

The 30 switching houses are assumed to improve insulation and install an efficient heat pump with floor heating.[50] Importantly, the transition is staggered: houses upgraded later in the period continue to use liquid gas for several years before switching. Emissions reductions from heat pump uptake therefore build up gradually over time.

In the case of Germany, the heat pump uptake alone reduces cumulative emissions by around 1,300 tonnes of CO_2eq over 2025–2040 in the illustrative housing district, relative to the fossil benchmark.

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49 This is consistent with our assumption for the indicative demand estimation.

50 Unrenovated houses are assumed to rely on heat distribution via radiators (as shown for the relevant reference houses in Chapter 4. Newly renovated houses are assumed to have been upgraded to a better heat distribution via floor heating.

Heat pump uptake (2% per year) combined with rLG blending

In addition to heat pump uptake, we assume that houses still using liquid gas introduce renewable liquid gas (rLG) in line with our central blending assumption from 2025 onwards.

This applies to:

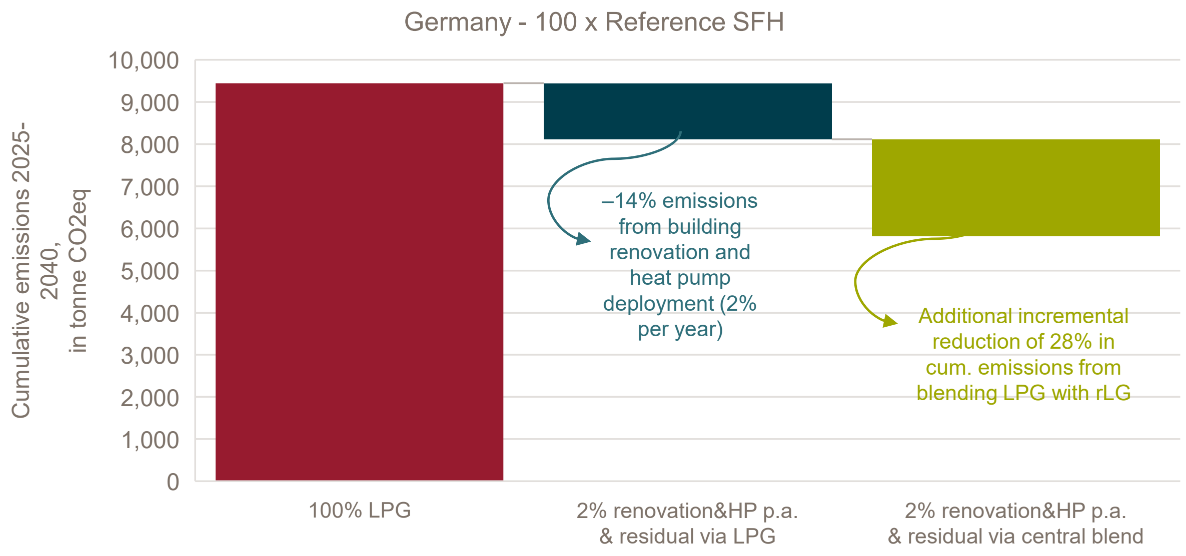
- The 70 houses that do not upgrade to heat pumps by 2040, and
- The 30 switching houses during the years before their upgrade

In other words, in each year, all houses that have not (yet) installed a heat pump benefit from increasing rLG shares of the central LPG rLG blend.[51]

In the case of Germany, combining gradual heat pump uptake with rLG blending increases cumulative savings 2025-2040 to around 3,600 tonnes of CO_2eq per house relative to the fossil benchmark at district level. This is an additional 2,300 tonnes per district compared with heat pump uptake alone.

Introducing rLG blending alongside realistic heat pump deployment therefore **increases cumulative emissions reductions 2025-2040 by a factor of three** compared with relying on heat pump uptake alone.

Figure 23 Cumulative emissions and emission reductions 2025-2040 for German illustrative housing district of 100 reference houses



[51] In this example of a German district, we have applied a simplified view of reality where we assume households either with HPs or an LPG boiler with a central rLG blend, however, in practice there could be cases where a single household could integrate a HP with a boiler that can run on rLG blend in a hybrid setting to combine the strengths of electrons and molecules.

Source: Frontier Economics

Note: In this assessment, renovated buildings are assumed to have improved insulation (i.e. lower energy demand) and to use an air-source heat pump (ASHP) with underfloor heating.

This illustrative housing district mirrors the assumed transition shares of a wider building stock while keeping the analysis transparent and intuitive. Results are calculated for stylised reference houses rather than national average buildings and should therefore not be interpreted as direct system-level projections.

6.2 Climate value of rLG depends not only on the volume of supply, but also on where it is deployed

Using the rLG supply potential set out in Chapter 2, we quantify the indicative emissions reductions that these volumes could deliver if used to displace incumbent fossil fuels in the covered end-use segments. We focus on the period to 2040, reflecting the near- to mid-term window in which infrastructure timing and delivery constraints are most relevant for real-world decarbonisation choices. For 2030, under the moderate case, we assume an intermediate level of supply by taking the average of the baseline and high scenarios. The analysis applies the supply trajectories from Chapter 2 and assumes a conservative uniform life-cycle carbon intensity of 24 gCO_2e/MJ for all rLG volumes.[52] This is consistent with compliance under current EU Renewable Energy Directive greenhouse gas saving thresholds. The assumed availability of sufficient low-carbon feedstocks at scale is supported by the Liquid Gas Europe outlook, which underpins the supply volumes used in this assessment.[53] Lifecycle emissions for incumbent fossil fuels are based on values reported by the European Commission's Joint Research Centre (JRC)[54], with assumed emission factors of 90.4 gCO_2e/MJ for heating oil, 73.2 gCO_2e/MJ for LPG and 74.7 gCO_2e/MJ for natural gas. For natural gas, emissions are based on LNG, reflecting that rLG is expected to replace more expensive and emissions-intensive imported gas rather than lower-emission pipeline supply.

Overall, the results show that the climate value of rLG depends not only on the volume of supply, but also on where it is deployed. Emissions savings per unit are materially higher when rLG displaces high-carbon fuels such as heating oil than when it displaces fossil LPG or natural gas. **This reinforces a practical prioritisation logic for the 2025–2040 period: where rLG supply remains limited, the highest near-term climate impact is achieved by**

52 The 24 gCO_2e/MJ assumption is conservative. As shown in Chapter 1, several production pathways can achieve materially lower life-cycle carbon intensities under favourable feedstock and process conditions. In addition, over time a growing share of supply is expected to come from CO_2- and H_2-based pathways, whose carbon intensity is likely to decline further as the power system decarbonises and renewable electricity becomes the dominant input. Applying a uniform 24 gCO_2e/MJ across all volumes therefore avoids overstating future emissions savings.

53 Liquid Gas Europe (2025), *Outlook* for rLG in Europe, March 2025. Available here. Accessed: March 2026, p. 22. The study concludes that for each assessed production pathway, the resulting fuel can meet the applicable RED greenhouse gas saving thresholds.

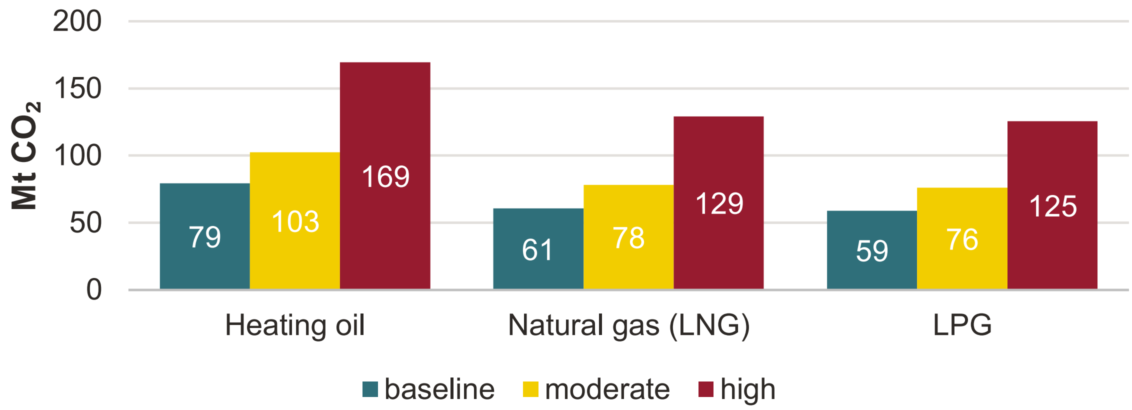
54 PRUSSI, M., YUGO, M., DE PRADA, L., PADELLA, M., EDWARDS, R. and LONZA, L., JEC Well-to-Tank report v5, Publications Office of the European Union, Luxembourg, 2020, https://data.europa.eu/doi/10.2760/959137, JRC119036.

targeting applications in which electrification is delayed or disproportionately costly and where the counterfactual is continued use of higher-carbon incumbent fuels.

Figure 24 summarises the resulting emissions savings across the three rLG supply trajectories. The results show that the overall emissions impact depends on two key factors: the volume of rLG made available and the incumbent fossil fuel it substitutes. Higher supply volumes translate into higher cumulative savings, while substituting higher-carbon fuels delivers materially larger emissions reductions per unit of rLG.

Under the moderate supply trajectory, **cumulative emissions** savings to 2040 reach around **76** $MtCO_2e$ in the fossil LPG displacement case. Savings are substantially higher if rLG is displacing higher-carbon fuels such as heating oil.

Figure 24 Emission savings from rLG replacing incumbent fossil fuel until 2040



Source: Frontier Economics

Note: Emission factors are based on values reported by the European Commission's JEC Well-to-Tank report v5. The values used are 90.4 gCO_2e/MJ for heating oil, 73.2 gCO_2e/MJ for LPG and 74.7 gCO_2e/MJ for natural gas. For natural gas, emissions are based on LNG supply.

Finally, it is important to note that the emissions impacts shown here are illustrative. The examples presented are stylised and intended to indicate the potential order of magnitude of emissions reductions that rLG could deliver if deployed at scale. They do not represent a projection of actual fuel substitution patterns. Determining how much rLG will replace specific fuels in practice requires system-level modelling that accounts for costs, infrastructure constraints and competing decarbonisation options, which is beyond the scope of this analysis. In practice, fuel substitution will be shaped by relative prices and carbon intensity under prevailing market conditions. Where effective carbon pricing mechanisms – including the EU ETS and, prospectively, EU ETS 2 – are in place, substitution would be expected to occur first in the most carbon-intensive segments, thereby maximising the climate benefit of available rLG supply.

7 Conclusions: The value of rLG

This White Paper assesses renewable liquid gases (rLG) as a complementary decarbonisation option in specific rural and off-gas-grid and hard-to-electrify settings. Electrification and network-based gases remain central pillars of Europe's energy transition. However, in segments where infrastructure timing, capital intensity or technical feasibility constrain immediate electrification, rLG can contribute to emissions reduction without requiring structural change at the point of use.

Three overarching insights emerge:

- First, economic attractiveness depends on context. At end-use level, rLG are most competitive in applications where electrification requires significant upfront investment, building retrofit or plant modification. In selected residential and medium- to high-temperature industrial cases, rLG provide a lower-risk decarbonisation pathway. In low-temperature processes with strong heat pump efficiency gains, electrification typically remains the lower-cost option.
- Second, system constraints shape what is deliverable. Large-scale electrification of current liquid gas uses increases winter peak demand and firm capacity requirements and may trigger substantial investment in generation and distribution infrastructure. Even before accounting for network needs, maintaining generation adequacy under full electrification of today's LPG demand would require at least EUR 11–14 bn of CAPEX. In delivery-constrained locations, rLG can reduce pressure on peak loads and grid reinforcement by limiting additional electrified demand. Their system value is therefore greatest where infrastructure expansion is slow, or capacity headroom is limited.
- Third, climate impact depends on real-world counterfactuals and market conditions. In the case studies examined in this White Paper, electrification is often not the relevant near-term counterfactual due to infrastructure timing, capital constraints or technical limitations. The practical alternative in many of these settings is continued use of fossil fuels. Where rLG displace such higher-carbon fuels, they deliver additional emissions reductions that would not otherwise occur. In the household sector in particular, introducing rLG blending alongside realistic heat pump deployment increases cumulative emissions reductions 2025-2040 by a factor of three compared with relying on heat pump uptake alone. Under functioning market signals – in particular through carbon pricing mechanisms such as the EU ETS and, prospectively, EU ETS 2 – substitution will be driven by relative carbon intensity and cost. In such a framework, the most carbon-intensive fuels are replaced first, allowing rLG deployment to concentrate where the climate benefit is greatest and ensuring that overall emissions reductions are maximised.

8 Policy implications: Challenges & recommendations

8.1 Key barriers in the current policy framework

rLG can support decarbonisation in specific off-gas-grid settings where electrification and network-based gases (notably biomethane or hydrogen) are not yet available, not technically suitable, or not cost-effective. However, the current EU policy framework does not yet provide the clarity and investment conditions required for a rapid and efficient market ramp-up. The most material barriers are as follows.

- First, **price signals and cost pass-through are not always aligned with decarbonisation outcomes.** In practice, the combined effect of carbon pricing, energy taxation, levies and retail price regulation can be difficult for end users and investors to interpret. Where signals are weak, unstable, or inconsistent, switching decisions are slowed and innovative production pathways take longer to develop. This is particularly relevant for off-gas-grid and rural consumers and for smaller industrial sites with limited ability to absorb high upfront investment.
- Second, there is **not yet a consistently level playing field across decarbonisation options**. Even where policy intent is technology-neutral, design choices can create implicit advantages or disadvantages through crediting rules, eligibility criteria, administrative requirements, Member State implementation, and technology-specific support. In practice, for example electrification often benefits from targeted measures (e.g. heat pump support, electricity price reliefs and industrial programmes). While these may be justified from a system perspective, alternative low-carbon options can face a structural disadvantage if comparable outcomes are not treated consistently. Without consistent treatment, investment may not flow to the most cost-effective solution mix.
- Third, **policy discussions can underweight system-level impacts.** Single-technology comparisons often focus on end-user efficiency or upfront costs, but miss implications for peak electricity demand, grid reinforcement, backup capacity, and the timing of infrastructure delivery. The EU is increasingly addressing grid constraints and promoting flexibility and non-wire alternatives; in this context, **rLG** can be seen as a potential **non-wire option** by enabling decarbonisation without immediately adding to local electricity peaks or requiring point of use grid upgrades. If these system effects are not considered, policy can unintentionally steer towards higher overall system costs.
- Fourth, **administrative and regulatory friction raises transaction costs** for emerging value chains such as rLG. Existing certification and traceability rules are not designed to take into account the specifics of liquid gas supply chains and can increase compliance costs and slow down scaling, particularly if applied inconsistently across Member States.

8.2 Recommended policy actions

The policy objective should be to enable rLG where they are a cost-effective complement, without creating open-ended subsidy regimes or technology-specific carve-outs. Targeted market-oriented actions can materially improve investment conditions while remaining consistent with EU decarbonisation priorities.

- **Strengthen investment-grade price signals while keeping policy coherent and predictable:** A robust and predictable carbon price is essential for investment. Policymakers should ensure coherence between EU ETS, energy taxation and levies, and decarbonisation objectives so that incentives are transparent and investable. The timely introduction of EU ETS 2 is critical to reduce uncertainty and support earlier switching and production investment. Where a fully aligned price framework is not (yet) politically feasible and complementary demand-side instruments are considered, these should be technology-neutral and recognise comparable decarbonisation outcomes across energy carriers. Technology-open approaches, such as the revised German green gas quota in the buildings sector (*Gebäudemodernisierungsgesetz*), illustrate how rLG can be incorporated alongside other options delivering equivalent emissions reductions.
- **Provide regulatory clarity and consistent recognition across relevant frameworks**: Ensure a stable and coherent basis for rLG deployment by improving consistency across EU legislation and implementation guidance, in particular for heating and industry applications. The goal is clarity on eligibility, accounting and compliance treatment so that market participants can plan investments and supply chains with confidence.
- **Secure an outcome-based level playing field across decarbonisation options:** Align rules so that comparable emissions performance is treated comparably, regardless of the carrier or technology. This requires taking into account not only targets, crediting and eligibility rules, but also technology-specific support schemes and the way taxes, levies and price reliefs shape end-user economics, for example heat pump subsidies or measures that reduce effective electricity prices for industry.
- **Embed a systems-cost lens in policy assessment and decision-making:** Future energy system policy evaluations including impact assessments and systems-modelling should reflect impacts of providing firm power generation, transmission and distribution capability to serve rural and off-gas-grid areas. This includes the potential of rLG to reduce or defer peak-driven grid upgrades, backup capacity needs and infrastructure bottlenecks, helping target rLG to use-cases where they deliver the highest system value while supporting decarbonisation goals.
- **Reduce avoidable regulatory friction and transaction costs in early market ramp-up:** Streamline and, where feasible, harmonise administrative processes such as certification and traceability management to reduce unnecessary overhead and take into account unique aspects of liquid gas supply chains while maintaining environmental integrity. The objective is to lower transaction costs, improve transparency, and enable scalable cross-border value chains.