STUDY

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The Revision of the Third Energy Package for Gas

Policy Department for Economic, Scientific and Quality of Life Policies
Directorate-General for Internal Policies
Authors: Laura HEIDECKE et al., Ecorys
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EN

The Revision of the Third Energy Package for Gas

Abstract

This study takes a closer look at the proposed revision of the Third Energy Package for Gas. The report reflects on how the revision and the foreseen unbundling rules affect the transition to a hydrogen-based gas economy. Apart from the long-term view and in consideration of the current energy crisis, the report also reflects on short-term options to ensure stable prices and security of supply through new EU gas interconnectors, liquefied natural gas imports and underground gas storage. The findings highlight the challenge of guaranteeing security of supply through new investments in natural gas infrastructure while simultaneously developing a hydrogen infrastructure, which is currently not pulled by market demand but driven by policy objectives for decarbonisation and increased autonomy. Achieving this will require both public support and risk-taking from involved actors in the hydrogen market.

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AUTHORS

Laura HEIDECKE, Senior Consultant, Ecorys
Irina KUSTOVA, Research Fellow, CEPS
Michael FLICKENSCHILD, Senior Consultant, Ecorys
Yoeri DIJKHOF, Consultant, Ecorys
Iris LARMI, Junior Consultant, Ecorys
Harry VAN TIL, Principal Consultant, Ecorys
Menno VAN BENTHEM, Senior Consultant, Ecorys
Nga NGUYEN, Senior Consultant Ecorys

ADMINISTRATORS RESPONSIBLE

Matteo CIUCCI

EDITORIAL ASSISTANTS

Irene VERNACOTOLA

LINGUISTIC VERSIONS

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ABOUT THE EDITOR

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To contact the Policy Department or to subscribe for email alert updates, please write to:
Policy Department for Economic, Scientific and Quality of Life Policies
European Parliament
L-2929 - Luxembourg
Email: Poldep-Economy-Science@ep.europa.eu

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LIST OF ABBREVIATIONS

ACER	European Union Agency for the Cooperation of Energy Regulators
CEER	Council of European Energy Regulators
CEF	Connecting Europe Facility
DSO	Distribution System Operator
EHB	European Hydrogen Backbone
EIB	European Investment Bank
EU	European Union
ETS	Emission Trading System
FSRU	Floating storage and regasification units
GHG	Greenhouse Gas
GIE	Gas Infrastructure Europe
IPCEI	Important Projects of Common European Interest
ISO	Independent System Operator
ITO	Independent Transmission System Operator
LNG	Liquefied Natural Gas
NRA	National Regulatory Authorities
NRRP	National Recovery and Resilience Plan
OU	Ownership Unbundling
PCI	Project of Common Interest
RES	Renewable energy source
RRF	Recovery and Resilience Facility
TPA	Third-Party Access

TSO	Transmission System Operator
TTF	Title Transfer Facility
UGS	Underground Gas Storage
UIOLI	Use It Or Lose It
VIU	Vertically Integrated Undertaking
YoY	Year-on-Year

EXECUTIVE SUMMARY

This study takes a closer look at the proposed revision of the Third Energy Package for Gas, the 'Hydrogen and decarbonised gas market package'. In particular, in light of the EU's **triple challenge of ensuring the security of gas supply, securing affordability and accelerating decarbonisation**, it looks at the role of the revised package including the foreseen unbundling rules in facilitating a transition to a hydrogen-based gas economy. Beyond this, it also discusses more short-term options to ensure stable prices and access to natural gas through new EU gas interconnectors, liquefied natural gas (LNG) imports and underground gas storage.

We find that the Third Energy Package for Gas has been successful when it comes to liberalising the gas market, increasing competition and improving the security of supply. It also provided sufficient flexibility for emerging markets, which in turn however led to different implementations of unbundling rules across the Member States, though a trend towards an increasing level of unbundling, i.e. ownership unbundling, can be observed.

The **'Hydrogen and decarbonised gas market package' is an important step to providing a regulatory framework that also addresses the decarbonisation of the gas market**. Despite this, there is not yet a hydrogen market and its development is currently more driven by policy objectives than market demand while existing hydrogen infrastructure is mostly localised and operated by private entities on industrial sites. Regarding the nascent status of the hydrogen market, stakeholders representing gas undertakings have been critical of the proposed cut-off date of 31 December 2030 after which exceptions covering third-party access (TPA), unbundling and tariff structures will be removed. They are particularly worried that electricity and gas transmission system operators (TSOs) currently operating as Independent Transmission System operators (ITO) would be barred from investing in hydrogen infrastructure after 2030. This **could reduce the willingness of such gas operators to make capital-intensive investments in new infrastructure or for repurposing existing infrastructure** that would be needed to support the development of the market.

Though the European Commission expressed a preference for the implementation of the OU model, convincing evidence that supports its preference is thin at best. Moreover, there is no clear evidence indicating that the gas market or the hydrogen market will function better without the ITO model. Exclusion will have an impact on current gas network operators and will result in costs for ITO operated network operators. Therefore, **we consider regulatory alignment with the existing gas market to be preferential**.

Since currently hydrogen is mainly produced and consumed in industrial clusters, investments are needed to establish a hydrogen infrastructure that can service future needs. Following the Russian invasion of Ukraine, the REPowerEU Plan outlined **the ambition to produce 10 million tonnes of renewable hydrogen domestically and import another 10 million by 2030**. To achieve such amounts a hydrogen network would need to be deployed that connects ports of import and production clusters with industrial clusters in need of hydrogen.

A European Hydrogen Backbone initiative proposed by European energy infrastructure operators could serve such needs. It would be deployed through the repurposing of natural gas infrastructure and the construction of new infrastructure. However, the initiative **represents not a thorough network planning exercise but is a scenario developed by energy infrastructure operators** to showcase what would be achievable by 2030 and 2040 and based on that the estimated investment needs. Currently, there is still a lot of uncertainty and it is difficult to predict when and where demand and production will develop apart from a few industrial clusters that already produce hydrogen or are likely to switch to hydrogen in their decarbonisation. Nevertheless, proponents of the hydrogen backbone point out that some risk-taking is needed as, currently, hydrogen is for many users simply not an affordable option due to the lack of infrastructure, raising the question of what should come first: infrastructure or demand.

Repurposing existing gas networks is generally seen to be the most cost-efficient option for the development of a hydrogen network since the supply and demand of hydrogen will partially follow the current supply and demand for natural gas. However, **the future hydrogen network will not be as extensive as the current gas infrastructure**. Moreover, the use of natural gas networks is expected to only gradually decrease and likely the need for gas-only networks will remain, which indicates that not all the existing gas infrastructure can be converted to hydrogen. Construction of new hydrogen infrastructure will therefore be necessary. The repurposing of LNG terminals to import hydrogen is also under discussion. However, compared to pipelines, their conversion is seen as a big technical challenge.

The **required financing of such investment cannot come alone from revenues from user tariffs** as these will be insufficient during the initial years of the transition or would put too high costs on the initial users. One option in the proposed 'Hydrogen and Decarbonised Gas Market Package' is to facilitate limited cross-subsidies between the gas and hydrogen sectors. It could, however, lead to households financing the decarbonisation of industry, since the end users of hydrogen differ from those of natural gas. In addition, public funding is being made available through the Important Projects of Common European Interest (IPCEI), the Projects of Common Interest (PCI) under the TEN-E Regulation, the Recovery and Resilience Facility (RRF) and other sources. Beyond these, guarantees for hydrogen production will also be provided through the newly proposed European Hydrogen Bank. These public funds will need to be complemented by private financing, which will require some risk-taking by companies. In addition to the required funding, the **speed of the transition will also depend on permitting and regulatory processes** with permitting being seen as the biggest factor slowing down large-scale infrastructure processes. In this regard, the recent proposal for a one-year temporary Council Regulation laying down a **framework to accelerate the deployment of renewable energy** is a good step in accelerating permitting. Finally, the timeframe in which the current gas infrastructure can be repurposed to hydrogen is a factor of uncertainty as it also depends on the availability of parallel infrastructure in case of parallel demand for natural gas and hydrogen.

More immediately, Russia's invasion of Ukraine has also led to a process of **restructuring the EU's gas imports with liquefied natural gas (LNG) becoming a key supply source**. However, despite substantial progress in past decades to increase gas interconnectivity (especially in Central and South-East Europe and the Baltics) additional investments (EUR 10 billion by 2030 according to REPowerEU) into new gas infrastructure are needed to address several bottlenecks in the EU. This includes investments into new LNG terminals and floating storage and regasification units (FSRUs) as well as pipeline interconnectors. The key one is located in **North-West Europe**, between Belgium, France and Germany. With certain regulatory and infrastructural adjustments, supplies can be increased from French, Belgian and Dutch LNG terminals into Germany. The **Iberian Peninsula** is another bottleneck as its rich LNG capacity cannot be used to source from other Member States due to infrastructural constraints with France.

With LNG becoming a key supply source, some **Member States streamlined the expansion of LNG terminals and new FSRUs**, often in record time, although permitting has remained a sensitive issue leading to slow upgrades in recent years. From the supply side, **the volatility of LNG imports into the EU and the high price responsiveness of LNG spot and short-term cargoes** have added to the relative irregularity of LNG imports into the EU in recent years.

Another key component in providing system balance is **gas storage**. Low levels of storage filling in 2021 and Russia's invasion of Ukraine facilitated a fast-track adoption of the Gas Storage Regulation that provided a minimum of 80% gas storage level obligation for the EU average by 1 November 2022, rising to 90% for the following years, and an obligatory certification of Storage System Operators (SSOs).

Considering the above-summarised issues, it is key for EU policymakers to **consider how to ensure an affordable and secure gas supply while not losing track of decarbonisation**. For this, exchange with regulators, energy and gas undertakings and users (industry and households) is required as well as cooperation between the Member States to find optimal solutions. In chapter 5 of this report, we discuss particular policy challenges and make recommendations for:

- regulation of the gas market including unbundling rules;
- short-term to medium-term view: Ensuring the security of gas supply; and
- long-term view: Hydrogen investments and readiness.

INTRODUCTION

Decarbonising Europe's energy sector has been a key policy priority. This only increased in importance with Russia's invasion of Ukraine in February 2022. Moving away from natural gas to decarbonised gases such as hydrogen is central both for becoming environmentally sustainable and for becoming more energy independent to ensure autonomy and price stability. In light of these pressing circumstances, the European Parliament Committee on Industry, Research and Energy (ITRE) commissioned Ecorys together with the Centre for European Policy Studies (CEPS) to conduct a study on "The Revision of the Third Energy Package for Gas".

Aim and methodology

The study "The Revision of the Third Energy Package for gas" aims to provide an independent overview of the proposal for a revised gas framework – the Hydrogen and decarbonised gas market package – in light of the current energy crisis and the new geopolitical context with the Russian invasion of Ukraine. In particular, the study covers the following aspects:

- **Chapter 1** provides an overview of the issues at stake, namely sustainability, affordability and autonomy, followed by a presentation on the current regulatory framework for gas and the proposed changes;
- **Chapter 2** describes the unbundling rules and their implementation in the Member States under the Third Energy Package for Gas. Looking beyond this, it also discusses the opportunities and barriers to the uptake of hydrogen infrastructure under the Hydrogen and decarbonised gas market package;
- **Chapter 3** dives deeper into the topic of hydrogen, looking in particular at the status quo and scenarios for the uptake of hydrogen in the EU as well as options for financing and deploying hydrogen infrastructure;
- **Chapter 4** focuses on the security of the energy supply looking in particular at the weaknesses and risks uncovered by the Russian aggression and how these affected patterns of flows of natural gas. It also discusses gas interconnectors, LNG terminals and storage options to address bottlenecks, highlighting, in particular, the following regions: the Iberian Peninsula, North-West Europe, the Baltic Sea region, and South-East Europe; and
- **Chapter 5** summarises the key findings across the previous chapters and provides policy recommendations for the consideration of the European Parliament.

The study used a combination of desk research, interviews with stakeholders and an expert workshop and follows the definitions of the European Commission for renewable hydrogen[1] and low-carbon gases[2].

[1] Renewable hydrogen is the term used by the European Commission and refers to hydrogen produced from renewable energy sources (RES). The exact definition of renewability of hydrogen is currently under debate.

[2] Low-carbon gases are low-carbon fuels that are in gaseous form, including low-carbon hydrogen. An exact definition by the Commission is lacking, and again, the definition is under political discussion.

1. THE EUROPEAN GAS MARKET AND ITS TRANSITION TO NEW AND RENEWABLE GASES

KEY FINDINGS

The EU heavily relies on gas for its industry, heating and electricity generation. To satisfy this high demand, the EU is highly dependent on imports with an **import dependency of nearly 84%** in 2021 with most imports coming from Russia (34%), Norway (24%) and Algeria (7%).

The EU faces a **triple challenge, to ensure the security of gas supply and, at the same time, to secure affordability and accelerate the decarbonisation of the gas sector**. This challenge has been heightened with the invasion of Ukraine by Russian forces and ensuing EU sanctions against Russia. This already had the effect of restructuring the EU's gas import portfolio away from Russian pipeline imports to LNG imports. Consequently, the green transition of the European gas market and the move towards new and renewable gases is not only a challenging undertaking but also an opportunity to:

- **Ensure environmental sustainability** of the European gas sector;
- **Enable competitiveness and affordability** by creating a more stable supply of gas;
- **Secure the autonomy of the EU** from gas imports and reduce dependencies on individual third countries.

Since 2009, the EU regulatory framework for gas has been governed by the **Third Energy Package** and its twin gas regulation and directive on conditions for access to the natural gas transmission networks as well as on common rules for the internal market. This regulatory framework has been found successful when it comes to liberalising the gas market and increasing competition. However, particular shortcomings were also identified, the main one relating to its lack of support for decarbonising the gas market and supporting the transition to renewable gases such as hydrogen.

To address this, the proposed revision of the Third Energy Package for gas in form of the '**Hydrogen and decarbonised gas market package'** proposes several key changes to the EU gas market. In particular, it aims to address barriers such as the lack of a cross-border hydrogen infrastructure, of a competitive hydrogen market and of network planning by introducing a regulatory framework modelled after the one for the natural gas market, which will be implemented through the proposed revised 'Gas Directive' and 'Gas Regulation'. This is complemented by other regulatory actions, such as the revision of the TEN-E regulation, the proposed revision of the gas security regulation, the new regulation on gas storage, and the 'Save gas for a safe winter' package.

1.1. Transitioning to renewable gases – a challenge and opportunity

The current political context urges the European Union (EU) to assess the best available options to source extra gas volumes and to ensure the interconnectedness of its gas infrastructure, securing at the same time a decarbonisation path of its gas sector by replacing natural gas with renewable alternatives. Measures targeted at Russia have been the focus of EU policy-making since Russia invaded Ukraine in February 2022, while the uptake of renewable gases is seen as a long-term solution. Short-term solutions such as increasing LNG imports, reducing the demand for natural gas and increasing power production from coal-powered plants have already led to a reduction of the EU's dependence on pipeline gas imports from Russia. Compared with 2021, the share of Russian pipeline imports into the EU and UK gas portfolio dropped from 30.5% to 20% in the first half of 2022 as estimated by ACER and CEER (2022)[3]. The interruption of Russian gas imports has however also come with soaring gas prices.

This has led to **a triple challenge: to ensure the security of the gas supply, accelerate the decarbonisation pathway in the gas sector, and secure affordability**. The proposed 'Hydrogen and decarbonised gas market package'[4] presented by the European Commission in December 2021 had been developed before the current energy price crisis and the geopolitical turmoil. This raises the question of whether the current legislative proposal might not offer an up-to-date solution to this triple challenge. The EU policy framework needs to find suitable pathways to ensure reforms of the EU internal gas market that **reinforce the three pillars of the EU energy policy: its environmental sustainability, competitiveness and security of supply**.

1.1.1. Sustainability and decarbonising the European gas sector

The European Green Deal[5] announced in late 2019 in the Commission's Communication provided some of the most ambitious policy goals that will restructure the European economy towards decarbonisation, thus reaching net-zero greenhouse gas (GHG) emissions by 2050. The climate neutrality objective stipulated in the Green Deal was introduced into legislation further by the European Climate Law[6] that defined the intermediate target of reducing net GHG emissions by at least 55% by 2030, compared to 1990 levels. Reaching the objectives of the Green Deal would require a substantial increase in the share of low-carbon electricity, improved energy efficiency, and decarbonisation of the so-called 'hard-to-abate' sectors, among others.

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3 It is worth noting that in the first half of 2022 LNG imports from Russia into the EU and UK grew from 3.9% to 5% in the total gas portfolio.

4 The 'Hydrogen and decarbonised gas market package' includes the proposal for a recast Directive on gas markets and hydrogen (COM(2021) 803 final) and the proposal for a recast Regulation on gas markets and hydrogen (COM(2021) 804 final).

5 European Commission, 2019b, *'The European Green Deal'*, COM(2019) 640 final, 11.12.2019. Available at: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.

6 Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law').

Decarbonisation of the gas sector has been a constant priority for the EU. A steady phase-out of natural gas by 2050 has been envisaged in all scenarios of the European Commission's Long-Term Energy Strategy 'A Clean Planet for All' (2018) and further in the impact assessment of the Fit for 55 package[7]. **Nevertheless, gases will still play a small role in 2050**. While natural gas is reduced to a fraction of its current demand in the European Commission scenarios for 2050. It will be substituted by new renewable and low-carbon fuels, mainly of gaseous form. In comparison, the 2022 World Energy Outlook of the International Energy Agency (IEA) foresees a reduction of natural gas in the global energy mix from 23% in 2021 to 15% in 2050 in their 'Announced Pledges Scenario'. Partially, this is also due to increased demand for natural gas to produce low-emission hydrogen. According to this scenario, natural gas demand would persist also in the EU[8]. The IEA report highlights how investments fall short of what would be needed to fulfil the existing pledges. However, it also highlights that the war in Ukraine and soaring gas prices have led to the acceleration of some projects in advanced economies to replace natural gas, while in developing economies it has slowed the switching from coal to natural gas[9].

Gas interconnectors and Liquefied Natural Gas (LNG) terminals had been largely viewed as increasingly stranded assets. In its decision of late 2019, the European Investment Bank stopped financing fossil fuel projects as of 2022[10]. Also in line with the climate ambitions, the revised Trans-European Networks for Energy (TEN-E) Regulation excluded most new gas projects from the infrastructure categories eligible for financial support[11]. Contrarily, hydrogen infrastructure projects received a special focus in the TEN-E Regulation together with offshore electricity grids and smart grids. Despite this, the EU taxonomy for sustainable activities includes natural gas as a transitional activity contributing to climate change mitigation. Moreover, following the Russian invasion of Ukraine, the REPowerEU Plan foresees additional investments into gas infrastructure and LNG terminals[12] with the prospect of making these ready also for renewable gases. Repurposing of gas infrastructure was framed by various stakeholders[13] as a key option given the estimations of gas demand shrinking in the future.

In parallel, since the adoption of the European Green Deal and the phase-out of support for natural gas, several initiatives have been taken to support alternative gases such as hydrogen and biomethane with the objective to decarbonise the gas industry.

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7 European Commission, 2020c, *Commission Staff Working Document, Impact Assessment. Accompanying the document Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions. Stepping up Europe's 2030 climate ambition Investing in a climate-neutral future for the benefit of our people*. SWD/2020/176 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020SC0176.

8 The World Energy Outlook 2022 predicts natural gas demand to drop to 15% ('Announced Pledges Scenario', APS) or 20% ('Stated Policies Scenario', STEPS) of global energy demand. For the EU, the model foresees a reduction from 421 billion cubic metres of natural gas equivalent (bcme) in 2021 to 45 bcme for the APS and 235 bcme for the STEPS scenarios in 2050. See page 372: IEA (2022) World Energy Outlook 2022.

9 In the World Energy Outlook 2022 natural gas demand is lowered by 750 bcm in the STEPS scenario compared to the same scenario in the 2021 report. See page 365: IEA (2022) World Energy Outlook 2022.

10 European Investment Bank, 2019, 14 November, *'EU Bank launches ambitious new climate strategy and Energy Lending Policy'*, Press Release 2019-313-EN. Available at: https://www.eib.org/en/press/all/2019-313-eu-bank-launches-ambitious-new-climate-strategy-and-energy-lending-policy.

11 European Parliamentary Research Service, 2021, *'Revision of the TEN-E Regulation. EU guidelines for new energy infrastructure'*. Briefing. Available at: https://www.europarl.europa.eu/RegData/etudes/BRIE/2021/689343/EPRS_BRI(2021)689343_EN.pdf.

12 It is estimated that around EUR 10 bn of investments is needed to complement existing PCIs, see: European Commission (2022) REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition.

13 Gas for Climate, 2020, European Hydrogen Backbone. *How a dedicated hydrogen infrastructure can be created.* Available at: https://gasforclimate2050.eu/wp-content/uploads/2020/07/2020_European-Hydrogen-Backbone_Report.pdf.

In July 2020, the Commission's Energy Sector Integration[14] and Hydrogen Strategies[15] were published. They outlined some measures that would be needed for a more integrated, holistic approach to the energy sector and the uptake of renewable hydrogen. The Hydrogen Strategy set up the target of installing at least 6 GW of renewable hydrogen[16] in the EU by 2024 and 40 GW by 2030. This target has been increased by the REPowerEU plan and its ambition to produce 10 million tonnes and import an additional 10 million tonnes of renewable hydrogen into the EU by 2030.

In July 2021, the Fit for 55 package[17] provided a set of wide-ranging legislative revisions to meet the new 55% GHG emissions reduction target for 2030. The proposed legislative revisions concerning the hydrogen market echoed the ambitions set out in the Hydrogen Strategy, especially through a set of sub-targets proposed for the revision of the Renewable Energy Directive that aims to increase the target for renewable energy sources (RES) to at least 40% from the current 32%. In March 2022, it was proposed to further increase the target to 45%[18]. A binding target of 50% of hydrogen used as feedstock or energy carrier in the industrial sector is to be provided from renewable fuels of nonbiological origin (RFNBOs)[19], in addition to a 2.6% target for RFNBOs in the transport sector.

Most recently, the decarbonisation ambition has been exemplified in the 'Hydrogen and decarbonised gas market package', which has the goal to "remove barriers to decarbonisation and create the conditions for a more cost-effective transition" notably by promoting hydrogen and bio-methane[20].

1.1.2. Affordability and the energy price crisis

In parallel to the decarbonisation ambitions, since 2021, Europe faced an unprecedented crisis in price hikes in electricity and gas markets that engender additional socio-economic costs. After skyrocketing in the early autumn of 2021, high gas prices consequently led to an increase in electricity prices across Europe. In tandem, elevated electricity and gas prices have been exerting forceful pressure both on industries and households, urging national governments to safeguard at least the most vulnerable users[21]. High gas prices are remaining high and volatile also in 2022. After the Russian invasion, gas prices at the Title Transfer Facility (TTF) in the Netherlands rose to 170 euros/MWh in March 2022 and then fell to 90 – 100 euros/MWh before slowly starting to rise again in June and July and spiking end of August close to 350 euros/MWh[22]. Since then prices have fallen again and dropped below 100 euro/MWh in October, but remain volatile and much higher than previous years' averages.

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[14] European Commission, 2020b, 8 July, '*Powering a climate-neutral economy: An EU Strategy for Energy System Integration*', COM(2020) 299 final, Brussels. Available at: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=COM:2020:299:FIN.

[15] European Commission, 2020a, '*A hydrogen strategy for a climate-neutral Europe*', COM(2020) 301 final, Brussels. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0301.

[16] Standards for 'Low-carbon' hydrogen as to be proposed by the Commission based on full life-cycle GHG emissions.

[17] European Commission, 2021b, 14 July, '*European Green Deal: Commission proposes transformation of EU economy and society to meet climate ambitions*', Press Release IP/21/3541. Available at: https://ec.europa.eu/commission/presscorner/detail/en/IP_21_3541.

[18] As part of the REPowerEU Plan, the European Commission proposes to increase the renewable energy target from 40% to 45% under the Fit for 55 package and the Renewable Energy Directive. It also proposes to increase the target in the Energy Efficiency Directive to 13% and invites the Parliament and Council to enable additional energy efficiency gains in buildings through the Energy Performance of Buildings Directive (EPBD). However, discussions about these targets are ongoing both in the European Parliament and the Council.

[19] Examples of RFNBOs include hydrogen, ammonia or synthetic hydrocarbons like e-kerosene.

[20] European Commission, n.d., *Energy. Hydrogen and decarbonised gas market package*, COM(2021) 230 final. Available at: https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en

[21] Not only energy-intensive industries have scaled down production, also energy companies are increasingly reporting financial problems. For instance, companies such as EDF and Uniper were nationalised after severe liquidity issues.

[22] For development of TTF gas prices see: ICE Endex. Dutch TTG Gas Futures.

In response to the price hikes, the European Commission prepared a list of available remedies. The so-called 'Energy Toolbox' published in October 2021 presents measures to protect consumers and the industry[23]. Some measures that the Member States can implement in the gas sector such as joint procurement of strategic stocks by Transmission Operators (TSO) were further included in the revised Energy Package for gas. Not addressing the shorter-term objectives of security of supply may induce risks in the effectiveness of the long-term decarbonisation strategy for the gas sector and the overall economy. In addition, the Council of the EU agreed in September 2022 on a package of new emergency measures to address the energy crisis and rising energy prices[24]. It includes a uniform cap on the excess revenues of power plants not using gas for electricity production as well as a levy to capture surplus profits made by fossil fuel companies. The European Parliament also adopted a resolution in response to the increase in energy prices calling for additional emergency measures to ease the pressure of rapidly rising energy prices on consumers and businesses[25].

Beyond these measures addressing the symptoms, the current energy price calamity brings back one of the most sensitive questions of how the EU could and should urge to reach a sufficient level of resilience against external shocks on gas markets and its import dependence on fossil fuels. According to an assessment by ACER (European Union Agency for the Cooperation of Energy Regulators) and CEER (Council of European Regulators)[26], the 2021 and still ongoing gas price surge and volatility can be split into three phases:

- **Demand and supply dynamics** through a combination of a decrease in LNG imports combined with limited pipeline imports[27] whilst gas consumption was increasing as a result of the economic recovery from the COVID-19 pandemic (Q2 – Q3 2021);
- **Decreasing supplies of Russian gas before the war**, which despite increasing LNG imports placed upward pressure on EU gas prices as it occurred at a time when underground storage stocks were already low (Q4 2021 – Q1 2022); and
- **Increasing uncertainty** caused by the Russian invasion of Ukraine, which further increased upward pressure on gas prices and EU sanctions as well as Russian countermeasures also creating further concerns and actual reductions in the amount of gas being supplied from Russia (ongoing).

An earlier assessment also identified rising Emission Trading System (ETS) allowance prices and weather patterns impacting both the generation and demand of gas[28] as secondary factors[29].

[23] European Commission, 2021e, *Tackling rising energy prices: A toolbox for action and support*. Available at: https://ec.europa.eu/commission/presscorner/detail/en/fs_21_5213.

[24] Council of the EU, 2022, *Council agrees on emergency measures to reduce energy prices*. Available at: https://www.consilium.europa.eu/en/press/press-releases/2022/09/30/council-agrees-on-emergency-measures-to-reduce-energy-prices/.

[25] European Parliament resolution of 5 October 2022 on the EU's response to the increase in energy prices in Europe (2022/2830(RSP)). Available at: https://www.europarl.europa.eu/doceo/document/TA-9-2022-0347_EN.html.

[26] ACER and CEER, 2022(b), *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021*. Available at: https://www.acer.europa.eu/electricity/market-monitoring-report.

[27] In 2020, pipeline imports had fallen 4% compared to 2019, which was caused by an 18% decrease of Russian imports, (Heather, P., 2022, OIES).

[28] Severe weather in Asia in January 2021 had a marginal impact on European gas prices increasing them to EUR 26.46/MWh, which however was a short-term effect. In December 2021, extremely low temperatures in North-western Russia triggered another price rally (Heather, P., 2022, OIES).

[29] ACER and CEER, 2022(b), *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021*. Available at: https://www.acer.europa.eu/electricity/market-monitoring-report.

Beyond these drivers, research from the Oxford Institute for Energy Studies highlights the decrease in domestic production[30] and the role of **the low underground storage (UGS) levels**, which were on the low margin of a 10-year average in the second half of 2021. This added to the overall market nervousness during the winter of 2021-2022. The lag in filling gas storage was spotted back in April of 2021 and intensified in the summer as withdrawals increased[31].

The existing market model does not foresee a remuneration for storage for unforeseen events, which cannot be covered by a market value. In addition, companies responsible for storage get profits out of the service and add up to the costs for the market players. Lack of the so-called 'insurance value' for UGS has been a long-standing problem that put already storage operations under pressure jeopardising not only future planned investments but also existing levels of storage capacity. In the past, some Member States introduced storage obligations[32], which were subject to scrutiny by the European Commission for their compliance with EU State Aid provisions[33].

Additionally, the existing regulation on the UGS filling did not prevent the situation during the winter of 2021-2022 when a large part of market participants did not book capacity because of elevated prices. Low gas stocks for winter 2021/22 intensified the discussion on the role of UGS in the security of supply, and in March 2022 the EU tabled a proposal to revise Regulation (EU) 2017/1938 on gas supply security, among others, introducing an obligation of a minimum 80% gas storage level for the winter of 2022/23.

Box 1.1: Europe's gas market at a glance

Demand

During the last decade, demand for natural gas in the EU and the UK increased by around 200 TWh/year, reaching 5232 TWh/year in 2021. This growth was sustained by coal-to-gas switching across the EU stimulated inter alia by low gas prices on global markets during 2015-2020. Germany, Italy and the UK account for more than half of total EU and UK gas consumption, while the share of 12 Member States with the lowest gas demand reaches only 10%. Across the Member States, gas consumption showed local dynamics, in line with the presence of energy-intensive industries and the share of gas-fired plants in power generation. For a detailed overview of gas consumption per country and sector, see Fischer, L. and Ivanova, V. (2022).

After a steep fall predominately resulting from the economic impact of COVID-19 in 2020, the demand recovered in 2021 also due to the longer winter of 2020-21 and followed hot summer, reaching its five-year maximum in the first half of 2021. However, the elevated gas prices in late summer 2021 started putting pressure on European gas markets inducing reduced use of natural gas in power generation (over -20% YoY in Q3 2021) and lowered industrial demand in energy-intensive sectors (-10% YoY Q3 2021). In 2022, as a result of Russia's invasion of Ukraine, sustained high gas prices, and mild weather that ended the heating season of 2022 earlier, gas demand fell further. ACER and CEER (2022) estimated a drop of -9.5% YoY to May 2022. The Quarterly Report on European Gas Markets Quarterly provides a fall of 16.1% in Q2 2022 YoY. In power generation, the gas-to-coal switch continued, particularly in Northwest Europe and Central Europe, despite increased carbon emission allowances that marked the historical high in February 2022.

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[30] Compared to 2019, domestic production fell by 13%, which was caused mainly by the reduced output of the Dutch Groningen field. See: Heather, P. (2022) A Series of Unfortunate Events - Explaining European Gas Prices in 2021: The role of the traded gas hubs.

[31] Fulwood, M and Sharples, J., 2021, *Why Are Gas Prices So High?*, The Oxford Institute for Energy Studies. Available at: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/09/Why-Are-Gas-Prices-So-High.pdf.

[32] Some Member States have already similar provisions, e.g., Italy and Hungary. The role of gas storage in internal market and in ensuring security of supply (2015).

[33] European Commission, 2021d, 28 June, *State aid: the Commission authorises the regulatory mechanism for the storage of natural gas in France*, Press Release. Available at: https://ec.europa.eu/commission/presscorner/detail/en/IP_21_3281.

A need to minimise the effects of reduced supplies and possible disruptions from Russia may further incentivise fuel switching and voluntary demand reduction, including those proposed in the Communication 'Save gas for a safe winter'.

Supply

The EU-UK gas supply portfolio is marked by a high import dependency, which reached nearly 84% in 2021. For some Member States, including the largest gas markets of Germany and Italy, the dependence exceeds 90%. The fall of domestic production almost by two-thirds in 2021 (up to only 17% of the total gas supply) was increasingly filled by imports. Among the key suppliers to the EU-UK, in 2021 imports from Russia reached 34.4%, from Norway – 23.9%, from Algeria – 7.4%, and 2.5% were filled by other pipeline imports from Libya and Azerbaijan. LNG imports constituted 17.5%.

Although the share of Russian pipeline and LNG imports was steadily growing during the last decade (reaching almost 47% in 2019), over 2020-2021, it dropped substantially following LNG inflow in 2020 and Gazprom's strategy of tight short-term gas sales in 2021. In the first half of 2022, pipeline supplies from Russia fell further: ACER and CEER (2022) estimated only 20% of pipeline gas from Russia in the total EU-UK supply portfolio for the first half of 2022. The drop in Russian pipeline imports was partially refilled by LNG imports that rose by 60% YoY in the first half of 2022. This inflow is largely possible because of the sustained price spreads between the European and Asian gas markets. Particularly, LNG imports from the USA raised to 14.8% of the total EU-UK gas supply, compared to 5.5% in 2021, for the first time overtaking Russian pipeline gas imports into the EU in June 2022. However, there can be also a limited role of US LNG deliveries due to the current constraints in liquefaction capacity and gasification units, as recently discussed at the Florence School of Regulation. As estimated by the IEA (2022), a drop of about 60 bcm or 50% of Russian piped gas imports into the EU was recorded in January-October 2022 YoY, By the end of the year, a reduction could reach about 80bcm. For 2022, the IEA expects Russian piped gas imports could reach about 60 bcm. These volumes will need to be sourced should further reductions of Russian supplies occur in 2023 onwards.

Sources: ACER Chest Application, n.d., *EU MSs gas consumption 2012-2021 TWh/year*; ACER and CEER, 2021, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020. Gas Wholesale Markets Volume*. July 2021; ACER and CEER, 2022, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021*. *Gas Wholesale Markets Volume*. July 2022. IEA, 2022, *Gas Market Report, Q3-2022, including Gas 2022 medium-term forecast to 2025*. International Energy Agency, Paris; Ember, n.d., *EU Carbon Price Tracker*; Fischer, L. and Ivanova, V, 2022, *EU gas sector. Data for decision-makers*; European Commission, 2022, *The Quarterly Report on European Gas Markets Quarterly. Volume 15 (issue 2 covering the second quarter of 2022);* IEA, 2022, *Never Too Early to Prepare for Next Winter: Europe's gas balance for 2023-2024*; Florence School of Regulation, 2022, *The limits of using LNG to save the EU: not enough infrastructure and a tricky global LNG price*.

1.1.3. Autonomy and the Russian invasion of Ukraine

Substantial shocks went across EU energy markets after Russia invaded Ukraine in February 2022 raising the urgency to secure physical energy supply stocks, either in the case of Russian supply cuts or further EU embargos on energy resources. In its several consecutive packages of sanctions, the EU targeted almost all sectors of Russia's economy – but gas supplies[34]. After almost a month of negotiations, the EU adopted the sixth package of sanctions in June 2022[35], which included a partial embargo on Russian oil. These sanctions will ban Russian seaborne oil imports from December 2022 and all petroleum product imports from February 2023 onwards. A seventh package was agreed upon on 21 July, which includes sanctions on Russian gold but also avoids any embargo on natural gas[36]. Recently, an eighth sanction package was announced, which among others will introduce a price cap on Russian oil[37]. Contrarily, already in April 2022, the European Parliament made a call for a full embargo of all Russian energy goods[38].

With political tensions between the EU and Russia intensifying after the decree of the President of Russia signed on 31 March 2022 to require buyers from the so-called 'unfriendly countries' to pay in roubles for gas delivered after 1 April 2022[39], drastic reductions in Russian imports are needed. Several Member States[40] refused to change the payment structure and needed to source non-Russian gas already from that moment in time. Russia also increased the pressure by first reducing natural gas flows through the Nord Stream 1 pipeline, then stopping flows completely due to maintenance, before resuming again at an even lower rate. In late August, the operation of the pipeline was shut down entirely by Russia, citing issues with equipment. The latest development has been the discovery of four leaks in both the Nord Stream 1 and 2 pipelines, which the European Commission and some Member States identified as likely acts of sabotage[41].

[34] Akhvlediani, T. and De Groen W.P., 2022, *Sanction-prove or sanction-hit*. CEPS Policy Insight #2022-10. Available at: https://www.ceps.eu/ceps-publications/sanction-proof-or-sanction-hit/.

[35] CSIS, 2022, 8 June, *European Union Imposes Partial Ban on Russian Oil*. Available at: https://www.csis.org/analysis/european-union-imposes-partial-ban-russian-oil.

[36] Reuters, 2022, 14 July, *Gas won't make EU's next Russian sanctions package, Czech leader says*. Available at: https://www.reuters.com/world/europe/gas-wont-make-eus-next-russian-sanctions-package-czech-leader-says-2022-07-13/.

[37] European Commission, 28 September, Press statement by President von der Leyen on a new package of restrictive measures against Russia. Available at: https://ec.europa.eu/commission/presscorner/detail/en/STATEMENT_22_5856.

[38] European Parliament, 2022, *MEPS demand full embargo on Russian imports of oil, coal, nuclear fuel and gas*. Available at: https://www.europarl.europa.eu/news/en/press-room/20220401IPR26524/meps-demand-full-embargo-on-russian-imports-of-oil-coal-nuclear-fuel-and-gas.

[39] Azon, A., 2022, *Rouble gas payment mechanism: implications for gas supply contracts,* The Oxford Institute for Energy Studies. Available at: https://www.oxfordenergy.org/publications/rouble-gas-payment-mechanism-implications-for-gas-supply-contracts/.

[40] As of 15.07.2022 among these Member States are Bulgaria, Denmark, Finland, Netherlands and Poland.

[41] BBC News, 2022, 29 September, *Nord Stream 1: How Russia is cutting gas supplies to Europe*. Available at: https://www.bbc.com/news/world-europe-60131520.

In light of these tensions, the urgency to diversify supply by sourcing additional, non-Russian gas, and reducing overall gas demand becomes apparent. To address this, the REPowerEU communication[42] outlined the ambition to reduce the EU's dependency on Russian gas by two-thirds, at least 50 bcm of additional LNG and 10 bcm of non-Russian piped gas need to be sourced by the end of 2022. For the EU's gas markets that would mean that interconnectors would need substantial capacities to re-direct gas flows[43]. For example, a substantial increase in capacity is needed between Spain and France to bring imported LNG from Spanish LNG terminals further into the continent. Following the communication, the REPowerEU Plan[44] provides an initial assessment of the required infrastructure and estimates an investment need of EUR 10 billion by 2030[45]. One of the proposed instruments to diversify supply and strengthen the EU's bargaining power vis-à-vis gas exporters is to pool demand through the EU Energy Platform. This will be followed by the set-up of a voluntary joint purchasing mechanism.

It also becomes a priority **to ensure energy resilience and independence for the EU by strengthening gas interconnections and increasing LNG imports** (mostly from the USA and Qatar, potentially West Africa) **and pipeline imports** (Norway, Algeria, Azerbaijan) as well as strengthening cooperation between the main gas importers within the G7. The EU External Energy Engagement Strategy[46] published on 18 May 2022 outlines a set of measures aimed among others at diversifying the EU's gas supplies. One of the proposed instruments to diversify supply and strengthen the EU's bargaining power vis-à-vis gas exporters is to pool demand through the EU Energy Platform. This will be followed by the set-up of a voluntary joint purchasing mechanism.

Beyond diversification, the REPowerEU plan's proposed measures target also the reduction of gas demand through increased targets for energy efficiency and RES as well as behavioural change. In July 2022, the European Commission published its communication Save gas for a safe winter[47], which proposes a Regulation on Coordinated Demand Reduction Measures for Gas, which would require all Member States to reduce gas demand by 15% by March 2023 and would allow the European Commission to trigger a Union Alert to impose mandatory gas demand reduction if there is the risk of a severe gas shortage. In November 2022, as part of REPowerEU, the European Commission also proposed a temporary one-year regulation to speed up permitting for RES projects through emergency measures[48].

42 European Commission, 2022c, *REPowerEU: Joint European Action for more affordable, secure and sustainable energy*, COM(2022) 108 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A108%3AFIN.

43 For example, a substantial increase in capacity is needed between Spain and France to bring imported LNG from Spanish LNG terminals further into the continent. See: Fulwood, M et al., 2022, *The EU plan to reduce Russian gas imports by two-thirds by the end of 2022: Practical realities and implications*, The Oxford Institute for Energy Studies. Available at: https://www.oxfordenergy.org/publications/the-eu-plan-to-reduce-russian-gas-imports-by-two-thirds-by-the-end-of-2022-practical-realities-and-implications/.

44 European Commission, 2022b, *REPowerEU Plan*, COM(2022) 230 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483.

45 In addition, the plan outlines a total need of EUR 210 bn in investments, which comes on top of what is needed to realise the objectives of Fit for 55. According to the plan, this will be realised among other through a revised RRF proposal, dedicated calls under the Innovation Fund and the Connecting Europe Facility.

46 European Commission, 2022a, *EU external energy engagement in a changing world*, JOIN(2022) 23 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=JOIN%3A2022%3A23%3AFIN&qid=1653033264976.

47 European Commission, 2022d, *Save gas for a safe winter*, COM(2022) 360 final. Available at: https://energy.ec.europa.eu/communication-save-gas-safe-winter_en.

48 European Commission, COM(2022) 591 final, Proposal for a Council Regulation laying down a framework to accelerate the deployment of renewable energy. Available at: https://energy.ec.europa.eu/proposal-council-regulation-laying-down-framework-accelerate-deployment-renewable-energy_en.

The geopolitical context further requires energy independence as an indispensable part of the EU's strategic autonomy. It underlines the importance to accelerate Europe's energy independence and ensure transitioning policies and mitigating the obstacles to investments in renewable sources of energy and the relevant infrastructure. **Combining mid-term security of supply measures with the long-term objectives of upscaling low-carbon gases has been the core of the 'Hydrogen and decarbonised gas market package'**. In particular, it aims to facilitate the penetration of renewable and low-carbon gases into the energy system to facilitate (i) the decarbonisation of the gas sector; (ii) the deployment of a cross-border hydrogen infrastructure and competitive hydrogen market, (iii) better network planning; and (iv) security of supply and storage to ensure resilience against gas market volatility and elevated prices.

1.2. The EU regulatory framework for gas

In light of the above-mentioned opportunity to develop an environmentally friendly and decarbonised EU gas market and the challenges to affordability, competitiveness, energy security and autonomy, it is important to reflect on the current and envisioned EU regulatory framework for gas and its preparedness to address these issues.

1.2.1. The current regulatory framework

Energy policy in the EU is implemented by several Directives and Regulations (see Figure 1.1 for an overview at the end of this section). Specifically, for the gas market, the current regulatory framework was introduced in 2009 when the **Third Energy Package** was adopted, which is a legislative package for an internal gas and electricity market in the EU. In particular, for gas, it included the **'Gas Regulation'** on conditions for access to the natural gas transmission networks, and the **'Gas Directive'** on common rules for the internal market[49].

Similar to its two preceding packages, the Third Energy Package aimed to liberalise and build a competitive EU market for gas and electricity. In that sense, the main objective of the regulatory package was to complete the internal market for electricity and gas by harmonising the different processes of energy systems and markets in the EU[50]. To achieve this, it proposed rules for unbundling energy suppliers from network operators. In addition, the regulation covers four other main areas:

- Strengthening the independence of national regulatory authorities (NRAs) and their ability to make binding decisions, impose penalties and collect accurate data;
- Establishment of the European Union Agency for the Cooperation of Energy Regulators (ACER) to ensure cooperation among NRAs and the functioning of the internal market in particular for cross-border issues;
- Cross-border cooperation not only between regulators but also between TSOs through the creation of European Networks for TSOs[51] responsible for developing standards and drafting network codes; and
- Open and fair retail markets and consumer protection.

[49] Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks and Directive 2009/73/EC concerning common rules for the internal market in natural gas.

[50] European Parliamentary Research Service, 2021, *'Revision of the TEN-E Regulation. EU guidelines for new energy infrastructure'*. Briefing. Available at: https://www.europarl.europa.eu/RegData/etudes/BRIE/2021/689343/EPRS_BRI(2021)689343_EN.pdf.

[51] The European Network for Transmission System Operators for Electricity (ENTSO-E) and the European Network for Transmission System Operators for Gas (ENTSOG).

In addition to the Third Energy Package as highlighted in Figure 1.1, there are several other EU policies in the domain of EU Energy policy and gas.

Regulation (EU) No 347/2013 on guidelines for a Trans-European Network for Energy, also referred to as the '**TEN-E Regulation'** was introduced in 2013 to support the deployment of large-scale energy infrastructure in a cross-border setting. The regulation aimed to ensure the security of supply in the gas market by addressing obstacles such as the extensive time required for projects to acquire building permits, regulatory challenges for cross-border projects, and the lack of commercial viability of large-scale infrastructure projects, particularly in light of the limited financing capacities of TSOs and difficulties to attract investments. The evaluation of the TEN-E Regulation finds that for gas TEN-E substantially contributed to infrastructure development and supply resilience[52]. This is also due to financing support from the **Connecting Europe Facility**, which provided targeted support to gas interconnectors in Central and Eastern Europe reducing the dominance of external suppliers.

In 2017, **Regulation (EU) 2017/1938 on gas supply security** was introduced replacing the original Regulation 994/2010, which came to be as a reaction to the 2009 transit crisis[53] and contributed to bi-directional gas capacities in Central and Eastern as well as South-East Europe. Nevertheless, a study looking into import dependency, the concentration of the gas market and gas reserves found that between 2005 and 2015, on average the level of security of gas supply fell in the EU highlighting increased vulnerabilities[54]. To address this, the new regulation should ensure a coordinated and common approach to the security of supply across EU Member States. As such, the regulation can be considered a large step forward, however, it also allows for many exemptions for Member States unwilling to participate in its solidarity mechanism and does not consider renewable gases[55].

Finally, the part of the Third Energy Package that relates to the electricity market was updated with the **Clean Energy for all Europeans package**[56], which was adopted in 2019 to overhaul the EU's energy policy framework with the ambition to move toward renewable energy production including eight new directives and regulations governing energy efficiency, renewable energy, energy performance of buildings, electricity market design, and the governance of the energy union and climate action.

52 European Commission, 2021a, Directorate-General for Energy, Akkermans, F., Le Den, X., Heidecke, L., et al., Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure, Publications Office, 2021. Available at: [Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure.]

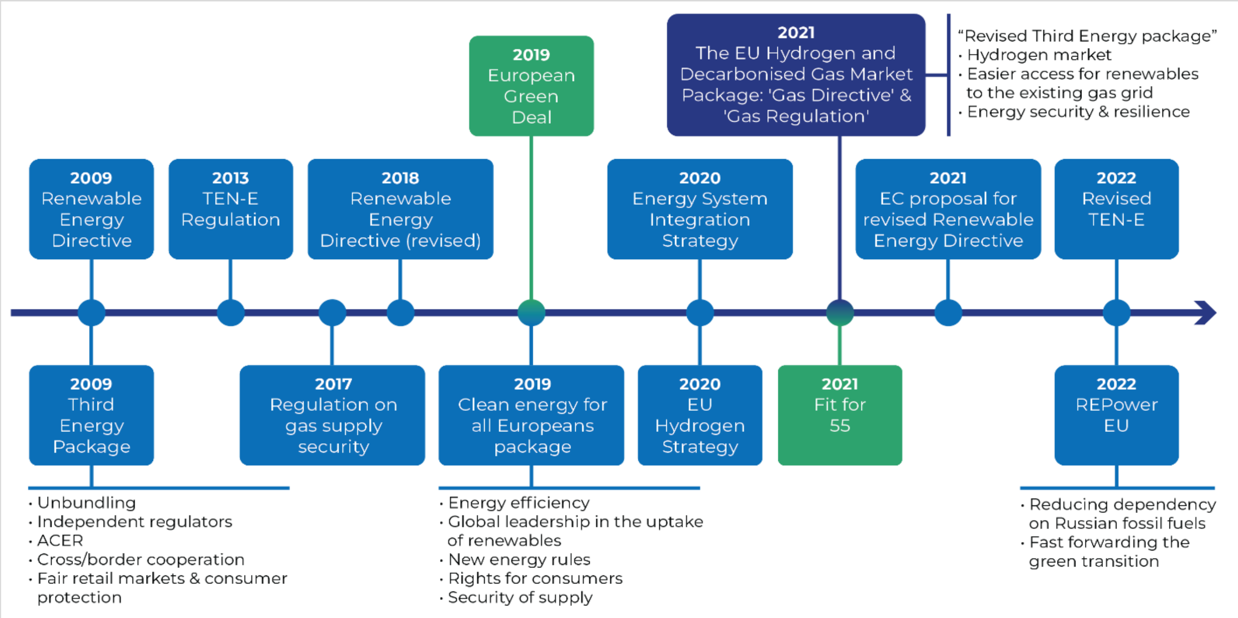
53 The 2009 transit crisis refers to a gas dispute between Russia and Ukraine, whereas both sides failed to agree on a price for Russian gas supply and a tariff for the transit of Russian gas to Europe, which led to the stop of Russian exports to Ukraine and 16 EU Member States. This crisis lasted from 07.01 to 20.01.2009.

54 Tejada, V., 2022, Improving the concept of energy security in an energy transition environment: Application to the gas sector in the European Union. Available at: https://www.sciencedirect.com/science/article/pii/S2214790X2200003X#.

55 Fleming, R., 2019, *A legal perspective on gas solidarity*. Available at: https://www.sciencedirect.com/science/article/pii/S0301421518306505.

56 European Commission, 2016, *Clean Energy For All Europeans*, COM(2016) 860 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2016:0860:FIN.

Figure 1.1: Timeline of EU regulation in energy and gas



Source: Author's elaboration based on European Commission publications.

1.2.2. The impact of the Third Energy Package for Gas

The failure of the second Gas Directive 2003/55/EC to lead to a competitive EU gas market due to the differences in how the Member States implemented it has led the Third Energy Package to be highly prescriptive describing precisely in which ways to achieve liberalisation. With this more prescriptive approach consisting of a Directive and Regulation, the **EU was successful in creating a single competitive gas market** with a competitive wholesale gas market. The framework furthermore allowed for sufficient flexibility through derogations so emerging markets could develop, for example, exemptions to emerging and isolated markets regarding the implementation of unbundling rules[57]. This positive sentiment is also echoed by the evaluation of the European Commission, which found that "the reinforcement of unbundling requirements has had a positive effect on the competition with new players entering the gas market" adding however that "in some Member States the incumbent still holds a dominant position"[58].

The evaluation further finds that market integration improved because of increasing cross-border trade as well as growing cooperation between TSOs and between NRAs. Overall, while creating certain administrative costs for undertakings and regulators, these have not been perceived as too heavy and seem to be outweighed by the benefits of increased competition and welfare gains. Nevertheless, the evaluation identified also some shortcomings:

- cross-border cooperation between TSOs and NRAs might prove insufficient in light of challenges related to the decarbonisation of the gas sector (e.g. gas quality management, market mergers);

[57] Barnes, A., 2020, *Can the current EU regulatory framework deliver decarbonisation of gas?* Available at: https://www.oxfordenergy.org/publications/can-the-current-eu-regulatory-framework-deliver-decarbonisation-of-gas/#:~:text=The%20framework%20will%20not%20deliver,transition%20to%20a%20decarbonised%20future.

[58] European Commission, 2021c, *Evaluation Report on the Gas Directive and the Gas Regulation*, SWD(2021) 457 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021SC0457&from=EN.

- the benefits of market integration are not fully passed on to EU consumers with price regulation, lack of access to data, insufficient tools for comparison and lack of ease to switch suppliers mentioned as barriers;
- lack of coherence with the different provisions about energy security in the gas sector; and
- existing rules do not cater for the decarbonisation of the energy system and disregard the emergence of new energy carriers, in particular renewable and low-carbon gas.

Addressing the previously mentioned shortcomings of the Third Energy Package for Gas, but also complementing the decarbonisation ambitions that the Clean Energy for all Europeans package introduced for the electricity market, the European Commission proposed the 'Hydrogen and decarbonised gas market package'. In the following section, we will review how it proposes to change the regulatory framework for gas and how it fits with other proposed regulatory changes.

1.2.3. The revision of the Third Energy Package for Gas

One of the 20 action points of the 2020 **EU Hydrogen Strategy**[59] was to design enabling market rules for the deployment of hydrogen through the review of the gas legislation. To achieve this, the 'EU Hydrogen and Decarbonised Gas Market Package' proposes to revise the 'Gas Directive' and 'Gas Regulation'. With this package and the ambition to adopt a comprehensive governance system for hydrogen and decarbonised gases, the EU is the first to start on the path of regulating a new hydrogen market[60]. Other countries, such as South Korea, simply incorporated governance on hydrogen in the existing gas market governance structures.

As previously introduced (see Section 1.1), the proposed revision aims to enable renewable and low-carbon gases to enter the market to facilitate decarbonisation of the gas market, improve the market conditions and increase the engagement of gas consumers as well as ensure the security of supply and resilience against gas market volatility and elevated prices. For this purpose, it addresses barriers such as the lack of a cross-border hydrogen infrastructure, a lack of a competitive hydrogen market and a lack of network planning. In addition, the package proposes amendments to the security of gas supply regulations.

Key changes proposed in the package are:

- In terms of network planning, it proposes the establishment of a **European Network of Network Operators for Hydrogen** (ENNOH) by 1 September 2024 to promote the development of hydrogen infrastructure, cross-border coordination and interconnector network construction (incl. through Ten Year Network Development Plans), elaborate on specific technical rules and write network codes. Furthermore, it proposes to set up an entity for European DSOs (Distribution System Operators)[61]. These entities should intensify coordination between TSOs and DSOs and enhance network planning activities for the transmission and distribution of hydrogen;

[59] European Commission, 2020a, '*A hydrogen strategy for a climate-neutral Europe'*, COM(2020) 301 final, Brussels, 07.07.2020. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0301.

[60] Kneebone, J., 2021, 16 December, *A first look at the EU Hydrogen and Decarbonised Gas Markets Package*, Florence School of Regulation. Available at: https://fsr.eui.eu/a-first-look-at-the-eu-hydrogen-and-decarbonised-gas-markets-package/#_ftn4.

[61] Similarly to the one that had been set-up for electricity DSOs: https://www.eudsoentity.eu/.

- **To develop hydrogen infrastructure**, hydrogen interconnection projects will become eligible to apply for funding if they are not already covered under the Important Projects of Common European Interest (IPCEIs);
- **To encourage the use of renewable and low-carbon gases**, it proposes the removal of tariffs for cross-border interconnections and lowering tariffs at injection points to ensure easier access to existing gas grids. In particular, renewable and low-carbon hydrogen would receive a 75% discount from various entry and exit tariffs. Moreover, until 1 January 2031 tariffs would not be chargeable against the transmission of low-carbon and renewable gases across Member State interconnection points. Finally, blends of up to 5% hydrogen in the natural gas flow should be facilitated at cross-border points from October 2025 to facilitate the use of existing gas infrastructure in the absence of a dedicated hydrogen infrastructure;
- **A certification system** would be introduced for renewable and low-carbon gases allowing them to qualify for these exemptions;
- **For consumer empowerment,** the proposed regulations are modelled after the electricity market, which is seen as more consumer friendly. They facilitate switching between suppliers, ensure access to comparison tools, improve accessibility to information, support the deployment of smart meters and facilitate active customers to sell renewable energy; and
- **Security of supply** through cybersecurity provisions and voluntary measures for the Member States on imposing minimum storage requirements and introducing incentives for gas storage. It also provides the option of joint procurement of strategic stocks.

Beyond these proposed changes, many of the existing rules for natural gas are carried over to the decarbonised gas market. This includes **unbundling requirements** for TSOs and network operators with **ownership unbundling** being the default rule for hydrogen network operators. Similarly, third-party access (TPA) to the natural gas and hydrogen grids as well as storage and terminals remains unchanged. However, there are some exemptions to this, for example, Member States can choose to not grant TPA to their hydrogen network until 31 December 2030 (Art. 31 Directive). Until the same cut-off date, Member States can also apply the rule on **independent transmission operators** for unbundling hydrogen network operators[62].

The exemptions aim to attract private investments in the development of renewable hydrogen and low-carbon infrastructure. Moreover, incentives are applied to encourage the repurposing of natural gas infrastructure and avoid creating stranded assets. These exemptions and incentives are combined with a two-stage approach (before and after 2030) [63] and the establishment of regulatory principles to create certainty and an environment conducive to investments[64].

Both the exemptions and the phased approach seem to acknowledge the tension between promoting investment while creating a competitive market that is contained within the proposed package.

[62] Kneebone, J., 2021, 16 December, *A first look at the EU Hydrogen and Decarbonised Gas Markets Package*, Florence School of Regulation. Available at: https://fsr.eui.eu/a-first-look-at-the-eu-hydrogen-and-decarbonised-gas-markets-package/#_ftn4.

[63] Up to 2030, rules in the area of TPA, tariffs, financial rules for cross-border hydrogen and unbundling will remain flexible. After 2030, a stricter regulatory regime will come into effect including among other regulated TPA and no hydrogen tariffs at interconnection points. After 2049, also long-term gas supply contracts will be banned.

[64] Tanase, L. and Herrera Anchustegui, I., 2022, 21 March, *The EU Hydrogen and Decarbonised Gas Market Package: Revising the governance and creating a hydrogen framework*, Florence School of Regulation. Available at: https://fsr.eui.eu/the-eu-hydrogen-and-decarbonised-gas-package-revising-the-governance-and-creating-a-hydrogen-framework/#_ftn1.

This has also led to criticism with a central concern being that the strict unbundling requirements will prevent the required private investments. The concern is that strict requirements will prevent electricity and gas TSOs from making the necessary capital-intensive investments in hydrogen infrastructure[65].

The flexible and phased regulatory approach is however also seen as positive as it would avoid overregulating the still-emerging market[66]. A further discussion on unbundling and its role in the gas market is provided in Chapter 2.

Further criticism has been targeting the **proposal to allow the blending of up to 5% of hydrogen** with natural gas at interconnectors as it hinders efficient resource use and maintains purity levels for the industry relying on hydrogen for its decarbonisation[67]. Discussions with stakeholders in our workshop highlighted that with the lack of dedicated hydrogen infrastructure, blending is a useful tool to accelerate hydrogen production while infrastructure is still being built. Similarly, the European Commission[68] sees a limited role for blending as a transitional solution in areas where pure hydrogen cannot be absorbed. Therefore, the proposal to allow blending at interconnectors is important to avoid stopping cross-border flows.

Moreover, the lack of a complete definition for renewable and low-carbon hydrogen that is consistent with the Hydrogen Strategy has been criticised as it could be a barrier to investment decisions[69]. The debate around the definitions has been regarding, for example, the additionality of RES in hydrogen production, i.e. renewable energy used for the production of hydrogen having to be additional to the other renewable energy consumption. The proponents of the principle, such as consumer organisations, consider additionality necessary to avoid a further raise in energy prices for consumers[70]. A Delegated Act proposal in the Renewable Energy Directive II included requirements on the use of RES in addition to existing sources of hydrogen, but the rather strict requirement on additionality was rejected by the European Parliament.

Others also criticised the decision to set up a separate entity (ENNOH) to be tasked with the development of network plans, arguing that better integration of hydrogen and gas network activities, such as network planning and security of supply, is needed[71]. The European Commission argues though as hydrogen will be an energy carrier in its own right, a dedicated entity would be better at knowing the needs of network operators, producers and users.

Beyond the revision of the 'Gas Regulation' and 'Gas Directive', also other EU policies and proposals are changing the regulatory framework for gas. In particular, the **revision of the gas security regulation** ((EU) 2017/1938), which has been proposed as part of the revision of the Third Energy Package for gas and would introduce a solidarity principle, shifting from a national to a regional approach for the security of supply measures and reinforcing cooperation with EU neighbours.

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65 See for example, Ehler, C., 13 July 2022, [Hydrogen's golden potential beckons](), Euractiv.

66 European Roundtable on Climate Change and Sustainable Transition, 2022, *The hydrogen and decarbonized gas market package – focus on hydrogen*, ERCST FEEDBACK. Available at: https://ercst.org/ercstfeedback-to-the-h2-and-gaspackage-proposals/.

67 Bellona Europa, 8 July 2022, *Gas market package: 3 amendments we like and why*. Available at: https://bellona.org/news/climate-change/2022-07-gas-market-package-3-amendments-we-like-and-why.

68 As stated by Ms Kitti Nyitrai, Head of Unit Decarbonisation and sustainability of energy sources, DG ENER at Hydrogen Europe's Hydrogen Talk: Assessing the hydrogen and decarbonised gas package, 05 October 2022, available at: https://hydrogeneurope.eu/h2-talks/.

69 European Roundtable on Climate Change and Sustainable Transition, 2022, *The hydrogen and decarbonized gas market package – focus on hydrogen*, ERCST FEEDBACK. Available at: https://ercst.org/ercstfeedback-to-the-h2-and-gaspackage-proposals/.

70 BEUC, 2022, *Hydrogen must be produced with new renewable electricity to safeguard the Commission's action on energy prices*. Available at: https://www.beuc.eu/letters/hydrogen-must-be-produced-new-renewable-electricity-safeguard-commissions-action-energy.

71 ENTSOG (2022) ENTSOG High-Level Position On Hydrogen And Decarbonised Gas Market Package.

This is seen as key to ensuring better coordination between the Member States in particular when it comes to common risks and available resources. According to ACER and CEER, to apply this regulation fairly, a review of the national filling targets for gas storage is required to allow for a balanced burden sharing across the Member States. They further add that while the provisions address the principle of storage in another Member State, they lack arrangements for sharing the financial and physical burden and for guaranteeing that the stored gas remains available to a Member State regardless of the situation[72].

In light of the Russian invasion, **the gas security regulation was amended in June 2022** following a proposal by the European Commission. This amendment included measures to deal with market imbalances for energy and requires UGS in EU countries to be filled by at least 80% of their capacity before the winter of 2022/2023 (and 90% in the subsequent winter periods)[73]. Security of gas supply was further enforced by the **'Save gas for a safe winter'** package, which gives the European Commission the possibility to mandate 15% cuts in gas consumption in times of scarce supplies. The proposal faced criticism from Poland, Portugal, Spain, Cyprus and Greece[74], however, the Council of the EU adopted it albeit in a less strict version that provides additional exemptions for the Member States[75].

The EU Hydrogen Strategy is completed by the **REPowerEU plan** of May 2022 and its ambition is to produce 10 million tonnes and import an additional 10 million tonnes of renewable hydrogen into the EU by 2030. It introduces the 'hydrogen accelerator', which aims to scale up the deployment of renewable hydrogen by committing to the IPCEI Hy2Tech containing 41 hydrogen projects and by creating a European hydrogen facility to enable investment security and business opportunities. The IPCEI Hy2Use, a project approved by the Commission in September 2022, complements Hy2Tech by supporting the construction of hydrogen-related infrastructure and the development of technologies for the integration of hydrogen into the industrial sector[76]. Finally, the **revision of the TEN-E regulation** introduces hydrogen infrastructure (incl. transport and certain types of electrolysers) as a category for European network development and Projects of Common Interest (PCI). This also includes the conversion of the existing natural gas infrastructure, which should support investments in infrastructure development for hydrogen. It also introduces smart gas grid investments as a new PCI category[77].

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72 ACER and CEER, 2022(a), *ACER and CEER views on the proposal for a regulation amending Regulations (EU) 2017/1938 and (EC) n°715/2009 relating to the access to gas storage facilities*. Available at: https://www.ceer.eu/documents/104400/-/-/71ed6155-e199-07e1-b564-3e7064d6fea9.

73 For more information, see European Commission, Secure gas supplies, available at: https://energy.ec.europa.eu/topics/energy-security/secure-gas-supplies_en.

74 Hernandez, A et al., 21 July 2022, *Southern rebellion threatens to sink EU gas rationing plan*, Politico. Available at: https://www.politico.eu/article/poland-portugal-spain-syprus-greece-rebellion-eu-gas-rationing-rules/?utm_source=Facebook&utm_medium=social&utm_campaign=RSS_Syndication.

75 Council of the EU, 26 July 2022, *Member states commit to reducing gas demand by 15% next winter*, Press release. Available at: https://www.consilium.europa.eu/en/press/press-releases/2022/07/26/member-states-commit-to-reducing-gas-demand-by-15-next-winter/.

76 European Commission, n.d., Energy Systems Integration, Hydrogen. Available at: https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen_en#hydrogen-accelerator.

77 European Parliamentary Research Service, 2021, *'Revision of the TEN-E Regulation. EU guidelines for new energy infrastructure'*. Briefing. Available at: https://www.europarl.europa.eu/RegData/etudes/BRIE/2021/689343/EPRS_BRI(2021)689343_EN.pdf.

2. THE IMPACT OF UNBUNDLING RULES ON GAS AND HYDROGEN

KEY FINDINGS

To avoid actors in the market for transmission and distribution of gas abusing their monopolistic positions, **unbundling requirements have been introduced to ensure that market actors performing competitive activities are restrained in their ability to also perform monopolistic activities**. This creates a market in the EU that can be described as a regulated monopoly. The Third Energy Package considerably reinforced unbundling rules, putting rules in place to ensure that energy supply and generation are separated from the operation of transmission or distribution networks.

Unbundling rules are implemented differently across Member States since derogations and exemptions allow the Member States with emerging markets flexibility in the type of unbundling regimes. However, in general, a trend towards an increasing level of unbundling can be observed. Moreover, there is a trend towards further privatisation and consolidation of TSOs, as well as a trend in increasing third-country participation in EU TSOs. While the number of TSOs is generally low, with most Member States having one to three TSOs (apart from Germany with 12), the DSO landscape is highly heterogeneous in number and size.

In general, **the Third Energy Package for Gas was successful in both creating a single competitive gas market as well as improving the security of supply**. Derogations also provided sufficient flexibility for emerging markets to develop. The challenges for the development of a similar hydrogen infrastructure are however manifold and start from the main issue that the overall market is still emerging and currently driven more by policy objectives than demand. The main aim of the Third Energy Package for Gas was **to provide access to existing infrastructure and not to provide incentives for the development of new infrastructure**.

Considering the similarities between the natural gas and the hydrogen market, the proposed extension of unbundling rules to the hydrogen and the decarbonised gas market would bring regulatory certainty. The proposal includes the **introduction of market and network regulation in a phased approach**, with the key cut-off date being 31 December 2030. After this date, exceptions particularly those entailing third-party access, unbundling and tariff structures will be removed and a strict regulatory regime will be installed.

Stakeholders have raised **concerns that these strict requirements will prevent network operators using the ITO model from making the necessary capital-intensive investments** in hydrogen infrastructure. They argue it creates uncertainty about these investments and the use of their assets, creating a barrier to investing in new infrastructure or repurposing existing infrastructure. We did not find clear evidence indicating that the hydrogen market will function better when the ITO model will be excluded. Therefore, **we consider regulatory alignment with the gas (and electricity) market to be preferential over the preferred OU model.** This prevents imposing forced unbundling for operators that want to offer hydrogen network services.

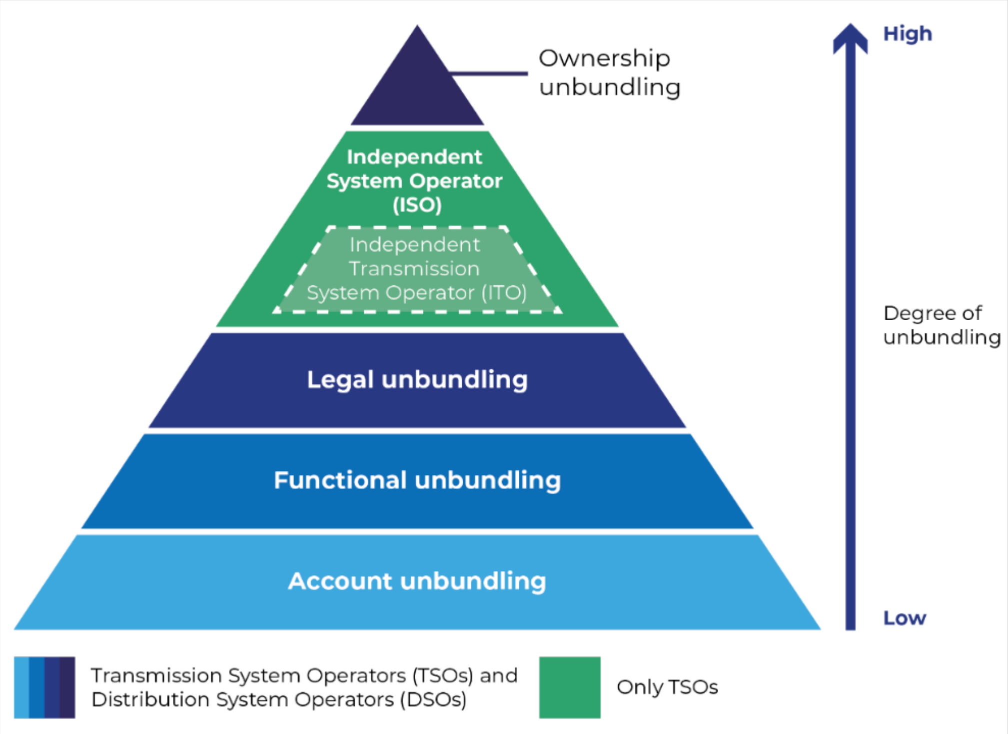
2.1. The use of unbundling rules in the gas market

2.1.1. Unbundling rules in the Third Energy Package

As described in the previous chapter, the Third Energy Package considerably reinforced unbundling rules compared to the Second Energy Package[78]. Unbundling rules require energy supply and generation to be separated from the operation of transmission or distribution networks. The objective of the rules is to encourage fair competition. The regulation covers TSOs[79] and DSOs[80] with different unbundling rules for the respective operators. The rules governing unbundling provide flexibility to the Member States in deciding how to implement the provisions. Section 2.1.2 provides an overview of how unbundling rules are implemented across the EU.

In general, ownership unbundling, which is the highest degree of unbundling, is required for TSOs. In comparison, unbundling requirements are less strict for DSOs and depending on the situation require legal, functional or account unbundling. Figure 2.1 visualises the different types of unbundling and their level of strictness.

Figure 2.2: Degrees of unbundling



Source: Author's elaboration based on Florence School of Regulation, 2020: Unbundling in the European electricity and gas sectors.

[78] The Second Energy Package as adopted in 2003 contained the second electricity Directive 2003/54/EC, the second gas Directive 2003/55/EC and Regulation (EC) No 1228/2003 on conditions for access to the network for cross border exchanges in electricity.

[79] A TSO is a natural or legal person who carries out the function of transmission and is responsible for operating […] and for ensuring the long-term ability of the system to meet reasonable demands for the transport of gas (see: Gas Market Directive 2009/73/EC).

[80] A DSO is a natural or legal person who carries out the function of distribution and is responsible for operating […] and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of gas (see: Gas Market Directive 2009/73/EC).

The major terms related to the unbundling rules, their different aspects, as well as different options for implementation are described further in Box 2.1 below.

Box 2.2: Unbundling terminology and rules

Vertical unbundling means that the vertically integrated companies in the energy system, i.e. different parts of the supply chain such as energy or gas generation, transmission and distribution, have to be divided to separate entities:

- **Management and accounting unbundling** is the most basic level of unbundling meaning that the accounts of transmission and/or distribution activities have to be separated from other activities.
- **Functional unbundling** is a higher degree of unbundling as it requires the network and competitive activities to be separated into different, independent units.
- **Legal unbundling** requires establishing a separate legal entity for network activities.
- **Ownership unbundling (OU)** is the highest degree of unbundling, no energy supply or generation company is allowed to hold a majority share or interfere in the work of a transmission or distribution system operator. The default option in EC regulation is the OU, both for the Third Energy Package and the Hydrogen and Decarbonised Gas Package.

Unbundling for TSOs, according to the Third Energy Package, must take place through **OU** or in one of the following two models, depending on the preferences of each Member State:

- **Independent system operator (ISO):** energy supply companies may still formally own gas or electricity transmission networks but must leave the entire operation, maintenance, and investment in the grid to an independent company.
- **Independent transmission system operator (ITO):** energy supply companies may still own and operate gas or electricity networks but must do so through a subsidiary, and all important decisions must be taken independent of the parent company.
    - **ITO+:** If the transmission system belonged to a vertically integrated undertaking (VIU) at the time of the Third Energy Package entering into force, and arrangements to guarantee more effective independence of the transmission system operator than ensured by the specific provisions of the ITO model were in place, a Member state could choose not to apply the three main unbundling models.

DSO unbundling requirements consist of legal, functional and account unbundling requirements. Provisions are less strict compared to TSOs since DSOs with less than 100,000 customers can be exempted from legal and functional unbundling requirements, yet accounting unbundling is required. Even for the DSOs serving more than 100,000 customers, the unbundling rules are less strict and comparable with the rules placed on an ITO. To ensure different levels of unbundling, the regulation includes, for example, an obligation to avoid confusion for consumers between the DSO and the supply company and a requirement for financial independence in the form of DSOs having enough resources to maintain and extend the existing infrastructure.

Even though traditionally unbundling in the energy sector is always vertical, **horizontal unbundling** introduces competition through the introduction of several entities in the sector with the same responsibilities (e.g. in the gas generation or wholesale and retail gas markets):

- **Legal separation** is the most basic form of horizontal unbundling meaning that any undertaking that is active as an hydrogen operator as well as in transmission or distribution of electricity or natural gas should at least be separated in their legal form.
- **Management and accounting unbundling** requires gas system operators that ought to also become hydrogen system operators keep separate accounting between the infrastructures to ensure transparency and separate tariff-setting.

Sources: Florence School of Regulation, 2020: Unbundling in the European electricity and gas sectors; World Bank, 2020, Rethinking Power Sector Reform In The Developing World; United States Agency for International Development Energy Investment Activity (US AID EIA), 2019: Report on unbundling of the natural gas market in Bosnia and Herzegovina.

In addition to the unbundling rules, the Third Energy Package introduced a certification process that is to be conducted by NRAs. This certification process is conducted by NRAs allowing them to assess the independence of the network operators[81]. NRAs are allowed to put additional requirements for the certification process and some Member States authorities have done it for certain processes.

2.1.2. Implementation of the unbundling rules in the Member States

Since the regulatory framework for gas allows some differences in the implementation of the unbundling rules, there is some variation across the Member States. Some smaller Member States, namely Cyprus, Luxembourg and Malta, do not have to comply with the electricity or gas TSO unbundling rules. In addition, Estonia, Latvia, Finland and other Member States were considered an emergent market or as having significant problems in a geographically limited area and therefore were able to benefit from exempting their gas TSOs from applying the unbundling provisions for a temporary period.

In terms of implementing the **unbundling requirements for TSOs**, a survey[82] among the NRAs in charge of assessing the independence of network operators identified a trend in the Member States supporting further privatisation of their TSOs and increasing participation of financial funds, as well as a trend in increasing third-country participation in EU TSOs. Further to this, the survey found a change in business models as some major European TSOs, such as France and Great Britain, moved from an ITO model to an OU model by divesting their shares. Based on this CEER assessed that **the Third Energy Package gives sufficient flexibility to TSOs to reorganise and adapt their business to unbundling requirements**. Additional unbundling requirements put on TSOs by NRAs are also compliant with EU legislation, though in some cases the processes were judged as burdensome.

The survey assessed also the **status of DSO unbundling** and found differences in the application of DSO unbundling in the Member States. For example, the Netherlands is the only Member State where full OU for DSOs is required by law. In the Flanders region of Belgium, while not requiring OU, in practice DSO has also been fully unbundled there.

81 CEER, 2019, *Implementation of TSO and DSO Unbundling Provisions. Update and Clean Energy Package Outlook. CEER Status Review*. Available at: https://www.ceer.eu/documents/104400/-/-/f69775aa-613c-78a5-4d96-8fd57e6b77d4.

82 Ibid.

In contrast, Malta has been exempted from DSO unbundling rules. The DSO landscape is highly heterogeneous as not only the different implementations of regulation but also the number, size, technical characteristics and activity profiles of DSOs vary a lot. However, in contrast to the consolidating trend for TSOs, the number of DSOs has remained mostly stable.

In 2020, 25 Member States implemented the OU model while in 10 Member States also the ITO framework and in two the ISO framework was used[83]. For a full overview of the implementation of unbundling rules in the Member States for TSOs and DSOs, see Table 2.1 below. The unbundling regimes for TSOs and DSOs are presented in the second and fourth columns respectively. It furthermore provides an indicative overview of the number of transmission and distribution operators in each Member State.

Table 2.1: Implementation of TSO and DSO unbundling rules in the Member States

	TSO unbundling	Number of gas TSOs**	DSO unbundling	Number of gas DSOs***
Austria	One gas ISO (2012)	1		20
Belgium	OU*	2	Flemish region: in practice full OU	14
Bulgaria	ITO	1		
Croatia	OU*	1		35
Czech Republic	ITO*	1		73
Denmark	OU*	1		6
Estonia	OU*	1		25
Finland	OU	1		25
France	TSO Teréga changed from an ITO to OU in 2014, the other TSO is ITO	2	The parent company is a holding with two subsidiaries: one for the production/supply activity and the other one is in charge of electricity distribution	25
Germany	OU + ITO*	12		714
Greece	Changed from the ITO model to the OU model	1		4
Hungary	ITO	1		10
Italy	ITO* in 2016 changed to OU****	3		226
Ireland	Changed from an ITO to an OU in 2016	1		
Latvia	OU	1		1
Lithuania	OU*	1		6
Luxembourg	Exempted from the rules	1		2
Malta	Exempted from the rules		Exempted from the rules: internal accounting level only	
Netherlands	OU	2	OU	9

[83] European Commission, 2021c, *Evaluation Report on the Gas Directive and the Gas Regulation*, SWD(2021) 457 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021SC0457&from=EN.

	TSO unbundling	Number of gas TSOs**	DSO unbundling	Number of gas DSOs***
Poland	ISO + OU*	1		51
Portugal	OU*	1		11
Romania	ISO*	1		49
Slovakia	ITO*	1		1
Slovenia	ITO*	1		16
Spain	ISO + OU*	2		18
Sweden	ISO + OU*	1		6
Cyprus	Exempted from the rules	1		1
Total		44		1348

Note: * CEER, 2016; ** Members (Estonia: associated partner) in ENTSOG, https://www.entsog.eu/members; *** CEER, 2016, numbers from 2015; **** based on an interview with CEER; Other sources: CEER, 2016; CEER, 2019.

2.2. The impact of unbundling rules on gas operators and gas and hydrogen infrastructure

This section first analyses the impact of the current unbundling rules on gas operators and gas infrastructure. It then assesses the opportunities and barriers to the uptake of hydrogen infrastructure and finally draws lessons on the potential impact of the revised unbundling rules on the uptake of hydrogen and renewable gas infrastructure.

2.2.1. Development of gas infrastructure after the introduction of unbundling rules

In 2009 when the Third Energy Package was adopted it aimed to liberalise and build a competitive EU market for gas and electricity. It aimed at completing the internal market for electricity and gas by harmonising the different processes of energy systems and markets in the EU[84]. The main aim was **to provide access to existing infrastructure and not to provide incentives for the development of new transmission infrastructure**.

Particularly, regarding OU, several studies find potentially positive effects of stricter vertical unbundling rules[85] on gas markets. OU model can lead to lower energy prices and stronger incentives for investments and cross-border transmission capacities. In terms of choosing ownership unbundling as the main, preferred option in the Third Energy Package, the European Commission mentioned in its proposal the effectiveness of separating the transmission from other stages of the value chain. Particularly, two main benefits are mentioned: a) decreasing the TSOs incentive to treat affiliated and independent generators and/or retail companies differently, and b) increasing the incentives to invest in cross-border transmission capacities[86].

[84] EPRS Briefing, 2021, *Revision of the third energy package for gas: Decarbonising the gas market*. Available at: https://www.europarl.europa.eu/RegData/etudes/BRIE/2021/699464/EPRS_BRI(2021)699464_EN.pdf.

[85] Pollitt, M.G., 2007, *Ownership Unbundling of Energy Networks*. Available at: https://www.econstor.eu/bitstream/10419/42002/1/555590089.pdf.

[86] The original memorandum by the European Commission is no longer available online, quotations and conclusions of it were used to retrieve the reasoning. Sources: Pollitt, M.G., 2007, Ownership Unbundling of Energy Networks; Haucap, J., 2007, The costs and benefits of ownership unbundling. In Intereconomics, ISSN 0020-5346, Springer, Heidelberg, Vol. 42, Iss. 6, pp. 292-301; 301-305. Available at: https://www.econstor.eu/handle/10419/41975.

The evaluation of the Third Energy Package for Gas found that "the reinforcement of unbundling requirements has had a positive effect on the competition with new players entering the gas market" adding however that "in some Member States the incumbent still holds a dominant position"[87]. Thus the **unbundling rules were vital in creating open and fair retail markets and consumer protection**. Overall, while creating certain administrative costs for undertakings and regulators, these have not been perceived as too heavy and seem to be outweighed by the benefits of increased competition and welfare gains.

For the above reasons and to create regulatory clarity, the Commission proposes to **keep OU as the main option in the current proposal for the Revised Third Energy Package**.

Additionally, in response to the gas crises of 2006 and 2009, the EU adopted the first security of gas supply Regulation No 994/2010 in 2010. Its main goal was to reinforce the security of the gas supply and diminish the impacts of interruptions of the gas supply. It furthermore introduced the principle of solidarity, where the Member States were expected to help each other in the event of a serious gas supply crisis to avoid the possibility of any disruptions for European households.

As such, **it is argued that the EU was successful in creating a single competitive gas market and gas infrastructure**. This is confirmed in the interviews, as the general opinion from the stakeholders is that the unbundling regulation has been working well. The framework allowed for sufficient flexibility through derogations so emerging markets could develop[88]. The EU gas market constitutes more than 200,000 km of transmission pipelines and 2,000,000 km of distribution networks[89]. The support study for the evaluation of the TEN-E found that there is no need for further development of gas networks. This study, however, does not consider recent events and the need to diversify the gas supply potentially by establishing new gas interconnectors with third countries or retrofitting existing infrastructure for hydrogen transport.

In the current 2022 situation, a new gas supply crisis has emerged with Russia's invasion of Ukraine. The focus on the security of supply shifted from securing the proper market-driven allocation of financial resources to securing minimal physical gas supply volumes. This crisis is however driven by political rather than economic considerations and is therefore independent of or beyond the market. Though the consequences are felt by European households and businesses, for one the structurally high energy prices. As a result, some question the functioning of the energy and energy-related markets (e.g. ETS). In the short term, the Commission proposed emergency intervention actions to tackle high energy prices[90]. Initiatives such as REPowerEU and the European Gas Demand Reduction Plan aim to tackle the risks and costs of this gas supply crisis **by investing in additional infrastructure and reducing demand**. The role of the gas infrastructure in ensuring energy supply is further discussed in Chapter 4.

87 European Commission, 2021c, Evaluation Report on the Gas Directive and the Gas Regulation, SWD(2021) 457 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021SC0457&from=EN.

88 Barnes, A., 2020, Can the current EU regulatory framework deliver decarbonisation of gas? Available at: https://www.oxfordenergy.org/publications/can-the-current-eu-regulatory-framework-deliver-decarbonisation-of-gas/#:~:text=The%20framework%20will%20not%20deliver,transition%20to%20a%20decarbonised%20future.

89 ACER, 2021(a), key facts about gas in the EU. Available at: https://acer.europa.eu/en/Gas/Documents/ACER_FACT-SHEETS_2021-07_02.pdf.

90 See: https://ec.europa.eu/commission/presscorner/detail/en/IP_22_5489.

2.2.2. Expected impact of proposed vertical unbundling rules

This subsection will analyse the expected impacts of the proposed vertical unbundling rules in the revised Third Energy Package on the natural gas and hydrogen undertakings including production, transmission, distribution, supply, purchase and storage.

The European Commission argues that the "future regulatory framework can build upon the existing principles that regulate the current gas market", due to the similarities between the current gas market and the expected hydrogen market[91]. Though not all stakeholders share the same point of view, for example, ACER is concerned about the role of TSOs in hydrogen production, while ENTSOG promotes it[92]. Thus highlighting potential disagreements between TSOs and regulators when dealing with any future unbundling of hydrogen production or supply from transportation.

With the introduction of the 'Hydrogen and Decarbonised Gas Market' package, the Commission aims to develop competitive hydrogen markets based on models that have been applied to the natural gas and electricity markets. The proposal includes the introduction of market and network regulation in a phased approach, with the key cut-off date being 31 December 2030. After this date, exceptions particularly those entailing TPA, unbundling and tariff structures will be removed and a strict regulatory regime will be installed. With the proposal, the Commission aims to set a clear regulatory framework for the development of a hydrogen market.

Chapter IX of the proposed revised Gas Directive entails the unbundling of hydrogen networks. Specifically, Article 62 indicates that ownership unbundling will be the default rule for hydrogen network operators and the **ITO model is no longer allowed after the cut-off date of 31 December 2030**. The proposals of the Commission do not make a distinction between the distribution and transmission of hydrogen. The unbundling exemptions for certain DSOs under the current Third Energy Package would no longer be applicable under the new proposals. This would mean that both TSOs and DSOs that do not apply the OU or ISO model are forced to apply it if they want to offer hydrogen distribution or transportation services.

According to the European Commission, **the exclusion of the ITO model should give clear expectations of how the hydrogen market ought to look in the future**. The development of a hydrogen market is something completely new and setting the standard follows the Commission's goal of creating a well-regulated competitive and functioning hydrogen market. The Commission argues that there are no or limited legacy operators since it is a new market and therefore for a system-level efficient operation of the hydrogen system, it would be best to go with the OU and possibly the ISO model as target rules in the longer term while providing some flexibility while the market is maturing[93]. Another reason for ruling out the ITO model would be diminished regulatory oversight costs. The exception under 2030 aims to attract investments, particularly from the private sector to develop cost-effective infrastructures.

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[91] Barnes, A., 2020, *Can the current EU regulatory framework deliver decarbonisation of gas?* Available at: https://www.oxfordenergy.org/publications/can-the-current-eu-regulatory-framework-deliver-decarbonisation-of-gas/#:~:text=The%20framework%20will%20not%20deliver,transition%20to%20a%20decarbonised%20future.

[92] Heather, P. (2022) A Series of Unfortunate Events - Explaining European Gas Prices in 2021: The role of the traded gas hubs.

[93] As stated by Ms Kitti Nyitrai, Head of Unit Decarbonisation and sustainability of energy sources, DG ENER at Hydrogen Europe's Hydrogen Talk: Assessing the hydrogen and decarbonised gas package, 05 October 2022, available at: https://hydrogeneurope.eu/h2-talks/.

Criticism is often based on the conclusion that **the current three models are perceived to work well**, by TSOs, regulators and the Commission[94]. As the hydrogen network is expected to be similar to gas networks in structural features, many stakeholders do not see benefits in cutting off the ITO model. ENTSOG and regulators see costs and risks regarding such provision. Implementing the required organisational changes would take time and resources. ACER and CEER recommend[95] a flexible and gradual implementation of regulatory principles. While OU is accepted as the target model, they stress the immaturity of the hydrogen market and infrastructure needs.

Notably, electricity and **gas network operators that follow this ITO model raise concerns about the exclusion of the model**, and its effects on the gas infrastructure as well as the uptake of hydrogen infrastructure[96]. Network operators currently operating under the ITO model that are interested to invest in hydrogen infrastructure will be forced to either sell their hydrogen infrastructure assets or switch to the OU or ISO model after 2030. This requires organisational changes that are costly and take time. Network operators fear that this will distract them from rolling out a hydrogen network. Selling (or transferring under the ISO model) this infrastructure results in a loss of synergies with operating methane as well as hydrogen infrastructures. Moreover, as the uptake of hydrogen in the mid-term is highly uncertain, this would significantly harm the incentive to invest in repurposing infrastructure and constructing new infrastructure in the first place. Hence, this would pose a threat to the overall development of a hydrogen network.

In Germany for example the ITO model is widely used. German operators account for more than half of the ITOs in Europe and therefore oppose the 2030 cut-off date for applying the ITO model. They argue it would exclude a large share of TSOs and DSOs from transporting and distributing hydrogen and would risk the successful deployment of a hydrogen backbone infrastructure. Furthermore, applying the OU model would require the shareholders of these TSOs to divest their shares in energy production and supply, or shareholders to divest their shares in the TSO and hydrogen network operator. It is arguable whether the Commission's preference for the OU model justifies these consequences on ownership rights.

Thus, the proposed changes in vertical unbundling models impact gas undertakings differently. Notably, network operators that currently operate under the ITO model are negatively impacted by the proposed changes if they want to offer hydrogen distribution or transportation services. Network operators that currently operate under the OU or ISO model are not impacted by the proposal to limit vertical unbundling models. **Other gas undertakings, such as firms responsible for the production, storage and sale of gas that wish to expand their services to hydrogen are expected to benefit from the proposal**. Implementation of the Third Energy Package successfully promoted competition and removed conflicts of interest between producers and suppliers on the one hand and transmission system operators on the other hand. In its impact assessment, the Commission argues it furthermore increased liquidity and competition leading to fairer prices on wholesale markets and enhanced

[94] European Commission, 2021, Staff working document SWD(2021)457 final, Evaluation report accompanying the Proposal for a Directive and Regulation of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast).

[95] ACER & CEER, 2021, Position paper on the key regulatory requirements to achieve gas decarbonisation.

[96] FNB Gas, 2022, Position on the set of proposals adopted by the European Commission on common rules for the internal markets in renewable and natural gases and in hydrogen.

cooperation between TSOs[97]. The proposal expands these rules to hydrogen, thus it is likely these benefits will also apply to the hydrogen market.

Since the start of the liberalisation of the energy market, the European Commission has expressed a preference for the implementation of the OU model, but lacked in providing clear arguments on why OU is considered the favourable model. Ownership unbundling can be seen as an increasingly implemented model on a transmission level[98]. When competition and non-discriminatory market access are the key priorities, ownership unbundling is the most consistent regulatory measure[99]. Though, **convincing evidence that supports the preference for full ownership unbundling (or any specific form of unbundling) is very thin at best**. Limited studies have been conducted on the effects of ownership unbundling and most of the available studies focus on the electricity market. Pollitt[100] argues that some studies indicate there are positive effects of the unbundling of electricity transmission networks, but the evidence is circumstantial and successful cases simultaneously implemented other reform steps such as pro-competitive policies. Less research has been done on the gas market, but the available research shows no positive effects, including at the transmission level. Growitsch and Stronzik[101] find that ownership unbundling has no impact on natural gas end-user prices, while more moderate legal unbundling reduces them significantly.

Furthermore, the benefits on a distribution level are more diffuse. Nillessen and Pollitt[102] argue that two case studies in the Netherlands and New Zealand show that ownership unbundling did not increase network quality and retail competition, but there were significant one-offs and structural costs involved in the implementation of the model. Arguably, TSOs and DSOs that currently operate under the ITO model are faced with similar costs if they wish to invest in hydrogen infrastructure.

There is no clear evidence indicating that the gas market or the hydrogen market will function better without the ITO model. However, excluding the ITO model for hydrogen network operators would result in different rules for the gas (and electricity) and hydrogen markets. The European Commission justifies this by the fact that the hydrogen market still needs to develop, and there are no or limited legacy operators at this stage and therefore advocates for simplifying the rules. Nevertheless, these rules for the hydrogen market do have an impact on current gas network operators. This cannot be ignored. There is insufficient evidence that the separate treatment of gas and hydrogen results in clear benefits. At the same time, the costs of imposing OU are clear and certain. For this reason, **we consider regulatory alignment to be preferential**. This also likely requires a distinction between the transmission and distribution of hydrogen.

Table 2.2 provides an overview of the main arguments in favour of and against the proposal to exclude the ITO model in the revised Gas Directive and to make the OU model the default option.

[97] European Commission, 2021, SWD(2021) 457 final, Evaluation report accompanying the Proposal for a Directive and Regulation of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast).

[98] Chawla, M. and Pollitt, M. 2013. Global trends in electricity transmission system operation: Where does the future lie?

[99] European Commission, Directorate-General for Energy, Cihlar, J., Krabbe, O., Deng, Y., et al., Assistance to the impact assessment for designing a regulatory framework hydrogen, Publications Office, 2021.

[100] Pollitt, M. 2008. The argument for and against ownership unbundling of energy transmission networks.

[101] Growitsch, C., Stronzik, M. 2014. Ownership unbundling of natural gas transmission networks: empirical evidence.

[102] Nillesen and Pollitt, 2021, Ownership unbundling of electricity distribution networks.

Table 2.2: Key argumentations concerning the exclusion of the ITO model

Arguments in favour of excluding the ITO model	Arguments against excluding the ITO model
The current proposal sets **a clear framework for the future H2 market**	All (OU, ISO, ITO) **models have been working well**, according to both regulators' and the Commission's assessments
OU is the most consistent measure in terms of **competition and non-discriminatory market access**	**Exclusion has different impacts among the Member States**, as some have a larger share of ITO network operators
Diminished regulatory **oversight costs**	**Loss of synergies** between methane and hydrogen operation in current ITO models
Management of (unbundled) parts of the company may be subject to a **clearer focus**	**No incentives for investment** in **H2 infrastructure** for current ITO network operators
	Exclusion of current ITO network operators from the H2 business

Source: Authors' own elaboration. Pollitt [103] lists more theoretical arguments in favour of ownership unbundling in relation to other models.

2.2.3. Expected impact of proposed horizontal unbundling rules

The European Commission argues in the proposal that the joint operation of hydrogen networks and gas and electricity networks can create synergies that would benefit the development of a hydrogen infrastructure and the operation of the energy system as a whole. At the same time, the Commission stresses the need for transparency. The regulatory framework should allow Member States to choose to direct revenues from the gas system to finance hydrogen infrastructure, but this needs to be transparent and monitored. Furthermore, it should be ensured that levies are not collected from cross-border users, but from domestic users. Hence why the European Commission considers horizontal unbundling to be a crucial element for regulators to chase and control this. Horizontal unbundling is endorsed by key stakeholders such as ACER and CEER as well as ENTSOG. However, these stakeholders have a different position in the translation to horizontal unbundling of network operators.

ACER, CEER and ENTSOG consider a legal separation between hydrogen network operators and gas network operators as proposed in Article 63 not proportionate to the requirement of horizontal unbundling. They argue accounting unbundling, subject to NRA approval, ensures sufficient transparency to trace any financial transfer between natural gas and hydrogen, thus benefitting all gas undertakings.

Synergies can mostly be created by the existing technical expertise and personnel that have been built up in current network operators. Furthermore, repurposing existing infrastructure and constructing new hydrogen infrastructure will be more efficient if coordinated in an integrated manner. Legal unbundling would harm these synergies, for example as network operators would have to compete for skilled labour, and necessary coordination and communication will be separated.

[103] Pollitt, M. 2008. The argument for and against ownership unbundling of energy transmission networks.

2.2.4. Opportunities and barriers to the uptake of hydrogen infrastructure

Currently, natural gas network operators are subject to EU regulations in the natural gas market. Under the current framework, gas market rules apply therefore neither to newly built hydrogen networks nor to natural gas networks that could be retrofitted in the future to transport pure hydrogen. Under this current regime, hydrogen transport infrastructure has been built in the EU, albeit only small networks exist and are often privately owned. Networks are currently often centralised around industrial centres such as ports (i.e. Port of Rotterdam).

However, given the current need for hydrogen infrastructure identified in the Green Deal and most recently in RePowerEU, infrastructure development has not been fast enough. This was also identified as one of the shortcomings found in the evaluation: the current regulatory framework does not support the deployment of hydrogen, dedicated hydrogen infrastructure or the repurposing of natural gas networks for the transport of hydrogen[104].

Some of the barriers to hydrogen infrastructure investment/uptake include:

- **Differences between the Member States** – uncoordinated and weak cross-border integration and network development[105];
- **Regulatory uncertainty** as existing unbundling rules create uncertainty for current operators and producers to invest in hydrogen[106];
- **Market failures** associated with an investment in dedicated transport networks; and
- **Existing rules do not provide incentives** for the decarbonisation of the energy system including renewable and low-carbon gas[107].

As mentioned previously, the evaluation of the Gas Directive and Gas Regulation found that unbundling requirements had a positive effect on the competition with new players entering the gas market[108]. Despite being an emerging market, regulating the hydrogen and decarbonised gas market in line with the existing regulatory framework could not only create certainty but also would make sense as hydrogen and decarbonised gas have similar economic characteristics to the existing natural gas market[109].

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[104] Barnes, A., 2020, *Can the current EU regulatory framework deliver decarbonisation of gas?* Available at: https://www.oxfordenergy.org/publications/can-the-current-eu-regulatory-framework-deliver-decarbonisation-of-gas/#:~:text=The%20framework%20will%20not%20deliver,transition%20to%20a%20decarbonised%20future.

[105] European Commission, 2021c, Evaluation Report on the Gas Directive and the Gas Regulation, SWD(2021) 457 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021SC0457&from=EN.

[106] European Commission, 2019a, Directorate-General for Energy, Galano, C., Grinsven, A., Kampman, B., et al. *Potentials of sector coupling for decarbonisation: assessing regulatory barriers in linking the gas and electricity sectors in the EU*: final report, Publications Office. Available at: https://op.europa.eu/en/publication-detail/-/publication/60fadfee-216c-11ea-95ab-01aa75ed71a1/language-en.

[107] European Commission, 2021c, Evaluation Report on the Gas Directive and the Gas Regulation, SWD(2021) 457 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021SC0457&from=EN.

[108] European Commission, 2021c, Evaluation Report on the Gas Directive and the Gas Regulation, SWD(2021) 457 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021SC0457&from=EN.

[109] CEER, 2018, *Study on the Future Role of Gas from a Regulatory Perspective*. Available at: https://www.ceer.eu/documents/104400/-/-/6a6c72de-225a-b350-e30a-dd12bdf22378.

When comparing the gas market to the hydrogen market, there are some key characteristics to be considered:

- **Maturity**: Hydrogen production and infrastructure are only emerging and not as established as natural gas was during the implementation of the Third Energy Package and too strict regulation may prevent investments[110];

  If it is feasible to have multiple production sites with a variety of owners, each of which has access to markets for trade with retail suppliers, then the market structure may resemble the existing natural gas markets[111];

- **End users**: End users are less integrated and in contrast to natural gas, growth is not driven by demand, but by regulation and policy objectives. It is unclear who the end users will be and if hydrogen is to be used beyond the hard-to-abate sectors, such as long-distance and heavy transport, including aviation and shipping, iron and steel production, and chemicals manufacture.[112] These sectors find it harder to reduce their CO_2 emissions, thus relying on hydrogen in greening their processes. Other sectors might turn to other solutions that might be more (economically) viable, such as electrification;

- **Costs**: The production costs for hydrogen and in particular renewable hydrogen have been less competitive in economic terms compared to other energy sources. However, the increasing prices for natural gas have made investments in hydrogen more interesting, and renewable hydrogen is expected to become very competitive compared to non-renewable hydrogen.[113] However, on top of this, come also the high costs of transporting, storing and distributing hydrogen as hydrogen has a low viscosity. For example, the potential risk of hydrogen leakage has to be considered when developing the infrastructure.[114] Research is therefore investigating converting hydrogen into hydrogen-based fuels and feedstocks (ammonia, synthetic methane, synthetic liquid fuels) to facilitate storage, transport and in some cases use by end users[115];

- **Standardisation**: There is a lack of international standards and regulations regarding the production, transport and use of hydrogen, which limits the diffusion of hydrogen and its overall potential.[116] In this regard, however, the EU provides a leading example with its proposed regulation and could lead the way forward for international rules for hydrogen;

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[110] Barnes, A., 2020, *Can the current EU regulatory framework deliver decarbonisation of gas?* Available at: https://www.oxfordenergy.org/publications/can-the-current-eu-regulatory-framework-deliver-decarbonisation-of-gas/#:~:text=The%20framework%20will%20not%20deliver,transition%20to%20a%20decarbonised%20future.

[111] Barnes, A., 2020, *Can the current EU regulatory framework deliver decarbonisation of gas?* Available at: https://www.oxfordenergy.org/publications/can-the-current-eu-regulatory-framework-deliver-decarbonisation-of-gas/#:~:text=The%20framework%20will%20not%20deliver,transition%20to%20a%20decarbonised%20future.

[112] European Roundtable on Climate Change and Sustainable Transition, 2022, *The hydrogen and decarbonized gas market package – focus on hydrogen*, ERCST FEEDBACK. Available at: https://ercst.org/ercstfeedback-to-the-h2-and-gaspackage-proposals/.

[113] For comparison between costs of different types of hydrogen, see for example, S&P Global (2022) Interview: Sustained high European gas prices making green hydrogen competitive – ETC. In some countries, there are signs that green hydrogen has become less costly to produce compared to natural gas, see Hycap Group, July 2022, *Green hydrogen cheaper than natural gas in Europe boosts investment*. Available at: https://www.hycapgroup.com/green-hydrogen-cheaper-than-natural-gas-in-europe-boosts-investment/.

[114] For more information on the risk of leakage, technologies to prevent it, and recommendations, see Fan et al., 2022, Hydrogen leakage: A potential risk for the hydrogen economy, Center on Global Energy Policy at Columbia University SIPA. Available at: https://www.energypolicy.columbia.edu/research/commentary/hydrogen-leakage-potential-risk-hydrogen-economy#:~:text=In%20the%20future%2C%20leaked%20hydrogen,not%20exist%20at%20scale%20today.

[115] Scita, R. et al, 2020, *Green Hydrogen: the Holy Grail of Decarbonisation? An Analysis of the Technical and Geopolitical Implications of the Future Hydrogen Economy*, Working Paper, No. 013.2020, Fondazione Eni Enrico Mattei (FEEM). Available at: https://www.econstor.eu/bitstream/10419/228789/1/ndl2020-013.pdf.

[116] Ibid.

- **Complex value chains**: The hydrogen value chain is complex and several alternative options exist for production, transportation and end-use. The characteristics of the end-users will influence the transportation of hydrogen (i.e. requirements on hydrogen purity); and
- **Type of investment needed**: As discussed previously, energy infrastructure requires a high capital intensity, making it a risky investment for private investors, especially when much of the supporting infrastructure, production and demand need still to be developed. In light of this, public funding (see Section 2.2.3) has been provided in the past to natural gas infrastructure and will be extended to hydrogen infrastructure to facilitate these large-scale investments.

Furthermore **unbundling was introduced to provide access to existing infrastructure and not specifically to incentivise building new projects**. Exemptions for gas infrastructure investments were (and will be) not just important for emerging markets, but also for new infrastructure in mature markets. In the gas market, few investments in the main transport networks were necessary, but exemptions were given to other types of infrastructure like LNG terminals, storage facilities and interconnectors. In the hydrogen market, similar exemptions for transport would probably be needed.

More specifically, CEER highlights that specific issues may emerge concerning the involvement of the regulated network operators in contestable activities such as power-to-gas (P2G) infrastructure for hydrogen production. "While the involvement of such regulated entities may not be necessarily denied, it should reflect the requirements of the unbundling provisions, i.e. network operators may get involved in the operation of such infrastructure but may not get involved in any way in the production or supply of natural gas. There might be individual cases where regulators will need to look at the potential benefits from the integration of P2G installations in the regulated network assets, particularly when the installations and their direct control have an essential role in the secure network operation. For example, in areas with large RES generation, P2G installations could allow electricity network operators to avoid curtailment of RES installations in times of excess supply. Similarly, natural gas network operators could make use of the methanation part of P2G installation to convert hydrogen into synthetic gas and to ensure secure support of larger green gas volumes"[117].

[117] CEER, 2018, *Study on the Future Role of Gas from a Regulatory Perspective*. Available at: https://www.ceer.eu/documents/104400/-/-/6a6c72de-225a-b350-e30a-dd12bdf22378.

3. DEVELOPING THE EU HYDROGEN BACKBONE

KEY FINDINGS

Currently, hydrogen is mainly produced and consumed in industrial clusters. TSOs and DSOs do not operate existing networks as supply and demand occur on-site and transportation over longer distances is non-existent. However, TSOs do have an interest in stepping into the hydrogen market. The key initiative by European energy infrastructure operators to connect these clusters and support the uptake of hydrogen is the **European Hydrogen Backbone (EHB)**. The EHB would serve as a base for a European hydrogen network by 2030 and beyond. It should however be noted that the EHB is not based on a thorough network planning exercise, but showcases based on cost estimates of infrastructure operators what would be achievable by 2030 and 2040. A **European hydrogen network would however likely be smaller than the natural gas network** since it would be mainly dedicated to serving industry and not also households.

A hydrogen network could be deployed through the repurposing of natural gas infrastructure and the blending and construction of new infrastructure. **Repurposing existing gas networks is estimated to be the most cost-efficient option**. Repurposing comes however with its challenges as in particular it would need to happen gradually while also ensuring that crucial natural gas flows can still flow while also not delaying the deployment of hydrogen unnecessarily. In creating a hydrogen network, repurposing needs to be supported by constructing new infrastructure and, to support the initial uptake of hydrogen in areas without dedicated infrastructure, blending hydrogen with natural gas. The speed of the transition depends on several factors, such as permitting and regulatory processes, but also the timeframe in which the current infrastructures can be repurposed.

The EU Hydrogen and Decarbonised Gas Market Package provide **the base regulatory framework** for the uptake of renewable hydrogen and the development of an EU Hydrogen network. Construction of a network as outlined in the European Hydrogen Backbone will take time and not all the capacity will be used from the start. **Revenues from user tariffs will be insufficient during the first years** or otherwise put an insurmountable burden on the initial users of hydrogen, and other financing options are needed.

The proposed revision of the Gas Regulation introduces **limited financial transfers between gas and hydrogen infrastructure** to finance hydrogen networks, which in turn could however put the costs of the decarbonisation of industry on households. Therefore, other initiatives and support mechanisms remain crucial to create the right incentives and guarantees for the private sector to invest in hydrogen infrastructure. Supporting initiatives include European and national funding mechanisms and other instruments Projects of Common Interest for hydrogen under the revised TEN-E Regulation and the Important Projects of Common European Interest.

3.1. Status quo of the hydrogen infrastructure

This section presents the current situation of hydrogen infrastructure in Europe, and how the current and future hydrogen supply is linked to the natural gas network.

The **production of hydrogen** is an essential component of hydrogen uptake, and there are multiple methods to produce hydrogen. Box 3.1 provides an overview of the various hydrogen production methods. The EU Hydrogen and Decarbonised Gas Market Package aim to enhance the uptake of renewable hydrogen, also known as green or decarbonised hydrogen. Targets mentioned in REPowerEU include the production of 10 million tonnes of renewable hydrogen by 2030. In terms of the exact definition of renewable hydrogen, the debate is ongoing.

Box 3.3: Hydrogen production[118] [119]

> Hydrogen is not an energy source per se but serves as an energy carrier, meaning that its production requires energy. Hydrogen can be produced using various forms of energy, which determines its level of decarbonisation. Today, production of hydrogen is industry-based and consists mainly of **grey hydrogen** and **black hydrogen**. Grey hydrogen and black hydrogen are produced using fossil fuels, namely natural gas and coal, respectively. Furthermore, **blue hydrogen** refers to hydrogen produced using fossil fuels, but the CO_2-emissions of which are captured, utilised and stored (CCUS). This is seen as a low-carbon method and can play a transitional role in scaling up hydrogen production. Finally, **green hydrogen** is produced using renewable electricity, thus being a completely decarbonised form of hydrogen. The Commission targets particularly concern green, renewable-based hydrogen. The most commonly used term by the Commission is **renewable hydrogen**, and thus our report uses that rather than green hydrogen. In addition, most of the hydrogen today (64%) is **produced on-site**, or **as a by-product** of industrial processes (21%). The remaining 15% accounts for centrally produced hydrogen that is delivered to consumers.

There has been a debate about whether it is possible to achieve the EU targets of renewable hydrogen with the current level of renewable energy production. Critics argue that the share of renewable electricity in the overall electricity mix will be limited and will not reach sufficient levels to support the production of renewable hydrogen. They argue the production of renewable hydrogen will increase CO_2 emissions as more electricity needs to be generated by fossil-fuelled power plants[120]. However, the emissions from the energy sector are covered by the Emission Trading System (ETS), which sets a cap on the total amount of GHG emissions in the system.

Additionally, the **transport and distribution of hydrogen** play a key role in decarbonising Europe's energy system. There are two common methods to facilitate the distribution of hydrogen: using pipelines and trucks. In general, pipelines are the most cost-efficient way of transporting gaseous hydrogen given the demand is large enough.

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118 IEA, 2019, *The Future of Hydrogen: Seizing today's opportunities*, available at: https://www.iea.org/reports/the-future-of-hydrogen.

119 European Commission, 2020d, Hydrogen generation in Europe: Overview of costs and key benefits, available at: https://op.europa.eu/en/publication-detail/-/publication/7e4afa7d-d077-11ea-adf7-01aa75ed71a1/language-en.

120 Bellona, 2021, Electrolysis hydrogen production in Europe.

Trucks are more beneficial for both gaseous and liquid hydrogen when the demand is relatively low[121]. Other transport options include importing and exporting hydrogen through marine terminals, including adjusted LNG terminals, shipping or railways.

Currently, the hydrogen supply is mainly located in regional industrial clusters and sectors that are **users of hydrogen**. These are relatively energy-intensive and hard-to-abate sectors. These sectors are expected to account for most of the expected future demand. Today, hydrogen is mostly used in the chemical sector, particularly in the production of plastics and fertilisers. In addition, the transport sector [122], especially trucks, and industries where high temperatures are used in the production of goods are often mentioned as sectors where hydrogen could be utilised. Some argue that hydrogen could, furthermore, be expanded to low-temperature heating and passenger cars, but in the EU it is more likely that these are electrified rather than converted to hydrogen-based in the short- and medium-term.

Hydrogen valleys are European and international industrial clusters where local stakeholders cooperate to facilitate projects to establish a hydrogen value chain [123]. Some of them are ingrained in the local ecosystems, while others have a cross-border nature. Figure 3.1 maps the locations of current European hydrogen valleys, which show geographical concentration in Belgium, the Netherlands and Germany.

121 European Commission, 2020f, Hydrogen generation in Europe: Overview of costs and key benefits. Available at: https://op.europa.eu/en/publication-detail/-/publication/7e4afa7d-d077-11ea-adf7-01aa75ed71a1/language-en.

122 Regarding transport sector, the Commission has set targets for accessible charging and refuelling infrastructure in its Alternative Fuel Infrastructure Regulation (AFIR) proposal[122] which is a central pillar of the Fit for 55 climate package. See European Commission, 2021, *Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the deployment of alternative fuels infrastructure, and repealing Directive 2014/94/EU of the European Parliament and of the Council.* Available at: https://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX%3A52021PC0559.

123 Hydrogen valleys are described as "regional ecosystems that link hydrogen production, transportation, and various end uses such as mobility or industrial feedstock", according to the project by the Fuel Cells and Hydrogen Joint Undertaking and Mission Innovation. The report is available at: https://h2v.eu/analysis/reports.

Figure 3.3: Current hydrogen clusters, 2021

Source: Map based on Hydrogen valleys project by Fuel Cells and Hydrogen Join Undertaking and Mission Innovation.

Cross-border projects can also be marked as Important Projects of Common European Interest (IPCEI). These projects play an important role in the uptake of low-carbon hydrogen and the development of a European hydrogen infrastructure. In the summer of 2022, the European Commission approved up to EUR 5.4 billion of public support by fifteen Member States for IPCEI projects in the hydrogen value chain (IPCEI Hy2Tech). Hy2Tech was followed by IPCEI Hy2Use, a project worth up to EUR 5.2 billion of funding from Member States, which was approved by the Commission in September 2022[124]. In addition, there are other industry-based IPCEIs in Europe, and more likely to come, especially under the recently approved programs. Box 3.2 describes two examples of existing IPCEIs. Box 3.2 describes two examples of existing IPCEIs. In addition to these examples, there are three other industry-based IPCEIs in Europe, and more likely to come, especially under the recently approved Hy2Tech program.

[124] A joint program, Hy2Tech, EUR 5.4 billion in public funding and EUR 8.8 billion in private funding, was prepared and notified by 15 Members States. It consists of 41 projects, and includes 35 companies. European Commission (2022), available at: https://ec.europa.eu/commission/presscorner/detail/en/ip_22_4544. Hy2Use has been allocated EUR 5.2 billion from 13 Member States, and was approved by the Commission in September 2022. European Commission (2022), available at: https://ec.europa.eu/commission/presscorner/detail/en/ip_22_5676.

Box 3.4: Examples of current hydrogen projects[125] [126]

Green Octopus is an IPCEI with the objective to create a hydrogen backbone between Belgium, the Netherlands and Germany, and with further connections to France and Denmark. It mainly serves chemical industries, refineries and steel industries in these Member States. Green Octopus started in 2019 and is expected to be finalized by 2030.

Black Horse is another IPCEI that includes Slovakia, Czech Republic, Poland and Hungary, and focused on decarbonisation of the transport sector in the region. Hydrogen production and investment volume of the project are 320 tonnes/day and EUR 5,800 million, respectively.

Source: Hydrogen valleys project by Fuel Cells and Hydrogen Join Undertaking and Mission Innovation.

TSOs or DSOs are not significantly involved in the existing hydrogen infrastructures, since the hydrogen pipeline networks are mostly connecting local or regional industrial sites. In France, Germany, Belgium and the Netherlands, not one network is operated by TSOs or DSOs[127] and all are privately-owned. These industrial clusters likely form most of the future renewable hydrogen demand. It is estimated that the decarbonisation of their sole hydrogen demand will require approximately 300 TWh of low-carbon hydrogen in 2050[128]. However, some studies estimate higher demands. Production of low-carbon hydrogen needs to be ramped up to facilitate this surge in demand. Production and consumption of low-carbon hydrogen will likely not always take place at the same location, thus transportation of vast volumes of hydrogen needs to be facilitated. Furthermore, local networks transporting hydrogen to these industrial sites are crucial in connecting the future supply and demand of hydrogen.

3.2. Scenarios for the uptake of hydrogen in the EU

There are differences between scenarios estimating the future hydrogen supply and demand with some being more optimistic about the use cases of hydrogen while others see the demand to be more restricted.

The **European Hydrogen Backbone (EHB) initiative**, managed by a group of European energy infrastructure operators, assumes a more optimistic scenario while the **model of "no-regret hydrogen"**, presented by AFRY and Agora Energiewende, takes a more restricted perspective. One clear expectation regarding overall gas demand is that it will likely decrease by 2050 and beyond[129] due to decarbonisation policies. The same will likely apply also to low-carbon gases. However, the hard-to-abate sectors will probably need to ensure a certain level of demand for gaseous energy carriers even after 2050.

[125] Fuel Cells and Hydrogen Join Undertaking and Mission Innovation, Hydrogen valleys: Green Octopus, available at: https://h2v.eu/hydrogen-valleys/green-octopus.

[126] Fuel Cells and Hydrogen Join Undertaking and Mission Innovation, Hydrogen valleys: Black Horse, available at: https://h2v.eu/hydrogen-valleys/black-horse.

[127] ACER ran a survey to NRAs, responses from 23 NRAs. The report, 2020, is available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20NRAs%20Survey.%20Hydrogen%2C%20Biomethane%2C%20and%20Related%20Network%20Adaptations.docx.pdf.

[128] This is based on calculations for industrial no-regret hydrogen demand in report by AFRY and Agora Energiewende. AFRY, Agora Energiewende, 2021, *No-regret hydrogen: Charting early steps for H2 infrastructure in Europe*. Available at: https://www.agora-energiewende.de/en/publications/no-regret-hydrogen/.

[129] According to the IEA (2022 Q3 report), EU's gas consumption is set to decline by 10% by the end of 2022, Germany alone will reduce gas consumption by 20%.

In terms of future hydrogen demand and supply, the EHB initiative[130] presents a vision of how the EU hydrogen target could be achieved. According to the first EHB report, one hydrogen pipeline can transport approximately 65 TWh of hydrogen per year. **This indicates that about five large-scale pipeline corridors are required to meet half of the EU target of 10 million tonnes** (i.e. 330 TWh). The updated vision indicates that there is a potential for up to five corridors, with a total length of 28,000 km, to emerge by 2030. The infrastructure vision is created based on supply potentials, demand and possibilities for repurposing gas networks and the ability to build new infrastructure. More than half of the EHB vision consists of repurposed pipelines. In the 2040 scenario, the EHB can reach almost 53,000 kilometres. However, EHB **recognises the dependence on future supply and demand**, and its development can affect the 2030 and 2050 visions. As the EHB initiative working group consists of infrastructure operators, it shows the willingness, in terms of infrastructure, of the European TSOs to commit to the latest EU targets on hydrogen.

Uncertainty about the future uptake of hydrogen remains high. It is debatable what sectors are likely to switch to hydrogen in their production processes or delivery of services. Successful hydrogen projects have been able to thrive due to, among others, the ability to find business cases that can link hydrogen production with demand, that is to say, consumer willingness to pay. The aforementioned **no-regret corridors for hydrogen**[131] are unlike the EBH based on the industry demand. These scenarios project the expected uptake of hydrogen in the hard-to-abate sectors. According to the report, these sectors account for a majority of hydrogen demand in the future as they only have limited alternative decarbonisation options. The report concludes that the major demand will likely be **located in North Rhine Westphalia in Germany, Flanders in Belgium and the Netherlands**. This is in line with the current clusters in the same area. In addition, other larger no-regret demand hubs will likely be located, for example, in Lithuania. The report also concludes that the **future hydrogen networks will be smaller than the existing natural gas network**, even in the most optimistic scenarios. It can be argued that these no-regret corridors take a more demand-driven rather than a policy-driven approach. This view has been echoed by some stakeholders during the interviews, who also argued for an approach focused more on connecting clusters of import and production with industrial users.

A **coordinated, cross-border EU hydrogen network brings particular benefits regarding the cost-effectiveness and scope of decarbonisation**. According to a study by European Commission[132], a coordinated hydrogen infrastructure, taking into account national supply and demand potentials, can significantly reduce the overall costs of hydrogen uptake. A broad network can also support a broad decarbonisation process that is not only focused on certain geographical areas. On the contrary, ACER concludes from a review of existing literature[133] that there is no evidence that a pan-European hydrogen network would be justified based on the demand, technology and cost assumptions.

[130] *European Hydrogen Backbone: A European hydrogen infrastructure vision covering 28 countries*, 2022, available at: https://gasforclimate2050.eu/wp-content/uploads/2022/04/EHB-A-European-hydrogen-infrastructure-vision-covering-28-countries.pdf

[131] AFRY, Agora Energiewende, 2021, *No-regret hydrogen: Charting early steps for H2 infrastructure in Europe*. Available at: https://www.agora-energiewende.de/en/publications/no-regret-hydrogen/.

[132] European Commission, 2021f, *METIS study on costs and benefits of a pan-European hydrogen infrastructure*. Available at: https://op.europa.eu/en/publication-detail/-/publication/c50a12fc-5eeb-11ec-9c6c-01aa75ed71a1/language-en.

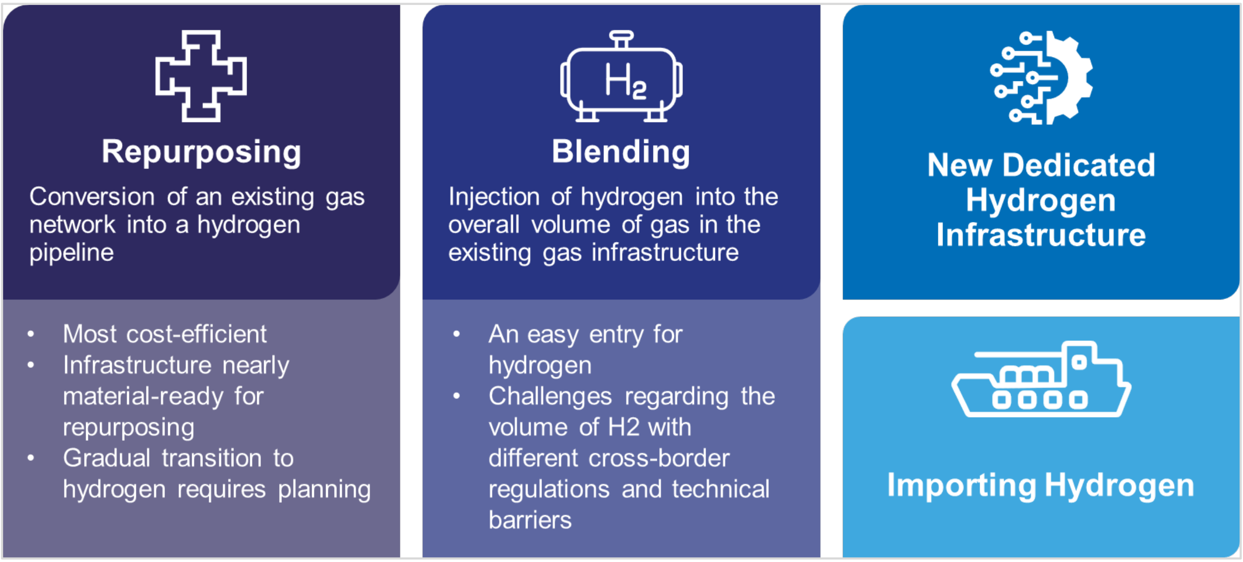
[133] ACER, 2021(b), Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing. Available at: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure_Overview%20of%20studies.pdf.

3.3. Uptake of hydrogen infrastructure

3.3.1. Options for the deployment of hydrogen infrastructure

In this section, we first discuss the barriers and opportunities of repurposing natural gas infrastructure to hydrogen infrastructure. Second, we describe the development of new infrastructure and blending options. Finally, this section provides a discussion on utilising existing LNG facilities to import hydrogen. Figure 3.2 presents the main options for the deployment of hydrogen, which will be analysed further in this section.

Figure 3.4: Options for the uptake of hydrogen



Source: Authors' own elaboration.

Repurposing natural gas infrastructure

Repurposing natural gas networks to hydrogen is generally accepted as the most cost-effective option[134]. Essentially, all the scenarios of future European backbones rely mostly on repurposed assets. As hydrogen is expected to partly replace the use of natural gas, it can be assumed that supply and demand will partly follow the current supply and demand for gas. The costs of repurposing have been estimated to be 10-15% of the costs of building a dedicated hydrogen infrastructure[135]. Investment costs for conversion of gas transmission networks are estimated to be EUR 0.37 million per km[136] and transport costs of onshore backbone EUR 0.11-0.21 per kg of hydrogen per 1,000 km transported.[137] Moreover, there will still likely be a need for gas-only networks, which indicates that not all the existing gas infrastructure can be converted to hydrogen.

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134 Among others, ACER overview of existing studies on repurposing, 2021, makes this conclusion. Available at: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure_Overview%20of%20studies.pdf.

135 Siemens Energy, Gascade Gastransport GmbH, Nowega GmbH, 2020. *Hydrogen infrastructure: The practical conversion of long-distance gas networks to hydrogen operation.*
Available at: https://www.gascade.de/fileadmin/downloads/wasserstoff/whitepaper-h2-infrastructure.pdf.

136 2019 prices. European Commission, 2020d. Hydrogen generation in Europe: Overview of costs and key benefits. p.14.

137 Estimated costs presented here are for EHB 2040 vision. Gas for Climate, 2022, *European Hydrogen Backbone: A European hydrogen infrastructure vision covering 28 countries*. Available at: https://gasforclimate2050.eu/wp-content/uploads/2022/04/EHB-A-European-hydrogen-infrastructure-vision-covering-28-countries.pdf.

However, as discussed previously, it is expected that the hydrogen backbone will not become as extensive as the current gas infrastructure[138]. In addition, the general view of gas network operators is that current gas network materials are nearly ready for conversion to hydrogen without the need for major changes in the current infrastructures. For example, 1.15 million km, or 96% of local networks are material-ready for repurposing to hydrogen infrastructure[139].

Blending hydrogen to natural gas networks

Blending represents an option **for the gradual introduction of hydrogen into existing gas networks**. Blending requires retrofitting the existing gas network to allow for the injection of hydrogen. Blending renewable hydrogen with natural gas can support the decarbonisation of the economy as the CO_2 intensity of the blended gas will be lower compared to using pure natural gas. More importantly, it can be a useful tool for a transitional phase as allows for creating hydrogen demand in regions that lack dedicated hydrogen networks or available infrastructure to be repurposed entirely.

The **debate around blending concerns the different blending levels and approved shares of hydrogen in pipelines**. Currently, there are different regulations regarding blending at a national level and no EU-wide standards. However, the European Commission's proposal on the revision of the Gas Regulation states that TSOs shall accept up to 5% hydrogen blends at interconnector points between the Member States from 1 October 2025, which would ensure cross-border flows.

Currently, blending is not widely accepted in the Member States, as 65% of TSOs[140] do not accept the injection or allow hydrogen volumes into the gas network, and even when hydrogen is accepted, it concerns only very low concentration levels. Moreover, it was mentioned during stakeholder interviews for this study that **some industrial players oppose blending, as this would affect the purity of the gas and hence production processes need to be adjusted**. Therefore, the European Commission and many stakeholders see only a limited and short-term role in blending hydrogen in areas where pure hydrogen cannot be absorbed.

Moreover, the readiness of the gas transmission network to accept hydrogen is still at an early stage. Currently, several TSOs are assessing the technical requirements for allowing blending in existing gas infrastructure. Yet, it is estimated that in some Member States low blending percentages, 2-10% in volumetric terms, are technically feasible with only a few adaptations[141]. **Blending does, however, seem to be a suboptimal tool to enhance decarbonisation as it poses additional costs and results in lower savings of CO_2 emissions** compared to using hydrogen directly. Furthermore, it does not specifically target the end-users that would need hydrogen to decarbonise[142]. It is, therefore, **a tool to support market demand and thereby increase the uptake of hydrogen**.

[138] AFRY and Agora Energiewende, 2021, *No-regret hydrogen: Charting early steps for H2 infrastructure in Europe*, available at: https://www.agora-energiewende.de/en/publications/no-regret-hydrogen/.

[139] Ready4H2, a project consisting of 91 European gas distribution companies and organisations, estimates the number in their report, 2021, available at: https://www.ready4h2.com/_files/ugd/597932_0d67d1d9fd3e467ea03d941fcbb6a645.pdf.

[140] ACER ran a survey to NRAs, responses from 23 NRAs. The report, 2020, is available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20NRAs%20Survey.%20Hydrogen%2C%20Biomethane%2C%20and%20Related%20Network%20Adaptations.docx.pdf.

[141] GRTgaz et al., 2019. *Technical and economic conditions for injecting hydrogen into natural gas networks*. Available at: https://www.elengy.com/images/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf.

[142] Fraunhofer IEE, 2022, *The limitations of hydrogen blending in the European gas grid.*

Construction of new hydrogen infrastructure

The third option for the deployment of hydrogen is the construction of new infrastructure dedicated only to hydrogen. As discussed above, the construction of new hydrogen pipelines results in higher costs than the repurposing of existing natural gas networks. Investment costs for the construction of new hydrogen transmission networks are estimated to be EUR 0.93-3.28 million per km[143]. It is, therefore, not cost-effective to construct a hydrogen network next to the existing natural gas network.

Nevertheless, the **construction of new hydrogen infrastructure is necessary for the development of a European hydrogen network**. As the use of natural gas networks is expected to gradually decrease, the timing of repurposing combined with the construction of new infrastructure (through network planning) is crucial. Construction of new infrastructure might, furthermore, be required if there is a need to keep the gas infrastructure running in parallel. Therefore, the option is usually seen as a solution complementing the repurposing of existing infrastructure and could be key to ensuring there are infrastructure pipelines connecting initial hydrogen clusters.

Repurposing LNG terminals for importing hydrogen

Out of the 20 million tonnes of renewable hydrogen targeted in the REPowerEU plan, half should be satisfied through imported hydrogen. At COP27 in November 2022, the European Commission communicated about the establishment of several partnerships, with Egypt, Kazakhstan and Namibia, on renewable hydrogen. Through these so-called Green Hydrogen Partnerships, the Commission will promote hydrogen imports from third countries and incentivise decarbonisation[144].

Since the invasion of Ukraine, the pressure has been on reducing the dependency on Russian natural gas and restructuring the energy import system. However, the main short-term objective is not to transit to renewable gas, but to ensure the security of the supply of gas. This has led countries like Germany to speed up the construction of new terminals to import natural gas. An option to support future hydrogen uptake that has been proposed is repurposing these LNG terminals to import hydrogen. The German terminals are planned with the future use of clean fuels, including hydrogen, in mind. Yet the possibility and effectiveness of repurposing LNG terminals are rather uncertain, since none of the equipment is suitable to handle hydrogen, as hydrogen molecules are smaller than molecules in natural gas. **Therefore, the conversion of an LNG terminal would be a technical challenge, as the methods for it are still very theoretical**[145].

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[143] 2019 prices. European Commission, 2020d. *Hydrogen generation in Europe: Overview of costs and key benefits*. p. 14-15.

[144] European Commission, 15 November 2022, *In focus: Renewable hydrogen to decarbonise the EU's energy system*. Available at: https://ec.europa.eu/info/news/renewable-hydrogen-decarbonise-eus-energy-system-2022-nov-15_en.

[145] Shiryaevskaya, A. 2022. *How Germany's LNG Terminals Will Morph Into Green Hydrogen Hubs*. In Bloomberg. Available at: https://www.bloomberg.com/news/articles/2022-05-12/how-to-turn-lng-terminals-into-green-hydrogen-hubs?leadSource=uverify%20wall.

This raises the risk of **LNG terminals becoming stranded assets** and creates a challenge in the transition to hydrogen. Nevertheless, several companies seem confident that the risk is not significant. New terminals are already being built and they have committed themselves to the hydrogen and green energy carriers business. In particular, there are plans of importing green ammonia and carbon-neutral synthetic LNG[146] and other green gases that can be used to produce large amounts of renewable hydrogen[147]. In addition, regarding the risk of stranded assets, it is noteworthy that LNG terminals can have also the role of backup assets and ensure the security of supply, even if they were not used most efficiently.

3.3.2. Key needs to facilitate the deployment of hydrogen infrastructure

Development of infrastructure is known as being resource-intensive and large-scale projects can take several years. The estimated required time for large-scale transmission, storage and port infrastructure implementation can be up to 10 years[148]. Both the presented scenarios as well as experiences from existing hydrogen projects indicate that certain circumstances will enable, speed up and facilitate the uptake of hydrogen infrastructure. Key characteristics that enable the smooth development of a European hydrogen infrastructure include:

- **Coordinated planning and collaboration** between key stakeholders are needed particularly for the creation of a pan-European network. This does not only include cooperation between the Member States but also establishing international partnerships with countries outside of the EU. In addition, more integrated system planning between hydrogen, gas and electricity infrastructure can support the establishment and effectiveness of the uptake of hydrogen; and
- **Regulation** to facilitate the repurposing of existing gas networks is crucial, as well as the simplification of the planning and permitting procedures. For example, local network operators and DSOs demand more permissions and mandates to act at a more local level[149].

Linked to the needed regulation, **political support** and support from the local public are essential to implement large-scale infrastructure projects. This regards financing and providing stability, but also in terms of cooperation between authorities and operators.

Public financial support, for example, financing provided by the EU funds can define the successful deployment of hydrogen. Financing opportunities are described further in the following section.

Finally, another aspect to be addressed when planning the hydrogen infrastructure is the **potential risk of hydrogen leakage**. Due to the very small size of hydrogen molecules, they can easily pass through materials. Hence, the hydrogen economy causes a risk of hydrogen leakage, which has an indirect negative effect on climate by extending the lifetime of GHG in the atmosphere.

As hydrogen production, transportation and use are expected to increase significantly in the near future, and therefore the risks can increase as well, it is important to recognize the potential negative

[146] Green ammonia: green hydrogen combined with nitrogen, can be used to make fertilizer or burned for power. Synthetic LNG: green hydrogen combined with dioxide, can be used the same way as conventional natural gas. Ibid.

[147] For example, TES plans to import enough green gas to produce more than 5 million tonnes of hydrogen, Uniper SE plans to build a terminal that will be a part of green hydrogen hub, Brunsbüttel plans to import carbon-neutral synthetic LNG and green ammonia. Ibid.

[148] Gas for Climate, 2022, *European Hydrogen Backbone: A European hydrogen infrastructure vision covering 28 countries*. Available at: https://gasforclimate2050.eu/wp-content/uploads/2022/04/EHB-A-European-hydrogen-infrastructure-vision-covering-28-countries.pdf.

[149] Ready4H2, a project consisting of 91 European gas distribution companies and organisations, stated the need for local mandates in its report, 2021, available at: https://www.ready4h2.com/_files/ugd/597932_0d67d1d9fd3e467ea03d941fcbb6a645.pdf; the European Commission's study on the role of Gas DSOs in the energy transition, 2022, indicated a similar need, available at: https://op.europa.eu/en/publication-detail/-/publication/cad1a27a-7fbb-11eb-9ac9-01aa75ed71a1/language-en.

effects and ensure that technology is secure enough to prevent leakage. It has been estimated that the transportation of hydrogen is linked to a relatively low risk of leakage, approximately 2 per cent for the whole life-cycle of transportation and storage of hydrogen. Nevertheless, it places additional requirements for regulation, planning and implementation of repurposing of gas networks and LNG terminals[150].

3.3.3. Financing opportunities for hydrogen infrastructure

The uptake of hydrogen will take time and not all capacity will be used from the start. Revenues from user tariffs will be insufficient in the first years. Hence, there must be sufficient financing opportunities to support the investment need for hydrogen infrastructure. Financing opportunities for energy infrastructure include a business case for infrastructure and revenues generated through congestion rents or targeted subsides, loans, and grants.

One financing opportunity for hydrogen infrastructure is **the revenue from gas operators or producers, which could be used to develop hydrogen infrastructure**. Financial transfers between regulated separate assets so-called cost mutualisation or cross-subsidies[151] [152] have been presented as one of the potential ways to finance the development of hydrogen infrastructure. The suggestion, as endorsed by European TSOs through ENTSOG, means that the hydrogen network costs would be partly or fully mutualised with gas network costs, even though the assets are separated according to unbundling rules.

In the case of cost mutualisation, costs are spread across gas and hydrogen users, meaning that gas consumers would carry an additional financial burden during the hydrogen development phase. It has been pointed out by regulators that the end users of hydrogen will likely differ from the ones of natural gas, which **could lead to households financing the decarbonisation of industry** putting additional pressure on households when gas prices are already high. The Commission proposal, therefore, allows for financial transfers only up to a certain limit and not lasting longer than one-third of the depreciation period of the infrastructure concerned[153]. Criticism towards financial transfers between different sectors sees it as a burdensome and gas market-distorting tool.

However, when looking at the gas infrastructure, **the development of new and large-scale and in particular cross-border infrastructure was possible only through national and EU-level funding**.

For example, the study supporting the impact assessment for the revision of the TEN-E Regulation found that the total amount of funding realised for gas PCIs summed up to EUR 1.5 billion between 2014 and 2020, which is about 40% of the total CEF funding for energy projects[154].

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[150] For more information on the risk of leakage, technologies to prevent it, and recommendations, see: Fan et al., 2022, Hydrogen leakage: A potential risk for the hydrogen economy, Center on Global Energy Policy at Columbia University SIPA. Available at: https://www.energypolicy.columbia.edu/research/commentary/hydrogen-leakage-potential-risk-hydrogen-economy#:~:text=In%20the%20future%2C%20leaked%20hydrogen,not%20exist%20at%20scale%20today.

[151] European Commission, 2021, Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen, Article 4.

[152] ENTSOG listed cost mutualisation as an option for financing in its position paper of Initial Proposals for Addressing Hydrogen Regulation in the Revision of the 3rd Energy Gas Package (2021), available at: https://www.entsog.eu/sites/default/files/2021-03/ENTSOG%20-%20Gas%20networks%20-%20revision%20of%20EU%20rules%20on%20market%20access_Long.pdf.

[153] See also Article 4 on the separation of regulated asset bases, which discusses financial transfers between regulated services that can be collected as a dedicated charge, Proposal for a Regulation on the internal markets for renewable and natural gases and for hydrogen (recast), COM(2021) 804 final.

[154] European Commission, 2021a, Directorate-General for Energy, Akkermans, F., Le Den, X., Heidecke, L., et al., Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure, Publications Office, 2021. Available at: Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure.

Central for investments in energy and gas infrastructure projects is the **TEN-E Regulation**, which provides funding through the **Connecting Europe Facility (CEF)**.

As previously explained the revised TEN-E Regulation added hydrogen transport infrastructure and certain types of electrolysers under its gas category. CEF provides funding through grants for electricity transmission, natural gas transmission and smart grids. For the 2021-2027 period, EUR 5.84 billion has been allocated to energy projects under CEF for Energy. Specifically, CEF for Energy supports sustainable energy infrastructure projects and recently launched a call for Cross-Border Renewable Energy (CB RES) projects. Among the first three CB RES projects is a renewable electricity production project in Germany, Italy and Spain with the purpose to convert, transport and use clean hydrogen in the Netherlands and Europe.

To qualify for CEF funding, projects have to be categorised as **Projects of Common Interest (PCIs)**[155]. These are key cross-border infrastructure projects linking the energy systems of European countries. To get PCI status, the project must have a significant impact on energy markets and market integration in at least two Member States, boost competition, help the EU's energy security by diversification, as well as support the achievement of the climate and energy goals.

Regarding financing, the TEN-E Regulation follows a three-step logic[156]:

1. In principle, infrastructure should be paid for through congestion rents (i.e. the revenue generated by a TSO). If the congestion rents cover project costs, a project can be considered sufficiently commercially viable and no further provisions are applicable;
2. If a TSO is not able to recover the costs of the network through congestion rents, then the TEN-E Regulation establishes that it should be paid for by network users through tariffs for network access. The provision on cross-border cost allocation (CBCA) allows for a (re)allocation of project costs to the Member States, where the project has a net positive impact; and
3. Finally, if the reallocation of costs through CBCA is still not sufficient and a project remains commercially non-viable, PCIs can, under certain conditions, apply for EU financial assistance in the form of grants.

Of similar importance to CEF funding are the **Important Projects of Common European Interest (IPCEIs)**[157]. These are innovation and infrastructure projects, targeting to significantly support the achievement of EU strategies. An IPCEI has to "overcome market failures and enable breakthrough innovation in key sectors and technologies and infrastructure investments, with positive spill-over effects for the EU economy at large".

In contrast to CEF, these are led by the Member States and funded by national budgets, but the status of IPCEI leads to an opportunity to exceed the limits of state aid regulated by the Commission. Consequently, this means that public support has to be notified to the Commission for approval. The revised IPCEI communication, in effect from 1 January 2022, sets the criteria for the Commission to

155 European Commission communication of PCIs, available at: https://energy.ec.europa.eu/topics/infrastructure/projects-common-interest/key-cross-border-infrastructure-projects_en.

156 European Commission, 2021a, Directorate-General for Energy, Akkermans, F., Le Den, X., Heidecke, L., et al., Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure, Publications Office, 2021. Available at: Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure.

157 European Commission communication on IPCEIs, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.C_.2021.528.01.0010.01.ENG&toc=OJ%3AC%3A2021%3A528%3ATOC.

assess national support for IPCEIs. So far, several hydrogen projects have obtained IPCEI status such as Hy2Tech and Hy2Use (see also section 3.1).

Beyond CEF funding and IPCEIs, there are several EU funding opportunities and financial instruments that offer grants and loans in the context of energy, as well as instruments and mechanisms to facilitate funding and leverage private sector financing:

- **Modernisation Fund**[158]: Supporting ten lower-income EU Member States (Bulgaria, Croatia, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Romania and Slovakia) through grants, guarantees, loans and capital injections for investments in energy networks and energy security among other. The fund derives its revenues from the auctioning of 2% of the total ETS allowances for 2021-30 and its total revenues may amount to EUR 48 billion from 2021 to 2030 (at EUR 75 / tCO2);
- **European Fund for Energy, Climate Change and Infrastructure - Marguerite Fund**[159]: Equity fund with participation of European Investment Bank and other international financial institutions for greenfield and brownfield infrastructure investments amounting to EUR 700 million in 2018 – 2028;
- **InvestEU**: Under the Climate and Infrastructure Funds[160] offered by the European Investment Fund (EIF), the EIF provides equity investments for renewable energy generation, transmission, distribution and storage as well as for cross-border energy infrastructure and PCIs;
- **Recovery and Resilience Facility (RRF)**: Funding for green and sustainable energy sector projects and interventions through grants and loans. A minimum of 37% of the EUR 672.5 billion needs to be allocated to green investments and reforms. According to a dataset collected by Bruegel, the 26 submitted National Recovery and Resilience Plans (NRRPs) contain EUR 52.73 billion dedicated to the energy sector[161]; and
- **Innovation Fund and the newly proposed European Hydrogen Bank**: In the State of the Union speech, the Commission announced a new European Hydrogen Bank[162], worth EUR 3 billion. It will support the achievement of the EU hydrogen targets and aim to close investment gaps and connect supply and demand by guaranteeing the purchases of hydrogen to create certainty of demand.

  However, the European Commission has not released any details yet on how this bank would function[163] apart from it being funded by the Innovation Fund, which itself consists of the revenues of the EU Emissions Trading System (ETS). More than EUR 38 billion of ETS revenues

[158] European Commission, n.d., Funding for climate action, Modernisation Fund. Available at: https://ec.europa.eu/clima/eu-action/funding-climate-action/modernisation-fund_en.

[159] For more information, see: https://www.marguerite.com/portfolio/.

[160] For more information, see: https://engage.eif.org/investeu/climate-infrastructure-funds.

[161] EUR 52.73 billion is dedicated to the economic sector of Electricity, gas, steam and air conditioning supply (NACE code D), available at: https://www.bruegel.org/dataset/european-union-countries-recovery-and-resilience-plans.

[162] The State of the Union 2022 by Ursula von der Leyen, 14 September 2022, available at: https://ec.europa.eu/commission/presscorner/detail/en/speech_22_5493.

[163] There has been some speculation the new Hydrogen Bank would use its capital to buy up all ten million tonnes of the EU's 2030 green hydrogen annual production target and then resell it to market at a lower price under a Carbon Contracts for Difference scheme, see: https://www.rechargenews.com/energy-transition/from-niche-to-scale-eu-launches-3bn-european-hydrogen-bank-with-a-bang-but-keeps-quiet-about-the-details/2-1-1299131.

were allocated to the Fund for 2020-2030, and EUR 1.8 billion in clean tech projects, including hydrogen[164].

Finally, the **European Investment Bank (EIB)** provides also funding opportunities. As noted in Chapter 1, the EIB no longer supports natural gas energy projects and any other project concerning traditional fossil fuels. Instead, for energy infrastructure, it focuses on supporting the development of infrastructure to transport low-carbon gases such as hydrogen (next to electricity infrastructure)[165]. **In 2020, the EIB provided EUR 455 million in investment for gas[166].** For hydrogen, the EIB signed an advisory agreement with Hydrogen Europe to support the identification of projects that could receive EIB financing.[167] Furthermore, the European Clean Hydrogen Alliance launched a call for electrolyser manufacturing and electrolyser deployment projects to submit applications for EIB Advisory support[168].

164 European Commission communication of the Innovation Fund, available at: https://ec.europa.eu/commission/presscorner/detail/en/ip_22_4402.

165 EIB, 2019, *EIB Energy Lending Policy. Supporting the energy transformation.* Available at: https://www.eib.org/attachments/strategies/eib_energy_lending_policy_en.pdf.

166 EIB, 2021(a), *Energy Overview*. Available at: https://www.eib.org/attachments/thematic/energy_overview_2021_en.pdf.

167 EIB, 2021(b), 29 July, *EIB signs advisory agreement with Hydrogen Europe*. Available at: https://www.eib.org/en/press/all/2021-284-eib-signs-advisory-agreement-with-hydrogen-europe.

168 EIB, 2022, 16 March, *EIB looking to invest in Hydrogen projects*. Available at: https://www.eib.org/en/press/news/eib-looking-to-invest-in-hydrogen-projects.

4. ENSURING ENERGY SUPPLY THROUGH GAS INFRASTRUCTURE

KEY FINDINGS

Following Russia's invasion of Ukraine and a substantial reduction of pipeline gas flows by Gazprom, a fast and efficient restructuring of the EU's gas import portfolio is necessary. That would require a reorganisation of the EU's gas system to accommodate structural shifts in gas flows, which have been already occurring across the EU. Over the last decade, substantial progress has been made in **increasing gas interconnectivity**, particularly in Central and South-East Europe and the Baltics. That increased robustness of the gas system in case of physical interruptions, from Russia in particular. Still, **several bottlenecks remain across the EU**. Several gas PCI projects still experience delays and rescheduling due to various factors, mainly financing and permitting. Other bottlenecks emerge as a result of the ongoing substitution of Russian pipeline imports. The key one is located in **North-West Europe**, between Belgium, France and Germany. With certain regulatory and infrastructural adjustments, supplies can be increased from French, Belgian and Dutch LNG terminals into Germany. The **Iberian Peninsula** is another bottleneck as its rich LNG capacity cannot be used to source other Member States due to infrastructural constraints.

LNG is becoming a key supply source to re-adjust the EU import structure due to a phase-out of Russian pipeline gas imports. For the first time, in 2022, LNG imports surpassed pipeline gas imports. Although LNG technical capacity is sufficient to satisfy almost 60% of the current EU gas demand, for years, LNG imports did not trespass one-fifth of the EU gas portfolio and the average **utilisation rate** of LNG terminals remained low. The volatility of LNG imports into the EU is closely linked to the global supply side, such as global competition for spot cargoes. However, other factors affect terminals' utilisation as well. The terminals, at which **long-term capacity contracts tend to prevail**, had higher capacity utilisation. Some of these terminals are also exempted from regulated access. **Regulatory settings of terminals**, including services offered, also affect the procurement of LNG.

To mitigate the current supply bottlenecks, in 2022, several Member States streamlined the **expansion of LNG terminals and leasing of new FSRUs**, often in record time. Although **permitting** has remained a sensitive issue in many Member States, some of them, i.e. the Netherlands and Germany, exemplified streamlining of approval procedures. At the same time, emerging competition among Member States around new terminals may lead to suboptimal outcomes in terms of creating gas overcapacity.

Gas storage is a key component of the gas system providing security of supply and system flexibility covering peak demand during the winter season. Recently, the business case of gas storage was challenged by ever-narrowing summer-winter spreads. Low levels of storage filling in 2021 and Russia's invasion of Ukraine in 2022 facilitated a fast adoption of the Gas Storage Regulation that provided **a minimum of 80% gas storage level obligation** by 1 November for winter 2022, rising to 90% for the following years, and **obligatory certification of Storage System Operators**.

4.1. The current state of the gas infrastructure system throughout Europe

High energy prices, reduced natural gas flows from Russia, and tight global LNG supply have created a "perfect storm" on the European gas markets in 2022. Following Russia's invasion of Ukraine in late February 2022 and a domino effect of disruptions of Gazprom's gas supply that have occurred since April 2022, a fast and efficient replacement of total gas imports from Russia has become a priority for the EU. The REPowerEU Plan published by the European Commission in May 2022 provided a list of concrete measures that could allow a two-thirds reduction of supplies from Russia by the end of 2022[169]. Among the proposed measures, which include energy saving and faster uptake of renewables and clean alternatives to natural gas, the Plan outlines actions to diversify energy, particularly, gas imports. That would need to source about 50 bcm of LNG and 10 bcm of pipeline gas alternative to Russian supplies by the end of 2022[170].

With a substantial share in the EU import portfolio, the replacement of Russian pipeline gas will affect the entire gas infrastructure system in the EU. Targeted investment would be needed to mitigate remaining physical and regulatory infrastructural bottlenecks. The REPowerEU Plan provides an initial assessment of the current infrastructural bottlenecks and required investment in gas infrastructure (see section 4.2).

With energy security challenges related to Russia having been amplified since 2022, the policy debate about the security of supply in the EU is being shifted from **the risk aversion of dependence on one dominant supplier** to a need to completely transform the markets to **replace the entire volume of imports from the single jurisdiction, i.e. Russia**. For that purpose, there is a need to assess the current state of the gas infrastructure and options available to ensure gas supply both immediately during winter 2022/23 and in the mid-term by 2030.

4.1.1. Changing patterns of gas flow across the EU

According to the ACER/CEER Annual Report published in July 2022, a 'significant **structural shift in flow patterns**' has been occurring in European gas markets since 2022[171]. A substantial reduction in flows from Russia to Germany and several other Member States was increasingly compensated by the accumulative loading of LNG terminals in the UK, Spain, and Belgium. As Figure 4.1 shows, the year-on-year change has been predominately notable in terms of supplies from Russia ('East' in Figure 4.1[172]) and LNG imports. Although import volumes have been fluctuating, a comparison of import dynamics from 1 October 2021 to 1 October 2022 shows a substantial shift. Supplies from 'East' steadily dropped from 3553 GWh/d to 733 GWh/d, while LNG imports grew from 1866 GWh/d to 3097 GWh/d respectively.

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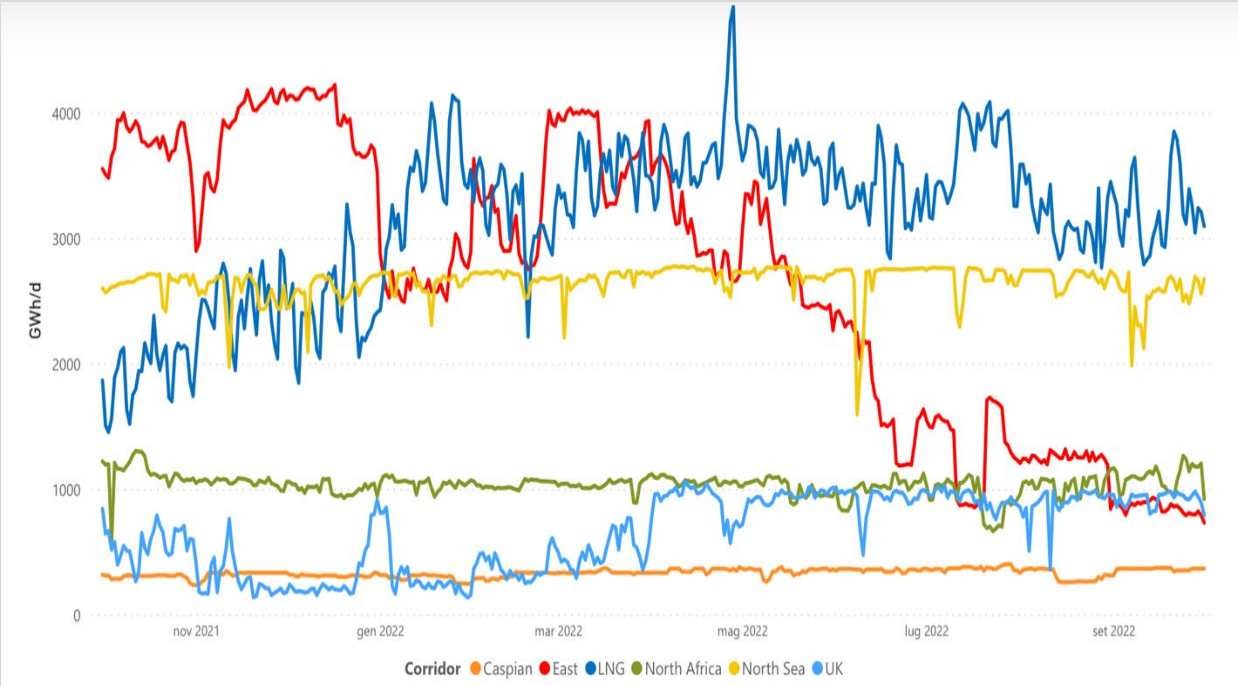
[169] European Commission, 2022b, *REPowerEU Plan*, COM (2022) 230 final.

[170] In addition to other measures, inter alia gas demand reduction, energy saving, increase of biomethane production and reduction of gas demand in the power sector, the REPowerEU estimates a reduction of Russia gas imports by 2/3 by the end of 2022. This estimates about 100 bcm or 1100 TWh. In the mid-term, supply diversification coupled with other measures, including fuel diversification by biomethane (17 bcm), renewable hydrogen, energy savings (59bcm), renewable electricity (21 bcm), REPowerEU Plan estimates a 30% reduction of EU gas demand (116 bcm or 1200 TWh) by 2030. See Annex 1, European Commission, 2022b, *REPowerEU Plan*, COM (2022) 230 final. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483.

[171] See p.34: ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*. July 2022.

[172] Includes also gas originated in Ukraine; gas of European shippers stored in underground facilities in Ukraine and transported back to EU Member States.

Figure 4.5: Gas flows in the EU according to corridors, 1 Oct. 2021 – 1 Oct. 2022, GWh/d



Source: ENTSOG Gasflow Dashboard, https://gasdashboard.entsog.eu.

These substantial reductions in imports from Russia result from a set of events[173]. Gazprom stopped flows via the Yamal-Europe pipeline towards Germany and Poland in May 2022, substantially reduced and later, indefinitely shutdown flows via Nord Stream1 in September 2022 due to alleged technical considerations[174]. Later, in September 2022, four leaks in both the Nord Stream 1 and 2 pipelines were discovered and made Nord Stream 1 non-operational. Supplies via the Ukrainian transit route have been reduced as well; gas has been no longer delivered via the Sokhranivka entry point of the Ukrainian gas transmission system since May 2022 after the Gas Transmission System Operator of Ukraine declared force majeure on the transit of gas entering that point[175]. On top of that, throughout the Spring and Summer of 2022, Gazprom's supplies were stopped or substantially reduced to several European customers in Austria, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Italy, Poland, the Netherlands, and Slovakia. These unilateral cuts resulted from the refusal of Gazprom's customers to shift to the rouble payment system for gas imports, which was unilaterally introduced by the Russian Government in April 2022[176].

[173] For a detailed assessment on July 2022 see McWilliams, Zachman, G, 2022, *European Union demand reduction needs to cope with Russian gas cuts*, Blog Post, Bruegel, 7 July. Available at: https://www.bruegel.org/2022/07/european-union-demand-reduction-needs-to-cope-with-russian-gas-cuts.

[174] See Sharples, J., 2022, *Falling like dominos: the impact of Nord Stream 1 on Russian gas flows in Europe*. August. Oxford Institute for energy Studies. Available at: https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2022/08/Insight-120-The-Impact-of-Nord-Stream-on-Russian-Gas-flows-in-Europe.pdf.

[175] S&P Global, 2022, *Ukraine's gas grid operator to suspend Russian gas flows via Sokhranivka*. 10 May. Available at: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/051022-ukraines-gas-grid-operator-to-suspend-russian-gas-flows-via-sokhranivka.

[176] For a detailed overview, see: Ason, A., 2022, *Rouble gas payment mechanism: implications for gas supply contracts*. Oxford Institute for Energy Studies, April 2022. Available at: https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2022/04/Rouble-gas-payment-mechanism.pdf.

Estonia, Latvia and Lithuania also ceased imports from Russia in April 2022. At the same time, Gazprom's export via TurkStream remained stable delivering gas to Turkey, Hungary and the Western Balkans.

On the contrary, substituting decreasing Russian pipeline gas, LNG imports grew significantly since 2022 accounting for a 60% YoY increase in Q1-2 2022. Particularly, a rise in LNG imports predominantly from USA and Qatar, but also Russia, was recorded at LNG terminals in Belgium, France, Italy, Lithuania, the Netherlands, and Poland, while relatively steady volumes were observed in Spain, Portugal, Croatia, and Greece[177].

The re-adjustments of import flows have revealed several **infrastructural constraints** and network bottlenecks, which are discussed in section 4.2. These constraints predominately derive from the legacies of the European gas system, which had been built to deliver gas from the Soviet Union and later Russia westwards. Rerouting gas flows to use the LNG import capacity of North-West Europe would require a reassessment of available capacity and identification of targeted investment into missing infrastructure[178].

The capacity market has also faced structural changes since 2022: the use of short-term booking capacity products has increased as a reaction to ongoing rerouting flows from North-West Europe eastwards.[179] That raises a need to adjust gas transportation mechanisms when higher spreads emerge between European gas hubs, and bottlenecks occur, as well as mitigate remaining contractual congestions across the EU[180].

4.1.2. Gas interconnectors

Substantial progress in ensuring gas interconnectivity has been made over the last decade[181]. Following the 2009 Russia-Ukraine gas transit dispute and the consequent interruptions of supplies to several EU Member States during winter 2009/10, several measures to enhance infrastructural interconnectivity had been taken under Regulation (EU) 994/2010 concerning measures to safeguard the security of gas supply[182]. In 2017, Regulation 994/2010 was repealed by a new Regulation 2017/1938[183]. First and foremost, the measures introduced concerned reducing the excessive dependence of Central and South-East Europe on Russian supplies and advancing an emerging gas market integration of these markets with adjacent North-West Europe[184].

Regulation (EU) No 994/2010 established the obligation to offer '**bi-directional capacity'** – i.e., permanent physical capacity to transport gas in both directions – at all EU cross-border

177 See 'LNG physical flows' at https://gasdashboard.entsog.eu.

178 ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*. July 2022.

179 See discussion in ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*. July 2022.

180 ACER, 2022(b), *9th ACER Report On Congestion In The EU Gas Markets And How It Is Managed. Period covered: 2021*. May 2022. Available at: https://www.acer.europa.eu/sites/default/files/documents/Publications/Congestion_9thEd_FINAL.pdf.

181 Progress has been reported in ENTSOG Security of Supply Simulations of 2017 and 2021, and noticed by most stakeholders interviewed.

182 Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC. Available at: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32010R0994 Available at: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32010R0994.

183 Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32017R1938 Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32017R1938.

184 For a detailed analysis, see: ACER and CEER, 2014, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2013. Gas Wholesale Markets Volume*, pp. 255-261. Available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf.

interconnections (unless exemption obtained) and to enhance alternative interconnection capacity. Both the construction of new cross-border interconnectors and (physical) reverse flow capabilities were delivered in line with the TEN-E Regulation and were typically funded by various EU programmes such as the PCIs. Several High-Level Groups [185] have been established across the macro-regions to facilitate market integration, identify cross-border needs and select gas (and electricity) infrastructure projects.

Bi-directional capacity can be either **physical or virtual** (also referred to as 'backhaul'). The physical reverse capacity allows re-directing supplies, in case of emergency or market signals at adjacent markets. In most cases, bi-directional capacity had been motivated by the security of supply concerns. Among the recent examples, the TAG Reverse Flow on the Trans Austria pipeline [186] was commissioned in 2020 but never used until 2022 when reverse flows started from Italy to Austria to compensate for reduced Gazprom's supplies to Austria.

Box 4.5: Key barriers to completing gas infrastructure projects

Although the improvements in gas market integration have been notable since 2010, the completion of some pipeline interconnectors faced various delays. ACER in its *2022 Annual monitoring report on the progress in implementing gas and electricity projects of common interest ('PCIs')* identifies that in 2021, 35% of the gas PCIs were rescheduled, and 20% encountered delays. According to ACER, this rescheduling could signal that initially the implementation schedules for these projects could have been too optimistic. Several key barriers, also flagged during the interviews with stakeholders and experts, are listed below.

Demand-side and **supply-side uncertainties** or **lack of market interest** were reported in most cases of PCIs rescheduling. Uncertainties surrounding the role of natural gas in the energy transition have contributed to lowered investors' confidence. As ACER and CEER (2022) notice in their Annual report, "policy and market developments sent opposing signals to investors in new gas infrastructure throughout the year[2021]". For future projects, the revised TEN-E Regulation has prioritised financing of low-carbon gas infrastructure and exclude most of gas infrastructure projects from future financing.

Lack of financial certainty of project promoters, insufficient institutional capacities and **political will** of Member States have been also listed by the stakeholders and experts interviewed as the main barriers that hindered the construction of new interconnectors in the past and delayed project implementation. Among others, the Interconnector Greece-Bulgaria is notable in that regard having experienced various delays over almost 10 years. However, in the current political context, some Member States, i.e. Germany and the Netherlands, have been smoothing the process ensuring urgent financial commitments and strong political backing for new gas infrastructure projects.

Permit granting is another key reason for delays. Slowed construction process due to slow regulatory approvals or difficulties encountered concerning local public administration has been also pointed out in the 2021 *ACER Consolidated report on the progress of electricity and gas Projects of Common Interest*, as well as raised by the stakeholders interviewed. In the past, regulatory complexity, also linked to the lack of clarity regarding the regulatory framework for new or incremental capacity, has led to several significant delays in project implementation.

Subdued regional cooperation among Member States is another barrier which contributed to the preservation of infrastructure bottlenecks and delays in project implementation. Some impediments were often added to the completion of interconnectors due to long deliberations on cross-border cost allocation.

Sources: The interviews with stakeholders and experts, and ACER, 2022, Consolidated report on the progress of electricity and gas Projects of Common Interest. June; and ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*. July 2022.

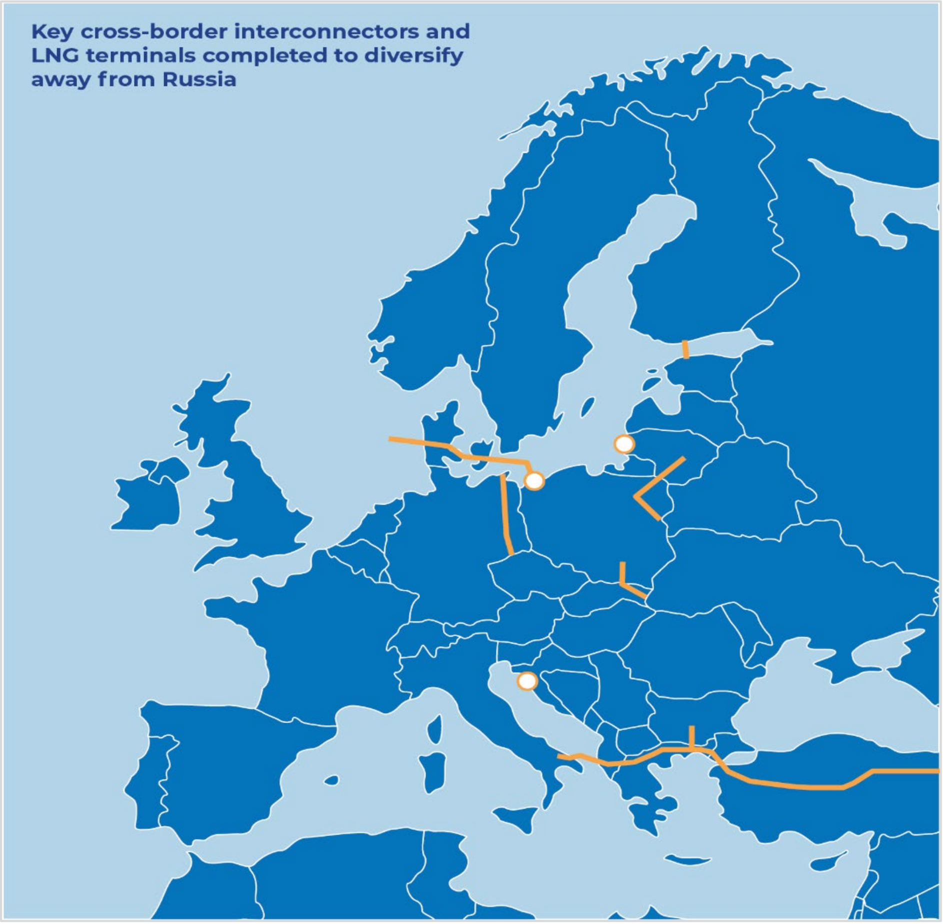
[185] Central and South-eastern Europe Energy Connectivity (CESEC), Baltic Energy Market interconnection Plan (BEMIP), Interconnections for South-West Europe, and the North Seas Energy Cooperation.

[186] The TAG delivers gas from the Slovakia-Austria border to Italy, Slovenia, and Croatia.

The value of new interconnection capacity is also to facilitate greater volumes of **gas trading** and to reduce price divergence between neighbouring markets. **Virtual reverse flow ('backhaul')** allows purchasing gas by netting gas volumes that have been contracted for transmission in an opposite direction. Some key interconnectors linked Germany and adjacent markets of Central Europe. For example, virtual interconnection points were delivered from Germany to Poland[187] and between Poland, Slovakia and Hungary and Ukraine since 2014. Although historically flows were moving from East to West in Central and Eastern Europe, expansion of capacities among others facilitated gradual cross-border trade in the West-East direction[188].

In addition to offering physical and virtual reverse flows at most cross-border interconnection points, several **new cross-border interconnectors** have been built, particularly in Central and South-East Europe (see Figure 4.2). These new interconnectors have been essential in **linking previously isolated infrastructures** of the Baltic states and South-East Europe to the rest of the European market.

Figure 4.6: Key cross-border infrastructure completed to diversify away from Russia



Source: Authors' own elaboration.

[187] After the April 2014 backhaul capacity in the Yamal pipeline (Mallnow) and the upgrading of the Lasów IP enabled an increase in both virtual and physical gas imports from Germany.

[188] A detailed overview of the advancement on CEE and SEE interconnection: ACER and CEER, 2014, *Annual report on the Results of Monitoring the internal Electricity and Natural Gas Markets in 2013. Gas Wholesale Markets Volume*. Pp. 255-261. Available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf.

The so-called **Southern gas corridor** that consists of the Trans-Anatolian and Trans-Adriatic (TANAP-TAP) pipelines brought supplies from Azerbaijan to several countries in South-East Europe and Italy in 2020. Equally, some projects such as the Azerbaijan–Georgia–Romania (AGRI) pipeline to bring Caspian gas to Romania never materialised. Others have been delayed for a long time. Completed in late 2022, the Interconnector Greece-Bulgaria (IGB) had experienced various delays and took almost 10 years, although it had remained crucial to remove Gazprom's monopoly in the region and particularly Bulgaria – and now to source Bulgaria with alternative supplies, such as piped gas from the TAP and LNG terminal in Greece.

In the **Baltic region** and **Poland**, new interconnectors – the Balticconnector between Estonia and Finland (2020), the Gas Interconnector Poland Lithuania (GIPL, 2022), and the LNG terminals in Klaipeda (2014) and Swinoujscie (2016) – reduced the region's dependence on Russian gas supplies. Along with increasing interconnectedness across Member States, Russian gas export monopoly Gazprom was no longer able to *fully* exert monopolistic market power in these regions. Among the most recently completed, the Baltic Pipe, commissioned in September 2022, connected Norwegian gas fields with Poland via Denmark. The Poland-Slovakia interconnector[189] inaugurated in August 2022 will further contribute to integrating landlocked Central European states and Ukraine with Poland and will allow sourcing volumes from both the Baltic Pipe and LNG terminals located on the Baltic coast. The STORK II gas interconnection project between Poland and the Czech Republic had been suspended in 2020 after years of deliberations, but recently the two countries renewed their cooperation on this interconnector[190].

4.1.3. LNG terminals

LNG has been viewed as one of the key components in ensuring diversification of the EU's gas markets already in an EU strategy for liquefied natural gas and gas storage[191] adopted in 2016. After the decision to phase out gas imports from Russia was stipulated in the REPowerEU in March 2022 and later confirmed in the REPowerEU Plan in May 2022, LNG has become pivotal in securing an appropriate level of natural gas imports into the EU during the transition period towards the 2050 climate neutrality.

Existing import capacity

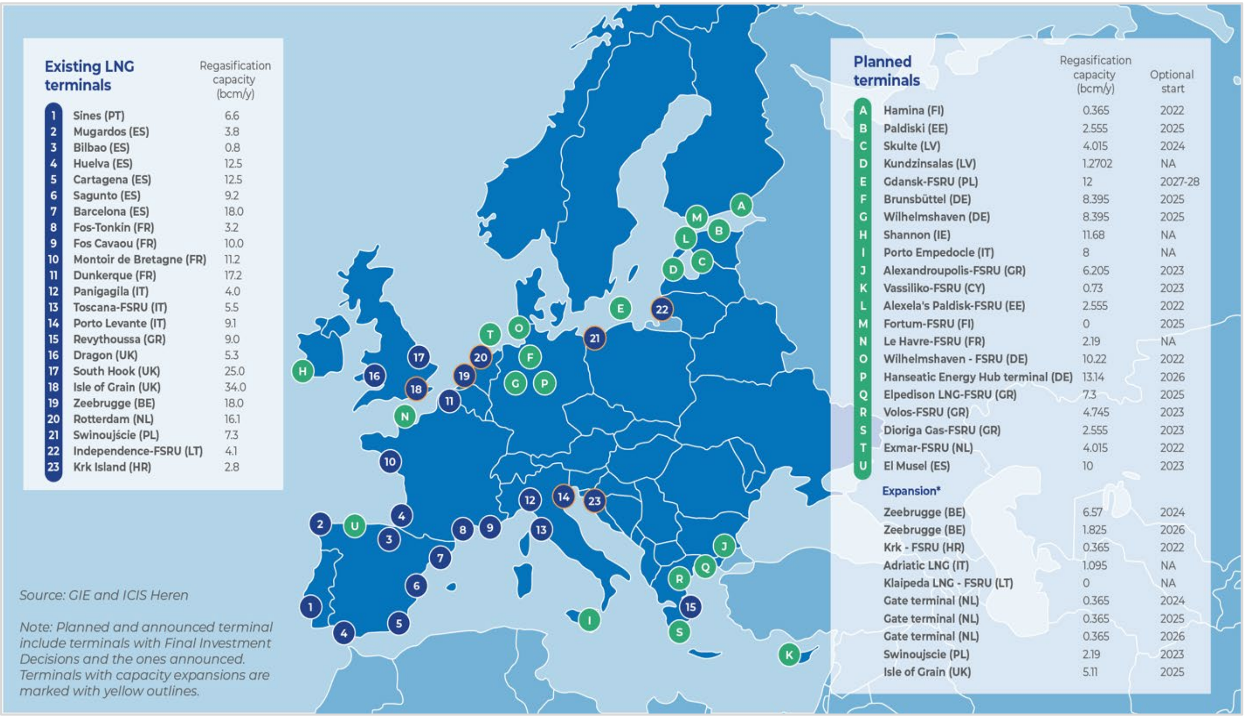
By January 2022, 20 LNG terminals operate in the EU-27 with an approximate cumulative capacity of 2300 TWh, or about 157 bcm (Figure 4.3).

189 European Commission 2022, Inauguration of the gas interconnector between Slovakia and Poland, 26 August. Available at: https://ec.europa.eu/info/news/inauguration-gas-interconnector-between-poland-and-slovakia-2022-aug-26_en.

190 Reuters, 2022, *Czechs, Poles ask for EU funding for revived gas interconnector project*. 30 September. Available at: https://www.reuters.com/markets/europe/czechs-poles-ask-eu-funding-revived-gas-interconnector-project-2022-09-30/.

191 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on an EU strategy for liquefied natural gas and gas storage COM/2016/049 final.

Figure 4.7: LNG terminals – operational and planned – Q2 2022



Source: ACER/CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume.*

LNG terminals are unequally distributed across the EU, as most operational LNG terminals are located in the Iberian Peninsula, Italy, France and North-West Europe (see Figure 4.3 which provides an assessment of LNG capacity across Member States by ACER and CEER (2022) and Table 4.1 which offers an assessment by GIE). The regions of South Eastern Europe, Central and Eastern Europe and the Baltic region historically relied on pipeline gas shipped from Russia and only in recent years started construction of LNG terminals to reduce dependence on Gazprom's supplies. These regions still have limited access to LNG. For a long period, Germany also relied on pipeline gas shipped from Russia and currently has no LNG facilities.

In terms of technical potential, the Iberian Peninsula contains the largest pool of LNG terminals, which accounts for about 25% of the EU-27 LNG capacity. However, limited gas pipeline interconnection with France and the absence of interconnection with the other EU Member States limit the use of these terminals on a bigger scale to ship gas across the EU. By September 2022, the utilisation rate, except for Sines LNG in Portugal, has remained rather low.[192]

The second largest LNG capacity of about 15% of EU-27 is located in France; Italy comes third with 8% of EU-27). Rotterdam LNG in the Netherlands and Zeebrugge LNG in Belgium bring LNG into North-West Europe. On the Baltic coast, only recently, two terminals were completed – Swinoujscie LNG in Poland (since 2016) and Klaipeda LNG in Lithuania (since 2014) marking a substantial step in diversifying gas supplies to the Baltic region and Poland. There are also several small-scale LNG terminals and bunkering facilities across the Baltic and Nordic regions. LNG terminal in Tornio on the

[192] The utilisation rates of three Spanish terminals on the Atlantic coast attained only about 20%, and of the terminals located on the Mediterranean Sea 33% in 2022.

Gulf of Bothnia in Finland and Gothenburg LNG in Sweden serve only off-grid deliveries without using regasification units as there is no gas pipeline connection in the area.

In South-Eastern Europe, there had been only one LNG terminal, Revithoussa LNG in Greece, for more than two decades, until the Krk terminal in Croatia started commercial operation in January 2021.

Table 4.3: Operational LNG terminals in the EU Member States, April 2022

Country	LNG terminal	Start-up year	Type	Capacity, bcm/year
Belgium	Zeebrugge LNG Terminal	1987	large onshore	11.40
Croatia	Krk LNG Terminal (LNG Croatia)	2021	FSRU	2.60
France	Dunkerque LNG Terminal	2016	large onshore	13.00
France	Fos Cavaou LNG Terminal	2010	large onshore	8.50
France	Fos-Tonkin LNG Terminal	1972	large onshore	1.50
France	Montoir-de-Bretagne LNG Terminal	1980	large onshore	10.00
Greece	Revithoussa LNG Terminal	1999	large onshore	7.00
Italy	OLT Offshore LNG Toscana FSRU	2013	FSRU	3.55
Italy	Panigaglia LNG Terminal	1971	large onshore	3.40
Italy	Porto Levante (Adriatic) LNG Terminal	2009	offshore GBS (Gravity Based Structure)	8.58
Lithuania	Klaipeda LNG (FSRU Independence)	2014	FSRU	4.00
Malta	Malta Delimara LNG terminal (Armada LNG Mediterrana)	2017	FSU + onshore regasification	0.70
Netherlands	Gate terminal, Rotterdam	2011	large onshore	12.00
Netherlands	Eemsenergy terminal	2022	FSRU	8.00
Poland	Swinoujscie LNG Terminal	2016	large onshore	6.20
Portugal	Sines LNG Terminal	2004	large onshore	7.60
Spain	Barcelona LNG Terminal	1969	large onshore	17.10
Spain	Bilbao LNG terminal	2003	large onshore	7.00
Spain	Cartagena LNG Terminal	1989	large onshore	11.80
Spain	Huelva LNG Terminal	1988	large onshore	11.80
Spain	Mugardos LNG Terminal	2007	large onshore	3.60
Spain	Sagunto LNG terminal	2006	large onshore	8.80

Source: GIE.

Utilisation rates

Available LNG technical capacity in the EU is sufficient to satisfy almost 60% of the EU gas demand of 4025 TWh (2021). However, for years, LNG imports had remained rather low having reached around 20% of the EU gas portfolio by 2019, and in the first half of 2022 – the record 30%[193].

[193] Including the UK. ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*. July 2022.

The volatility of LNG imports into the EU is closely linked to the global supply side, such as global competition for spot cargoes or LNG prices relative to other gas sourcing options. To large extent, the volumes of LNG cargo sent to Europe are determined by the price spreads between Europe and Asian gas markets. Thus, in Q1-3 2021 spot LNG cargoes went to Asian-Pacific markets supported by their premium and to other countries that increased LNG imports. In Q4 2021 EU LNG imports revived following increased global supply and lower imports from Asia. Since February 2022, LNG imports into the EU grew to their historical highs due to a need to substitute pipeline imports from Russia. Compared to May-August 2021, in late Spring 2022, LNG imports increased by 40%, bypassing piped gas in the EU's import portfolio due to significantly increased US spot deliveries [194]. Worth noting that Russian LNG supplies to the EU also increased in the same period, reaching 5% of the total gas supply portfolio compared to 3.9% in 2021 [195].

The high price responsiveness of LNG spot and short-term cargoes adds to the relative irregularity of EU LNG imports. These fluctuations explain to large extent the low **utilisation rates of EU LNG terminals**. On average, they remained particularly low during the 2010s and grew up during the so-called 'gas glut' of 2018-2020 when markets were oversupplied and spot cargoes were diverted to Europe as a "last resort market". In 2020, the EU average utilisation rate reached its historic maximum slightly decreasing in 2021 up to 38%. During the first half of 2022, the average utilisation rate skyrocketed to above 60% as LNG deliveries to the EU grew. However, in the current geopolitical conditions, certain adjustments to the volatility of the LNG market are under discussion. Among others, In a joint statement following a meeting of the EU-US taskforce on energy security in Washington on 3 November 2022, the EU and USA welcomed LNG supplies from the USA to be upscaled by an additional 50 bcm next year and agreed to work on how to ensure "security of supply and storage filling in 2023 at prices reflecting economic fundamentals"[196].

In addition to the global side of supply, other factors also account for terminal utilisation and the shippers' choices for directing cargoes to particular LNG terminals. **Contractual provisions** and **regulatory settings** of LNG terminals also affect the procurement of LNG.

The differences between terminals utilisation in the Member States in 2021 highlighted that the terminals, at which **long-term capacity contracts** tend to prevail, i.e. Portuguese, Polish and selected Italian and French terminals, had higher capacity utilisation. Longer-term booking is commonly used at the newly built and exempted terminals.[197] In many cases, long-term capacity booking derives from the participation of LNG exporters, such as Qatar Petroleum in Belgian Zeebrugge or Italian Adriatic LNG. Arguably, longer-term capacity booking also allows for better security of supply imbuing customers from spot cargo fluctuations. From the other point of view, providing more options to access shorter-term capacity slots may allow necessary space for market rebalancing.

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[194] In the first half of 2022, US cargoes increased up to 14.8% in the EU and UK gas supply portfolio – a significant rise from 5.5% in 2021.

[195] Including the UK. ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas* Markets in 2021. Gas Wholesale Markets Volume. July 2022. P.19. This was also confirmed by Commissioner Simpson during an exchange of views on 4 October 2022 with the ITRE Committee. Russia did not discontinue LNG gas, which is sold at very high spot market prices on the global market, including Europe. Available at: https://multimedia.europarl.europa.eu/en/webstreaming/committee-on-industry-research-and-energy_20221004-2000-COMMITTEE-ITRE.

[196] The White House, 2022, 7 November, Joint Readout of U.S.-EU Task Force Meeting on Energy Security. Available at: https://www.whitehouse.gov/briefing-room/statements-releases/2022/11/07/joint-readout-of-u-s-eu-task-force-meeting-on-energy-security/.

[197] ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*.

Although since the beginning of 2022, there have been substantial shocks in gas markets that could urge to secure more longer-term provisions, including in capacity booking, there is still a need to ensure sufficient space for shorter-term LNG purchases. With a growing share of renewables in the energy mix, more flexibility will be needed for natural gas to balance the power market for renewables' intermittency.

Utilisation rates are also affected by the regulatory framework of LNG terminals. The EU Gas Directive (2009) obliges LNG terminals to ensure a regulated TPA with transparent and non-discriminatory access. However, the Directive also left 'a significant degree of discretion to the regulated terminal operators' regarding capacity allocation, anti-hoarding procedures and services provided'[198]. As a result, LNG terminals operate under varying terminal codes, which are developed by terminal operators, guidance by National Regulatory Authorities and exemptions if granted. **Terminal services and tariffs** and the trading opportunities at their linked hubs[199] may contribute to shippers' decisions to direct cargoes to one or another terminal. While long-term capacity booking provides certain predictability in the usage of terminals, in the case of spot cargoes, these services and associated technicalities may play a role in affecting shippers' decisions. According to ACER and CEER (2022), not all capacity arrangements at terminals allow accommodating spot cargoes by acquiring primary capacity at short notice.

Diverse access regimes exist in the EU. In line with the EU Gas Directive (2009), LNG terminals shall ensure a regulated TPA with transparent and non-discriminatory access to the terminals. TPA exemption for LNG infrastructure is allowed only under certain conditions and a related approval by the European Commission. Regulatory aspects that govern their **access** are increasingly debated as cross-terminal competition across the EU is on the rise. In market terms, a TPA exemption allows long-term contracts for capacity use and allows project developers to back their business case. Three terminals with exemptions, i.e. Adriatic LNG, Dunkerque LNG and Rotterdam's Gate terminal, have relatively higher utilisation rates. However, one may raise the question of whether these exemptions create market distortion and more harmonisation might be needed[200]. Worth noting, forthcoming terminals in Greece and Germany obtained only a partial exemption (Table 4.2).

Table 4.4: TPA exemptions for LNG terminals in the EU, 2022

LNG TPA exemptions	Country	Decision year	Period of exemption	Notes
Adriatic LNG (Rovigo)	IT	2005	2010-2035	80% of capacity is exempted
Dunkerque	FR	2010	2017-2037	Gradual opening from 2021
		Revised in 2022	2023-2036	Long-term capacity booking cannot bypass 61% of capacity
Gate terminal	NL	2007	2011-2031	More than 51% of capacity to a dominant supplier is forbidden
Alexandroupolis	GR	2020	2023-2027	32% of capacity is open to the market
			2027-2033	39% of capacity is open to the market
			2033-2037	62% of capacity is open to the market
Hanseatic Energy Hub	DE	2022	2026-2051	To be followed

Source: European Commission list of approved TPA exemptions, 2022.

198 For a detailed discussion see Yafimava, K., 2020, *Finding a home for global LNG in Europe: understanding the complexity of access rules for EU import terminals*. Oxford Institute for Energy Studies. Available at: https://www.oxfordenergy.org/publications/finding-a-home-for-global-lng-in-europe-understanding-the-complexity-of-access-rules-for-eu-import-terminals/.

199 ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*. July 2022. Here p. 45.

200 For a detailed discussion see: *Study on EU gas market upgrading and modernisation – Regulatory framework for LNG terminal*, prepared for the European Commission by Trinomics, REKK and Enquidity, 2020.

Planned LNG terminals

Although various projects for new LNG terminals across the EU have been discussed in recent years, in 2022, as a rapid reaction to the ongoing energy crisis, many Member States come up with numerous plans to install floating storage and regasification units (FSRU), expand the capacity of existing terminals and build new onshore terminals. Yet, the calculation and reporting of planned capacity vary across sources (compare Table 4.3 and Figure 4.3), and some projects might be on the shelf. According to FTI Consulting (2022)[201], since the start of the war in Ukraine, many new projects were launched and the previously announced projects accelerated with a new total regasification capacity of about 97.4 bcm, including Germany with over 50% dependence on Russian gas in 2021, Italy with about 40% of dependence and Finland and Estonia with almost 100% dependence. Table 4.3 summarises the projects and their stages as identified by FTI Consulting (2022) and GIE.

Table 4.5: LNG terminals in EU Member States – planned and under construction, 2022

Country	Name of installation	Status	Investment	Start-up year	Type	Capacity, bcm/y
Projects under construction in the EU						
Belgium	Zeebrugge LNG Terminal	under construction	expansion	2024	large onshore	3.90
Belgium	Zeebrugge LNG Terminal	under construction	expansion	2026	large onshore	1.80
Cyprus	Vasiliko LNG terminal	under construction	new facility	2023	FSRU	2.44
Greece	Alexandroupolis LNG terminal	under construction	new facility	2023	FSRU	5.50
Netherlands	Gate terminal, Rotterdam	under construction	expansion	2024	large onshore	1.50
Poland	Swinoujscie LNG Terminal	under construction	expansion	2023	large onshore	2.10
Projects that could be considered already advanced before the Russian invasion of Ukraine						
France	Fos Cavaou LNG Terminal	planned	expansion	2022	large onshore	7.40
France	Fos Cavaou LNG Terminal	planned	expansion	2030	large onshore	2.00
Greece	Dioriga Gas FSRU	planned	new facility	2023	FSRU	2.50
Latvia	Skulte LNG terminal	planned	new facility	2023	FRU + direct link to UGS	1.50
Netherlands	Gate terminal, Rotterdam	planned	expansion	2026	large onshore	2.50
Poland	GDANSK LNG	planned	new facility	2025	FSRU	6.10
Projects that appeared or were re-launched after the Russian invasion of Ukraine						
Croatia	Krk LNG Terminal	planned	expansion	2029	FSRU	2.60
Finland-Estonia	Gasgrid	planned	new facility	2022	FSRU	
France	Le Havre	planned	new facility		FSRU	
Germany	Brunsbüttel LNG terminal	planned	new facility	2026	large onshore	8.00
Germany	Stade LNG terminal	planned	new facility	2026	large onshore	12.00

201 FTI Consulting, 2022, New LNG Regasification Terminals in Europe, pp. 14-16. Available at: https://www.fticonsulting.com/emea/-/media/files/emea--files/insights/white-papers/2022/may/new-lng-regasification-terminals-europe.pdf?rev=874e45a5757d45538a6b06f9ed0c1816&hash=1DEB35FF12B7E6BCF928778C383302A9.

Country	Name of installation	Status	Investment	Start-up year	Type	Capacity, bcm/y
Germany	Wilhelmshaven	planned	new facility		FSRU	10.00
Germany	Wilhelmshaven	planned	new facility	2025	FSRU	2.20
Greece	Thrace LNG	planned	new facility		FSRU	5.50
Greece	Argo FSRU	planned	new facility	2024	FSRU	5.20
Ireland	Shannon LNG FSRU	planned	new facility		FSRU	7.80
Ireland	Mag Mell FSRU	planned	new facility	2024	FSRU	2.60
Italy	FSRU 1 - SNAM	planned	new facility	2023	FSRU	5.00
Italy	FSRU 2 - SNAM	planned	new facility	2023	FSRU	5.00
Italy	Porto Empedocle (Sicilia) LNG terminal	planned	new facility		large onshore	8.00
Italy	Porto Levante LNG terminal	planned	expansion	2024	offshore GBS (Gravity Based Structure)	0.50
Netherlands	Eemshaven FSRU	completed	new facility	2022	FSRU	8.00

Source: GIE and FTI Consulting (2022). * capacity varies across the sources and is taken from the GIE database.

Although in light of the fast reduction of dependence on Russian imports, there is a strategic need to ensure enough capacity is available in terms of geographic distribution and volumes across the EU, several issues are worth addressing regarding numerous plans announced by the Member States to raise LNG capacity.

The rapid construction of LNG terminals justified by a need to fast-track the restructuring of the EU supply portfolio requires fast and streamlined **permitting** for LNG terminals. In the past, lengthy and varying procedures were reported consistently across the Member States. It might be worth noting that there is no single EU authority that facilitates the certification and permitting process of new LNG facilities. However, in the current political context, several Member States demonstrated high efficiency in terms of permitting, with the Netherlands as a blueprint. The approval of a new FSRU in Eemshaven was a matter of a few months; as the lease agreement was signed in the spring of 2022, the first deliveries commenced less than six months after. Germany seems to follow the Dutch example by approving new FSRUs by January 2023, and three more by the end of 2023. Further, in the current regulatory context, it is important to ensure a fast connection of the FSRUs to the pipeline infrastructure.

Overcapacity may be created as **gas demand is expected to decrease**[202] in the next decades in line with EU decarbonisation targets. Gas demand may be also significantly capped both due to demand destruction and relevant regulatory measures adopted inter alia in the 'Save Gas for a Safe Winter' package. Some newly planned FSRUs or expansion of onshore terminals are essential to provide access to LNG in some markets, as in the case of a new FSRU for Finland and Estonia, or to bring additional volumes to the market, such as in North-West Europe, where utilisation rates of LNG terminals are relatively high already and an increase in imports is expected to be shipped to Germany and adjacent markets. FSRUs and onshore terminals are also crucial for Germany to replace supplies via Nord Stream 1. In many other cases, careful planning of additional LNG capacity may be useful.

[202] According to the IEA (2022 Q3 report), EU's gas consumption is set to decline by 10% by the end of 2022, Germany alone will reduce gas consumption by 20%.

Overcapacity can also occur as **a result of insufficient regional coordination** and alleged competition among the Member States. This is particularly the case in the Baltics and South-East Europe where an increasing number of projects are being announced. These decisions should be carefully matched with the market reality; in each case of new LNG facilities, additional investments are required into receiving ports, uploading and bunkering facilities, and the grid connecting with trunk pipelines. Reconciling the interests of all Member States concerned and market participants is essential but has proved to be challenging in the past.

Arguably, **FSRUs** could offer an advantage in terms of the energy transition and mitigation of stranded assets. Having shorter lead times compared to onshore terminals, they can be leased for a certain period until natural gas imports are needed on the market. As an increasing number of Member States are securing leasing agreements with FSRU providers, this spiking demand for FSRU facilities may face constraints for future deals; recent studies show that the FSRUs offer on the market is tight[203].

In the case of off-grid supplies, enhancement of **small-scale LNG**[204], such as bunkering, truck or rail LNG loading and virtual liquefaction, can be considered. Terminals that offer small-scale services could provide targeted solutions in some cases, such as Tornio LNG in Finland.

4.1.4. Underground gas storage

Covering around a quarter of the EU's annual gas consumption, Underground Gas Storage (UGS) is an important component in the European gas system providing security of supply and system flexibility by covering peak demand during the winter season. Storages allow commercial price absorption as well. In the context of steadily decreasing EU indigenous gas production and increasing import dependency, UGS, with other gas storage options[205], are becoming strategic serving as a buffer option in case of disruption[206]. For winter 2022/23, storage is also a 'minimal insurance' in case of full interruptions of Russian supplies.

Underground gas storage capacity and technical characteristics

The **total EU-27 gas storage capacity,** or working gas volume ('WGV'), is 1141 TWh (approx. 100 bcm), or about 27% of the EU-27 annual gas consumption. Gas storage supplies about 25-30% of the gas consumed in the EU during winter[207], Figure 4.4 shows the allocation and size of Member States' storage capacity and the share of their annual gas consumption it can cover.

[203] IEA, 2022, *Gas market report, Q3 – 2022*. Here p. 83. Available at: https://iea.blob.core.windows.net/assets/c7e74868-30fd-440c-a616-488215894356/GasMarketReport%2CQ3-2022.pdf; Natural Gas Intelligence, 2022, *Europe scrambling to secure floating storage for LNG supply*, 12 April. Available at: https://www.naturalgasintel.com/europe-scrambling-to-secure-floating-storage-for-lng-supply/.

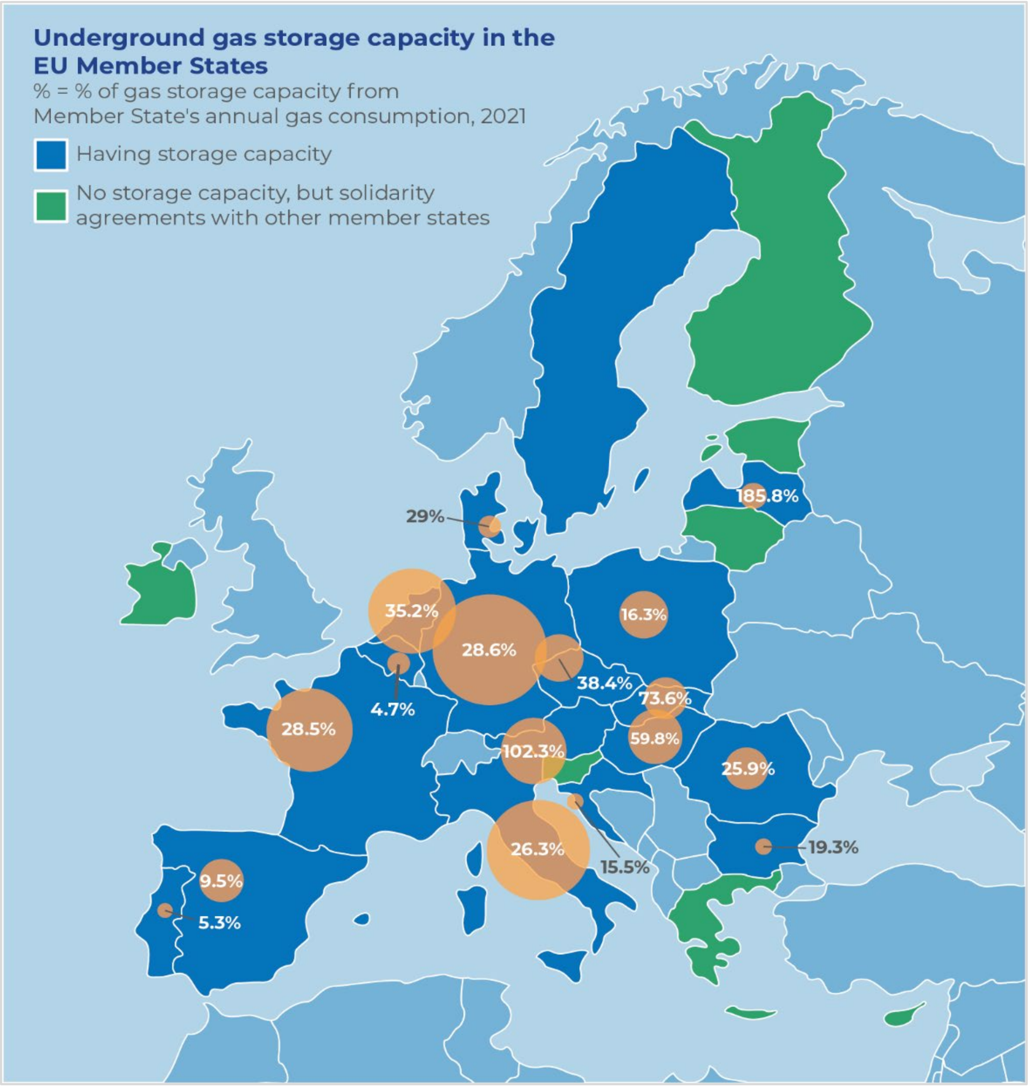
[204] CEER, 2022, *Liquefied Natural Gas Small-Scale Services in the European Union,* CEEP Report, Council of European Energy Regulators, Ref: C21-LNG-41-03.

[205] E.g. in liquid or gaseous form in above-ground tanks.

[206] ACER, 2022(a), *Report on Gas Storage Regulation and Indicators*, 7 April. Here p.6. Available at: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20Gas%20Storage%20Regulation%20and%20Indicators.pdf.

[207] Ibid.

Figure 4.8: Gas storage capacity in the EU Member States, 2021



Source: European Council, https://www.consilium.europa.eu/en/infographics/gas-storage-capacity/; ACER, 2022(a), *Report on Gas Storage Regulation and Indicators*.

UGS depends on various **geographical and geological factors**, thus not allocated evenly across the EU[208]. Box 4.2 shortly describes the different types of UGS and their role in the security of supply. For a detailed assessment of types of storage and the share of UGS in Member States' annual gas consumption, see Annex 1.

[208] 18 Member States have gas storage facilities on their territory; two thirds of the EU's total gas storage capacity are located in five countries (Germany, Italy, France, the Netherlands and Austria). Austria's and Latvia's storage capacity exceeds the countries' national gas consumption and is used at the regional level serving adjacent countries. 9 Member States without storage (Cyprus, Estonia, Finland, Greece, Ireland, Lithuania, Luxembourg, Malta, and Slovenia) account for less than 5% of EU-27 annual gas consumption. Source: ACER, 2022(a), *Report on Gas Storage Regulation and Indicators*, 7 April 2022.

Box 4.6: Types of underground gas storage

Underground natural gas storage facilities are largely classified into **three main types**: depleted fields, aquifers and salt caverns. They vary by their geological conditions, deliverability rate, i.e. the rate at which this gas can be withdrawn, and the share of cushion gas, i.e. amount of gas that is permanently stored in the facility to maintain sufficient pressure and allow injections and withdrawals.

Depleted fields – former natural gas reservoirs – are the main type of storage both globally and in the EU, which require about 50% of cushion gas. **Aquifers** are underground permeable rock formations that served as water reservoirs and are repurposed as natural gas storage facilities. The share of cushion gas reaches up to 80% of their total volume. **Salt caverns** are storages artificially created in underground salt formations via solution mining. They typically require around 33% of the cushion gas.

Depleted fields and aquifers are mainly used to balance **seasonal swings in gas demand** as they allow for large storage but relatively low injection and withdrawal rates due to their geophysical properties. Salt caverns allow gas withdrawals at higher rates and thus are used primarily to **optimise gas portfolios in the shorter term**. Arguably, market liberalisation requires higher flexibility and stimulates salt cavern storage. Most gas storage capacity of Member States is composed of depleted fields and aquifers, except Portugal and Sweden, where only salt caverns are present. **Salt caverns** storages are present in 8 Member States but still is only **a fraction of the total UGS** capacity (also as they require large, underground salt formations), except in **Germany** where the salt domes are well present in the northern and central parts.

Source: Cedigaz Insights, 2019, *Underground gas storage in the world – 2019 status*.

In recent years, gas storage capacity decreased marginally as a result of decommissioning storage facilities in Germany, Ireland and the UK – the trend that results "from the existing economic environment for the gas storage market in Europe", according to the Gas Infrastructure Europe[209]. The closure of Rough UGS in the UK, off the east coast of England, in 2017 resulted in a sharp reduction of the UK storage capacity[210]. This UGS site is currently under consideration for re-opening as it is reported to have received regulatory clearance[211].

Filling patterns of underground gas storage

Gas storage filling in the EU average has been about 80% on average during the last decade. The injection period usually starts in April and ends in October. In recent years, the **summer-winter spread**, i.e. a difference between summer and winter contracts, has been reducing and in 2022 is turning negative, whilst the cost of gas storage remained unchanged. This brought an additional financial burden on Storage System Operators (SSO), as well as added fewer incentives to replenish sites during the summer period.

During 2019-2020, UGSs were overfilled with cheap gas following the 'gas glut' on the global market and the COVID-19 pandemic. The winter season 2021/22, however, started with substantially lower stocks. On October 1, 2021, the average filling level reached only 72%, the lowest of a five-year average.

[209] GIE, 2018, Existing gas storage capacity in Europe exceeded one petawatthour in 2018, shrinked against 2016. Available at: https://www.gie.eu/press/existing-gas-storage-capacity-in-europe-exceeded-one-petawatthour-in-2018-shrinked-against-2016/.

[210] A depleted field with capacity of 3.31 bcm accounted for around 70% of UGS in the UK.

[211] Reuters, 2022, *Britain allows Centrica to reopen Rough gas storage facility*, 30 August. Available at: https://www.reuters.com/business/energy/britain-allows-centrica-reopen-rough-gas-storage-facility-2022-08-30/.

The relatively slower refilling was explained by several factors, including the hot summer of 2021 accompanied by several droughts across the globe, the Asian demand recovered after the pandemic, and high gas wholesale prices during the summer injection season, which did not incentivise market participants to store gas[212].

Russia's invasion of Ukraine in February 2022 led to an unprecedented situation when storage needed to be filled at extremely high gas prices during the summer period and the so-called 'negative spread' between summer and winter gas prices. Moreover, the winter season ended with the lowest level of UGS (26% on 1 April 2022). Despite that difficulties, the EU average gas storage filling exceeded 80% by 1 October and 90% by the end of October 2022, although injections remain slower in some Member States[213].

The regulatory framework

Over the years, the UGS was arguably not in the spotlight of EU regulation, and the EU Gas Directive (2009) did not prescribe detailed regulation on storage functioning. Storage system operators (SSOs) were also not subject to unbundling and were not obliged to undergo a strict certification process, similar to the one gas transmission networks shall follow.

National regulatory frameworks for UGS varied significantly across the Member States. Several studies prepared for the Commission assessed these differences in detail[214]. Table 4.4 shows **the differences in stock levels** among the Member States in 2021 were higher than in the previous five years. Storages had higher filling rates in the Member States with regulated TPA as the regime access[215]. Also, in the Member States where anti-hoarding rules apply, filling levels were higher. 94% of the total EU UGS capacity was booked in 2021 but lower filling rates were observed across the Member States. In Austria, Germany, the Netherlands and Slovakia, a high percentage of storage capacity was booked but not filled. This led to capacity hoarding, i.e. the booking rates above the capacity usage.

Also, in 2021, unexpectedly low filling levels were observed in the UGS facilities (co)-owned by Gazprom. They are located predominantly in Germany, which applied negotiated access to UGS. It has been viewed by a number of experts that Gazprom's strategy to fill in UGS represented distortive behaviour.

Table 4.6: Gas storage in the Member States – regulatory framework, April 2022

	Booked storage 2021	Gas in storage 2021	TPA regime	Storage obligation	Strategic storage	Anti-hoarding rules
Austria	99%	53.6%	Negotiated			
Belgium	99.6%	87.2%	Regulated			Yes, UIOLI
Bulgaria	58.2%	70.5%	Regulated	Yes		
Croatia	100%	90%	Regulated			
Czech Republic	78.7%	77.3%	Negotiated	Yes		No
Denmark	83.1%	82.6%	Negotiated			

212 ACER, 2022(a), *Report on Gas Storage Regulation and Indicators*, 7 April. Here p. 6.

213 By the end of October 2022, filling levels remain below the 80% threshold in Latvia (54.7%) and Hungary (79.2%).

214 E.g. European Commission, Directorate-General for Mobility and Transport, *The role of gas storage in internal market and in ensuring security of supply*, Publications Office, 2017, https://data.europa.eu/doi/10.2832/568590.

215 In the regulated regime, storage is accessed based on third-party access ('TPA') and regulated tariffs; for the negotiated regime, access is negotiated based on transparent and non-discriminatory rules. By April 2022, 11 Member States established regulatory TPA and 7 had negotiated regime. Reportedly, regulatory changes are occurring in Austria and Germany.

	Booked storage 2021	Gas in storage 2021	TPA regime	Storage obligation	Strategic storage	Anti-hoarding rules
France	100%	92.3%	Regulated	Yes		Yes, UIOLI
Germany	96.7%	56.9%	Negotiated			No
Hungary	100%	83.7%	Regulated	Yes	Yes	Yes, UIOLI
Italy	90.7%	85.6%	Regulated		Yes	Yes, UIOLI
Latvia	86.7%	79.9%	Regulated			No
Netherlands	94.8%	58.5%	Negotiated			No
Poland	96.8%	96.3%	Regulated	Yes		
Portugal	87.7%	49.9%	Regulated	Yes	Yes	No
Romania	72.2%	72.6%	Regulated	Yes		Yes
Slovakia	92.6%	71.9%	Negotiated			No
Spain	74.3%	73.1%	Regulated	Yes		No
Total* **	**81.9%**	**72%**				

Source: ACER, 2022(a), *Report on Gas Storage Regulation and Indicators*.

As a response to unprecedentedly low gas stocks, in the '**EU Hydrogen and Decarbonisation Gas Market Package**', the Commission proposed various voluntary measures that the Member States can take based on the common risk assessment and subject to consultation with risk groups. They included an option to impose minimum storage obligations, introduce incentives for gas storage bookings, and integrate storage into the transmission system of network operators. The proposed revisions of Regulation 2017/1938 also included a voluntary option of joint procurement of strategic stocks of natural gas. This option implied Member States could coordinate purchasing of gas in line with EU competition rules[216].

Following Russia's invasion of Ukraine in February 2022, the Commission offered a rapid response in the Communication REPowerEU.[217] On 23 March 2022, the Commission tabled a legislative proposal introducing **a minimum of 80% gas storage level obligation** by 1 November for Winter 2022/23, rising to 90% for the following years and **obligatory certification of SSOs**. Followed by less than three months of discussions, on 27 June 2022, the proposed measures were adopted by the Council in a new **Regulation 2022/1032** on gas storage to impose minimum storage level and obligatory certification of storage system operators.

These policy developments renewed attention to the long-standing debate about how to reconcile **market value and insurance value** of storage and ensure the security of supply component of the gas storage business[218]. The key issue that was raised during various discussions is an imbalance between reliance on storage for exceptional security circumstances and SSOs business covering the costs. Since late 2021, the long-lasting debate about the market vs collective/system value has been brought from the national to EU perspective and will shape further policy discussions on the topic in upcoming years.

Some experts raised concerns that EU gas undertakings cannot rely solely on market any longer in light of the extreme circumstances, and there is a need to adopt obligatory storage. However, despite all

216 Kneebone, J., 2022, A first look at the EU Hydrogen and Decarbonised Gas Markets Package. 16 December. Available at: https://fsr.eui.eu/a-first-look-at-the-eu-hydrogen-and-decarbonised-gas-markets-package/.

217 For a detailed overview of the proceedings: Wilson, A., 2022, *New EU regulation on gas storage*. Briefing, European Parliamentary Research Service, June. Available at: https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/729393/EPRS_BRI(2022)729393_EN.pdf.

218 For an overview, see: Conti, I., 2022, *All eyes on gas storage. Florence School of Regulation*. 25 July. Available at: https://fsr.eui.eu/the-role-of-gas-storage/; FSR, 2022, A regulatory framework for gas storage. Florence School of Regulation, 6 April, online event. Available at: https://fsr.eui.eu/event/a-regulatory-framework-for-gas-storage/.

impediments, market participants managed to fill in EU UGS during the summer of 2022 surpassing 80% of the EU average by October 2022. Some proposals referred to a system of strategic gas reserves, similar to the IEA or EU strategic petroleum reserves [219]. Obligatory storage or strategic stocks ensure gas availability in emergency cases but incur higher costs and sterilise the capacity. This also brings a question about how to ensure solidarity among SSOs, which are nationally regulated. One may argue that strict storage obligations may be costly incentivising the protection of national markets.

In addition to the security function, UGS is also tasked to provide flexibility. Certain flexibility in storage regulation may need to be maintained to provide its functioning with a market-based mechanism[220]. Commercial storage also plays an important role in the decentralisation and decarbonisation of the entire energy system. It might be important not to curb flexibility, also in the short-term, especially with increasing LNG inflows. Alternatively, risks of capacity hoarding may emerge. As well, various types of UGS perform different roles; for example, salt caverns are used for high-rate withdrawals several times per year. Flexibility might be needed also in the case of defining Member States' filling trajectories and retaining the capacity to react to gas price fluctuations. Experience that will be obtained during 2022/23 should carefully assess the most efficient options.

4.2. REPowerEU: Addressing remaining bottlenecks via smart investment

In recent years, as discussed in section 4.1, a number of infrastructure projects have been implemented under the Trans-European energy networks (TEN-E) framework and co-financed by the EU. Among the projects that significantly improved interconnectedness, bridged previously isolated markets, and brought alternative supplies to regional markets are: Gas Interconnector Poland Lithuania (2022), Balticconnector (2019), Baltic Pipe (2022), Trans Adriatic Pipeline (2020), IGB (2022), and LNG terminals – Klaipeda LNG (2014), Swinoujscie LNG (2016) and Krk LNG (2021).

Several gas PCIs are expected to be completed in the upcoming years. Among others, the REPowerEU plan estimates Cyprus LNG terminal[221] in Cyprus and Alexandroupolis FSRU in Greece to become operational in 2023. As well, in the coming years, Gdansk LNG in Poland is planned to become operational by 2026, and several underground gas storage projects in Bulgaria, Greece and Romania are to be completed.

In addition, a significant re-orientation of gas flows following Russia's invasion of Ukraine requires not only the implementation of the already planned gas infrastructure projects, some of them long-pending but also the urgent address of the **emerging congestions due to the replacement of Russian flows**. Several infrastructure bottlenecks have been identified in the latest ENTSOG EU Summer Energy Supply Outlook[222]. The RepowerEU Plan estimates that this 'limited additional infrastructure' (i.e. LNG import terminals, pipelines to connect underutilised LNG terminals and the network and reverse flows) will **require targeted investment estimated at EUR 10 billion by 2030**.

[219] For example, see: Gros, D., 2022, *A (E)U-turn from Nord Stream 2 towards a European Strategic Gas Reserve*. Available at: https://www.ceps.eu/ceps-publications/a-eu-turn-from-nord-stream-2-towards-a-european-strategic-gas-reserve/.

[220] For example, see the proposal by the Florence School of Regulation: Conti, I, 2022, *All eyes on gas storage*. Available at: https://fsr.eui.eu/the-role-of-gas-storage/.

[221] Also called Cynergy FSRU or Vassiliko FSRU, in the name of the port where it will to be located.

[222] ENTSOG, 2022, EU Summer Energy Supply Outlook. Available at: https://www.entsog.eu/sites/default/files/2022-04/SO0035-22_Summer_Supply_Outlook_2022_BOA_Rev8.1_220427%20for%20publication.pdf.

It also underlines that once new gas projects are included in the new REPowerEU chapters of the NRRPs, Member States need to prioritise a regionally coordinated approach and the projects already identified in the RepowerEU Plan[223].

Relying on the recent ENTSOG simulation, the **REPowerEU Plan** (Annex 3) lists the additional gas infrastructure needed to unlock the emerged **congestion points**. Most of these congestion points relate to the redirection of flows from North-West Europe to Germany and Central Europe to replace Russian supplies. Based on the REPowerEU plan's estimations and relying on the discussions with stakeholders and experts interviewed, the following key bottlenecks are viewed to be addressed (Figure 4.5).

Figure 4.9: Key infrastructure bottlenecks, 2022

Source: authors' own elaboration.

[223] A need of additional public funding for new natural gas projects has been challenged by several environmental NGOs. E.g. in their study, Bellona Europa, Ember, RAP and E3G argue that 'security of supply and reduction of Russian gas dependence does not require the construction of new EU gas import infrastructure such as LNG terminals'. Bellona Europa, Ember, RAP and E3G, 2022, EU can stop Russian gas imports by 2025, Briefing. Available at: https://network.bellona.org/content/uploads/sites/3/2022/03/EU-can-stop-Russian-gas-imports-by-2025-Final.pdf.

- Regulatory incompatibilities between **French and German gas systems** restricted direct flows from France to Germany, as France (and Spain) odorise natural gas in their transmission systems for safety reasons to better detect leakages. This regulatory incompatibility prevented gas flows from France to Germany, and no significant capacities are available at the French-German border. Following a public consultation by the CRE, a French NRA, GRTgaz, the French gas TSO, was able to commission the reverse flow to Germany in October 2022.[224] A deodorisation unit and physical reverse flow at the French-German interconnector (Obergailbach-Medelsheim) would further enable physical flows in the direction of Germany but it would require months to be completed (see section 4.3.1);

- Due to its high reliance on Russian gas and high domestic gas demand, **Germany** urgently needs to commission LNG regasification capacities. In case Russian gas flows would be further reduced or interrupted via the only remaining route to Germany via Ukraine, Germany will have limited options to source alternative supply to meet its demand. Several FSRUs and onshore LNG terminals are in the pipeline in Germany (see section 4.3.1);

- Significant LNG import capacity is located in the **Iberian Peninsula**, but Spain and France are connected only with a small interconnector, which is insufficient to bring substantial LNG to the rest of Europe. Interconnectors to better link France and Spain had been in discussion for many years; the MidCat pipeline was cancelled in 2019 due to disagreements between the countries, reappeared in the current discussions, but was definitively abandoned by Spain and France in October 2022. Instead, the two countries agreed to cooperate on the green energy corridor and a new pipeline linking Barcelona to Marseille[225]. Several other options to unlock Spanish gas import capacity are under discussion as well, including an offshore pipeline to connect Spain and Italy (see section 4.3.1);

- Substantial progress has been achieved in connection with **the Baltic region** with **Poland** and further Central Europe. However, the LNG import infrastructure in the Baltic region needs to be complemented by an additional FSRU to be located in Finland or Estonia, which is ongoing.[226] The second terminal in Poland (Gdansk LNG), which is on the 5th PCI list, will further improve the security of supply in the medium term. Furthermore, the new Baltic Pipe project commissioned on 28 September 2022 connected Poland to Norwegian gas fields via Denmark. The expansions of the Polish-Ukrainian route and the completion of the Poland-Slovakia interconnector could allow Central Europe and Ukraine to access LNG imports via Poland (see section 4.3.2); and

- In **Central and South-East Europe,** a number of projects remain essential to be completed. Ongoing PCIs of the Trans-Balkan Corridor (Turkey-Bulgaria-Romania) and the Vertical Corridor (Interconnector Greece-Bulgaria, Romania-Bulgaria interconnector and BRUA) will facilitate the supply of gas from third countries in the region. The Interconnector Greece-Bulgaria has been inaugurated in October 2022 and will connect Bulgaria, which was 100% dependent on Gazprom, with physical LNG supplies from Greece and with piped imports from Azerbaijan.

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[224] S&P Global, 2022, *France begins physical gas flows to Germany at Obergailbach: GRTgaz*. 13 October. Available at: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/101322-france-begins-physical-gas-flows-to-germany-at-obergailbach-grtgaz.

[225] Euractiv, 2022, *Spain, France, Portugal abandon MidCat, agree on green energy, gas corridor*. 21 October. Available at: https://www.euractiv.com/section/energy/news/spain-france-portugal-abandon-midcat-agree-on-green-energy-gas-corridor/.

[226] RepowerEU Plan, Annex 3, p.8.

The reinforcement of the Southern Gas Corridor is also flagged as a priority in the REPowerEU. The expansion of the Trans Adriatic Pipelines (TAP) is also under consideration to bring additional gas volumes from Azerbaijan to South-East Europe and Western Balkans. However, this might require an upgrade of the Italian transmission network to allow the flows from the South to the North of Italy (see section 4.3.3).

4.3. Region-specific infrastructure bottlenecks

Following the outline of the key bottlenecks in section 4.2, this section will discuss the regional specificities and elaborate on particular bottlenecks as identified in the REPowerEU plan and during the interviews with stakeholders.

4.3.1. Bringing LNG from the Iberian Peninsula

With significant spare LNG capacities, the Iberian Peninsula has immediately attracted a lot of attention as one of the options to supply Germany and/or Central and Eastern Europe by redirecting LNG imports from Spain via France. However, the Iberian Peninsula remains an **'LNG island' with only limited interconnector capacity** available between Spain and France. The **MidCat pipeline**, a larger interconnector between France and Spain, had been discussed for years and recently re-appeared on the agenda, but was cancelled at the end of October 2022. Instead, France and Spain agreed to pursue a 'green corridor', a **BarMar pipeline** to connect Barcelona and Marseille. That raises concerns that LNG imports into the Iberian Peninsula could contribute to the current crisis and redirect to other Member States in the nearby future[227].

Gas import structure in the Iberian Peninsula

With the largest LNG capacity, Spain imports LNG from six terminals[228] (see section 4.2) with increased activities in recent months. Worth noting, in 2022, LNG supplies by Novatek (Russia) to Spain increased substantially and scored second after US LNG imports[229]. Still, the utilisation rate was not higher than 50% in all LNG terminals except one[230], arguably considering the isolated gas markets of Spain and Portugal. The adjacent market of Portugal is connected with Spain with a small interconnection. Some flows are exported to Spain but the interconnector between Portugal and Spain remains under-used whilst LNG utilisation rates of Sines LNG in Portugal are higher than the European average, partly due to its low import capacity that covers almost the entire gas demand in the country.

In addition to LNG infrastructure, Spain and Portugal receive piped gas from **Algeria** – which flows have undergone substantial changes since late 2021. The contract to transit gas through the Maghreb-Europe interconnector via Morocco into the Iberian Peninsula expired in October 2021. In light of the political context between Morocco and Algeria[231], the contract was not renewed. Sonatrach, the national state-owned oil company of Algeria, redirected the routes partially to the Medgaz interconnector, connecting Algeria directly with Spain, which was used almost at its nominal capacity since 2022. However, the fact that the remaining export pipelines to Spain (via the Medgaz pipeline)

[227] Euractiv, 2022, *France trades MidCat pipeline for an already controversial new Project*. 21 October. Available at: https://www.euractiv.com/section/energy/news/france-trades-midcat-pipeline-for-an-already-controversial-new-project/.

[228] Mugardos, Bilbao, Barcelona, Sagunto, Cartagena, Huelba

[229] Bloomberg, 2022, *Russia is Spains No. 2 gas supplier as Algerian flows drop*, 11 July. Available at: https://www.bloomberg.com/news/articles/2022-07-11/russia-becomes-spain-s-no-2-gas-supplier-as-algerian-flows-drop.

[230] Bilbao was the only almost all occupied (88%).

[231] Dworkin, A., 2022, *North African standoff: How the Western Sahara conflict is fuelling new tensions between Morocco and Algeria*. European Council on Foreign Relations, 8 April. Available at: https://ecfr.eu/publication/north-african-standoff-how-the-western-sahara-conflict-is-fuelling-new-tensions-between-morocco-and-algeria/.

and Italy (via the Transmed pipeline) are not being used at their full capacity suggests that pipeline deliveries from Algeria are being hindered by Sonatrach's increasing difficulties in the upstream[232], rather than a lack of export pipeline capacity.[233]

Limited connections to the rest of Europe

Many stakeholders interviewed considered the limited cross-border capacity between Spain and France as one of the key bottlenecks in the EU gas system at the moment. The countries are interconnected by two pipelines at Larrau and Biriatou (68 TWh/7bcm). From 2022, the flows were directed to France, yet less than 50% of pipeline capacity was used in the first half of 2022.

As mentioned above, the network expansion (the South Transit Eastern Pyrenees pipeline, STEP, project, and part of the larger MidCat project) had been stalled for years; in 2019, France decided to abandon the project as financially non-viable. As the current energy crisis worsened, the discussions on the MidCat project had been revived throughout 2022. One of the options discussed by several stakeholders interviewed could have been establishing flows via France to southern parts of Germany, which is lacking alternative supplies. However, following uneasy discussions on the MidCat pipeline[234], in October 2022, France, Spain and Portugal agreed to launch a completely new project, a 'green corridor', by building BarMar, a new pipeline between Barcelona to Marseille, which will be adapted to transport hydrogen and other renewable gases. With the potential to bring renewable gases to Central Europe and south Germany, this project may be not, however, a response to the current crisis and the current needs of Germany and Central Europe as the experts interviewed pointed out.

Arguably, the intensive discussions on the MidCat pipeline put solidarity among Member States to the test. As pointed out by some experts interviewed, the final cancellation of the MidCat pipeline could be viewed as a success for France. With several major LNG terminals, France is arguably in a strong position to bring LNG imports to Germany via the upgraded interconnector with Germany, as well as via Belgium. The MidCat pipeline had not been supported by France since the beginning though. Initially, the pipeline was designed to bring Algerian pipeline gas to Europe via Spain. Turning this initial project into the one aimed to bring LNG incurred additional costs of inter alia regasification and transportation, requiring major investments. Initially, the cost split between France and Spain was unbalanced – with most financial burden put on Spain.

With the new BarMar pipeline on the table, a fast unlocking of Spanish LNG capacity seems to be unfeasible. Further, discussions about an **offshore pipeline to Italy** to tap into regasification capacity on the eastern shores of Spain where three large LNG terminals are located were put on the agenda in Spring 2022. In May 2022, Snam and Enagas, Italian and Spanish TSOs, agreed to assess the technical feasibility of this offshore pipeline.[235] Although the details of a potential project are largely unknown, this project may be highly problematic considering the low social acceptability of large-scale gas

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[232] Euractiv, 2022, *Why can't Algeria solve Europe's gas woes?* 18 August. Available at: https://www.euractiv.com/section/energy/opinion/why-cant-algeria-solve-europes-gas-woes/.

[233] Fulwood M, Honoré, A., Sharples, J, 2022, *RePower EU and the Short-term Outlook for the European gas market*, Oxford Institute for Energy Studies. Available at: https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2022/07/REPowerEU-and-the-Short-Term-Outlook-for-the-European-Gas-Market-.pdf.

[234] Heller, F, 2022, *MidCat gas pipeline row between Spain, France intensifies*, Euractiv, 7 September. Available at: https://www.euractiv.com/section/energy-environment/news/midcat-gas-pipeline-row-between-spain-france-intensifies/.

[235] Reuters, 2022, *Snam signs deal to study Spain-Italy gas pipeline*. 12 May. Available at: https://www.reuters.com/business/energy/snam-signs-deal-with-enagas-study-spain-italy-gas-pipeline-2022-05-12/

projects in Italy. For years, Italy experienced problems in progressing with LNG projects; the TAP was extremely contested with strong opposition from the local communities in the region of Puglia[236].

With the low social acceptance of such projects, it might be extremely unlikely that Tuscany or Liguria would succeed in building the offshore pipeline between Italy and Spain. As well, an allegedly large estimated capacity (about 30 bcm), would require significant investments in times of high uncertainty about the future of natural gas in Europe.

Arguably, one of the options in the short term is **physical swaps** of pipeline imports from Algeria between Spain and Italy. Over the summer of 2022, Algeria increased supplies to Italy[237]. Spain has large-volume pipeline supply contracts with Algeria, as does Italy, and it is possible, either within the contract terms or by requesting some flexibility, that Algeria sends more pipeline gas to Italy and less to Spain, with Spain making up any shortfall by importing more LNG.

Alternatives to source Germany and Central Europe

Although much attention focused on the option to bring LNG from the Iberian Peninsula to Germany, consultations with stakeholders reveal that as a short-term priority, the expansion of capacity between Belgium, France and Germany remains the most important bottleneck. The difference in the standards for odorised gas applied by France and Germany limited in the past the volumes of French supplies in the German direction. Almost all flows from France to Germany need to transit via Belgium. Arguably, in the past, there was a limited need for gas supplies from France to Germany, as the latter met its demand with supplies from Norway and Russia, via Nord Stream 1 and Yamal Europe. In the current context, the first-rank solution would be linking and expanding connections between Belgium and Germany and France and Germany. Currently, only the Obergailbach interconnection point links France and Germany, operating predominately from Germany to France. Since October 2022, following necessary technical adjustments made by GRTgaz after consultation with stakeholders on the market, organised by the Commission de Régulation de l'Energie (France's Energy Regulatory Committee), reverse flows started from France to Germany[238].

As Germany relied on supplies from Russia for about 54% of its total gas demand, their replacement becomes a serious test. Five FSRUs are currently planned in Germany; also the expansion of Rotterdam and Zeebrugge terminals in upcoming years would allow Germany sourcing gas directly. The FSRU terminal in Eemshaven (Netherlands), commissioned already in September 2022, could also add to possible imports into Germany.

Moreover, with the German decision to commence its own LNG imports via five leased FSRUs, each of at least 5 bcm, prospective gas deliveries from Spain may further lose attractiveness. Wilhelmshaven FSRU[239], which is currently under construction, is expected to be commissioned by the end of 2022 and will become the first LNG hub in Germany. Another state-chartered FSRU is envisaged to arrive at Wilhelmshaven in winter 2023/24. Brunsbuettel FSRU should become operational by the end of 2022

[236] E.g. Reuters, 2018, *Italy PM Conte gives green light to contested TAP gas pipeline*. 26 October. Available at: https://www.reuters.com/article/us-italy-tap-pm-approval-idUSKCN1N02K0.

[237] France 24, 2022, *Italy signs clutch of deals with Algeria in bid to boost gas supply.* 18 July. Available at: https://www.france24.com/en/europe/20220718-gas-supplies-from-algeria-to-italy-to-increase-in-coming-years-says-draghi.

[238] GRTGaz, 2022, GRTgaz announces delivery of the first physical flows from France to Germany. Available at: https://www.grtgaz.com/en/medias/press-releases/grtgaz-announces-delivery-first-physical-flows-france-germany.

[239] LNGPrime, 2022, *Uniper: first German LNG import terminal to be ready this winter.* 4 July. Available at: https://lngprime.com/europe/uniper-first-german-lng-import-terminal-to-be-ready-this-winter/56140/.

or in early 2023; further expansion of the facility to an onshore LNG terminal is planned as well. The Hanseatic Energy Hub (HEH) is to receive an FSRU at Stade by the end of 2023.

Further, by 2026, there are also plans to expand the capacity to an onshore terminal merging the facilities in a land-based hub. The planned onshore LNG terminals in Brunsbuttel and Stade would improve the security of supply, but only in the mid-term.

The fifth FSRU leased by the German government is to be docked in Lubmin, where landfall facilities of Nord Stream 1 and 2 are located and are expected to be operational by the end of 2023.

4.3.2. The Baltic region: connecting the 'gas island' to Central Europe

The infrastructure developments in the Baltic region, i.e. Estonia, Finland, Latvia and Lithuania, have been rather a success story of breaking up a legacy of Gazprom's monopoly in the region. For a long time, the Baltic Sea region had the lowest diversity of supply sources in terms of the geographical origin of gas with Russia remaining a dominant or – as in the case of Finland – the only supplier of natural gas and had not been interconnected to the rest of the EU gas market. Finland had remained the only Member State to be fully supplied by a single gas source (Gazprom) until the Balticconnector pipeline between Estonia and Finland became operational in 2020. The lack of cross-border interconnection between Poland and Lithuania kept the region as a 'gas island' until May 2022, when the Gas Interconnector Poland-Lithuania (GIPL) finally connected these countries to the EU gas market.

Currently, with a firm commitment of the countries of the region to substitute all Russian pipeline imports, several additional infrastructure projects are needed, including an FSRU for Estonia and Finland, an expansion of Latvia–Estonia interconnector and – further in Poland – a new LNG terminal in Gdansk. However, with a growing competition of Member States over several new LNG terminals far exceeding the region's needs, there might be a suboptimal outcome of regional gas infrastructure.

Existing gas infrastructure

Until recent months, Estonia and Latvia received most imports from Russia via cross-border interconnectors; Lithuania also received Russian gas via Belarus.[240] Connected to Estonia and Lithuania, Latvia serves as a regional security hub with the Inčukalns UGS (24 TWh/4.5 bcm) near Riga. Since Estonia, Finland and Latvia are part of the same entry-exit zone[241] created in 2020, companies can book their capacity in the Latvian UGS ensuring supplies to their countries.

For a long time, the region remained substantially affected by a lack of connection to the rest of the EU gas market. The situation has been improved with several infrastructure projects completed as part of the diversification policies. Lithuanian **Klaipeda LNG** (approx. 40 TWh), an FSRU named 'Independence', became operational in late 2014 and marked a step toward the country and region's more diversified gas portfolios. Although its utilisation rate was initially low (only 20% in 2018)[242], after the release of long-term booked capacity in 2019 it increased. Commissioning an FSRU allowed Lithuania to significantly improve their portfolio. In 2021, the country's gas imports portfolio comprised

[240] Elering, 2018, *Estonian Gas Transmission Development Plan 2018-2017*. March. Available at: https://elering.ee/sites/default/files/attachments/Estonian_gas_transmission_network_development_plan_2018_2027.pdf.

[241] Roadmap on regional gas market integration between Estonia, Finland, Latvia and Lithuania, 20 April 2020. Available at: https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/news/documents/roadmap_on_regional_gas_market_integration.pdf.

[242] ACER and CEER, 2019 *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2018. Gas Wholesale Markets Volume*. October. Here p. 23.

supplies from Norway, which reached over 50%, Russian imports dropped up to a quarter, and US LNG cargoes gradually increased[243].

As a project of regional importance, Klaipeda LNG also serves to supply non-Russian gas to adjacent markets.

Among others, LNG imports are directed to Latvia, where they can access the Latvian UGS and further be consumed in Latvia or shipped to Estonia and further to Finland via the Balticconnector, which was completed in 2020. For example, in recent months, Eesti Gas purchased 2TWh to be delivered via Klaipeda LNG later this year, after Estonia decided to halt all Gazprom pipeline imports[244].

The **Balticconnector** pipeline finally linked Finland to the newly formed Latvian-Estonian gas market areas in 2020. As an important element of the common entry-exit zone of Estonia, Finland and Latvia, current shipping is made mostly in the direction of Finland, with marginal volumes sent from Finland. Finland has also a pipeline connection with Russia via Imatra, which is not operational since May 2022, when Gazprom's supplies were cut off. In Finland, there is also a small Manga LNG terminal in Tornio[245] but is used mostly for off-grid LNG supplies located nearby a large chemical producer.

The completion of the **Gas Interconnector Poland Lithuania (GIPL)** in 2022 finally connected Lithuania and other Baltic markets with Poland. The pipeline has 27 TWh of capacity in the direction from Poland to Lithuania and 21 TWh from Lithuania to Poland[246]. Because of piped gas interruption from Russia to Poland, the GIPL has only been used for Lithuania-Poland flows from Klaipeda LNG. Before the completion of the **LNG terminal in Swinoujscie** (58 TWh) in 2016, Poland predominantly received gas only from Gazprom via the Yamal Europe pipeline. With the **Baltic Pipe** commissioned in October 2022, supplies from Norway will become available in addition to LNG imports.

Changing supply patterns and physical flows

In 2021, Finland decreased the share of Russian imports to about 75% increasingly sourcing volumes via the Balticconnector. Since the cuts of Gazprom's supplies to Finland in April 2022, the Balticonnector is used to ship gas from Latvian UGS to Finland. As the Balticonnector is bi-directional, opposite flows from Finland to Estonia are also technically feasible; however, that direction has been rarely used as currently there are no flows from Russia to Finland. As Finland has no storage facilities and pipeline supplies from Russia are currently interrupted, Finland increasingly becoming dependent on uninterrupted flows via Estonia.

With the commissioning of GIPL in May 2022, flows have also increased from Lithuania to Poland, sourced via Klaipeda LNG. Flows from Latvia to Lithuania are on the decline in 2022; contrarily LNG sourced via Klaipeda LNG is on the rise directed to Latvia and Estonia. US LNG supplies to the Baltics increased. Commissioning of the **Baltic Pipe** in September 2022 will further increase flows in these directions. The newly completed Interconnector Poland-Slovakia will further tie the markets of Central Europe to pipeline supplies from Norway and LNG imports.

243 ACER and CEER, 2022, *Annual report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Gas Wholesale Markets Volume*.

244 ERR.ee, *Eesti Gaas buys €300 million worth of Norwegian LNG for coming Winter.* 12 July. Available at: https://news.err.ee/1608654946/eesti-gaas-buys-300-million-worth-of-norwegian-lng-for-coming-winter.

245 Gasum, n.d., *LNG terminal in Tornio.* Available at: https://www.gasum.com/en/our-operations/lng-supply-chain/terminals--liquefaction-plants/manga-terminal-tornio/.

246 AmberGrid, n.d. Gas interconnection Poland-Lithuania. Available at:, https://www.ambergrid.lt/en/projects/gas-interconnection-poland-lithuania-gipl#:~:text=The%20GIPL%20link%20will%20have,direction%20of%20Poland%20per%20year.

Planned and ongoing infrastructure projects

In terms of cross-border infrastructure, Annex 3 of the RepowerEU plan outlines a need for an **FSRU in Finland/Estonia** and **Gdansk LNG terminal in Poland** (by 2025/26), which is already included in the 5th PCI list.

An FSRU is expected to meet demand in Estonia and Finland and replace Russian pipeline imports. Gdansk LNG will further add capacities in Poland and potentially can bring gas down to Central Europe through the recently completed Poland-Slovakia interconnector, and possibly, to Ukraine.

However, it might be noted that there are few signs of coordinated actions on the expansion of LNG capacity in the region, also within the Baltic Regional Gas Market Coordination Group[247], a regional task force aimed at coordinating Member States' efforts in the region, as pointed out by stakeholders interviewed. In June 2022, Gasgrid Finland, a state-owned company and transmission system operator, jointly with Fortum announced Finland's first FSRU at the port of Inkoo, in southern Finland. Located close to the Balticconnector, an FSRU (40 TWh) will be jointly leased with Estonia and cover the gas demand in both countries. Leased from Excelerate Energy Inc. for ten years, the FSRU is expected to be commissioned by the end of 2022. Competition allegedly existed between Estonia and Finland on whether the FSRU would be docked at Inkoo in Finland or Paldiski in Estonia. The decision announced in mid-October 2022 reveals that the FSRU will be moored in Finland[248].

Although this joint Estonian-Finnish terminal can supply more than the annual demand of both countries[249], and Klaipeda LNG has capacities to supply also the Latvian market, Latvia also announced plans to dock a new FSRU in Skulte and connect regasification units to the grid and further to the Inčukalns UGS[250]. In case both FSRUs, a Finnish-Estonian and a Latvian one, are commissioned, overcapacity will occur in the region with unclear dynamics of costs. As the Latvian FSRU is to be located next to the UGS, it can be more economically rational. However, Estonia and Finland advance at faster rates and the FSRU will be commissioned in the upcoming months.

With **small-scale LNG demand** growing in the Baltic region, among smaller projects, the Hamina LNG terminal (onshore) is a joint venture between Finnish company Hamina Energy, technology group Wärtsilä, and Estonian energy company Alexela. With modest capacity with pipeline access of 3 TWh and off-grid uploading of 3 TWh, it would also offer truck loading services from two bays and bunkering services.

4.3.3. South-East Europe and Italy

Diversification of gas supplies in South-East Europe reveals that regulatory and political issues have contributed to the persistence of the infrastructure's inadequacy in the region and increased the transaction costs for completing new infrastructure. Although additions of new infrastructure experienced significant hurdles over the last decades, also persisting regulatory bottlenecks prevent efficient use of the existing capacity.

[247] https://www.acer.europa.eu/gas/network-codes/gas-regional-initiatives/baltic-regional-gas-market-coordination-group.

[248] Argus, 2022, *Estonian priority access to Finnish FSRU unsure*. 14 October. Available at: https://www.argusmedia.com/en/news/2380621-estonian-priority-access-to-finnish-fsru-unsure.

[249] 40 TWh of capacity vs 30 TWh of the Estonia-Finland annual demand. The Estonian gas demand is small (4.1 TWh) and is currently declining at expense of national oil shale production.

[250] Latvian Public Broadcasting 25 July 2022, *Building two LNG terminals in Latvia is a possibility, says Economics Minister*. Available at: https://eng.lsm.lv/article/economy/economy/building-two-lng-terminals-in-latvia-is-a-possibility-says-economics-minister.a466710/.

Infrastructure in South-East Europe

South-East Europe, except Romania with notable domestic gas production, historically depended on Russia and relied on imports via the Transbalkan pipeline. The Revithoussa LNG in Greece remained the only option to source an alternative supply. However, the situation slowly changed in recent years. With the opening of the Southern gas corridor in 2020, Caspian gas from Azerbaijan was brought to the region via the Trans Adriatic Pipeline (TAP) of 10 bcm supplying Greece, Albania and further Italy.

Along gradual expansion of LNG capacities in the region, Krk LNG in Croatia started operations in 2021. Subsequently, flows from Croatia to Hungary increased significantly compared to 2021, whereas before flows were mostly from Hungary sourcing Russian gas to the rest of South-East Europe, but few flows between Croatia and Slovenia have occurred since the beginning of 2022.

To unlock supplies from the TAP to Bulgaria, the Interconnector Greece-Bulgaria (IGB) had been essential but persistently delayed and was finally commissioned in October 2022. The IGB will allow physical supplies from the TAP to Bulgaria. Until now, Bulgaria's only access to non-Russian pipeline gas supply has been via swap deals with Greece, given that Greece receives its Russian gas via Bulgaria. Physically, Bulgaria receives Russian gas and Greece receives Azeri gas, but on paper, swaps mean that Greece still gets its Russian supplies but Bulgaria gets access to Azeri supplies[251].

SEEGAS Report on regional transmission routes, recently published by the Energy Community Secretariat[252]. shows that although some interconnectors need to be upgraded or built, the key issue in the region is not a lack of physical infrastructure but its heavily under-utilisation and persisting regulatory barriers. This is also confirmed by several interviews with experts on the region. Among many others, lack of interconnection agreements between many countries and weak institutions and lack of regulatory certainty and politicisation of regulators have been named.

In terms of the bottlenecks, some notable issues lie at the Romania-Bulgaria border where only one line out of four lines of the TransBalkan pipeline is used, at the border between Bulgaria and North Macedonia, where Gazprom books full capacity and no interconnection agreement is signed. Similarly, discussions on an interconnection agreement at the border between Bulgaria and Turkey have been on hold for years. Although some additional capacity is needed, for example, between Hungary and Croatia or expansion of reverse flows between Hungary and Austria, regulatory issues remain the key problem in the region.

Diversification of supplies in Italy

With increasing needs to bring additional gas volumes to the European markets, some discussions emerge on the prospects of Italy becoming a gas hub tying the supplies from inter alia the Iberian Peninsula, North Africa and the Southern gas corridor, as well as LNG imports, with Central Europe. This vision, however, should be taken with a grain of salt considering uncertainties about the future of gas demand and the feasibility of large-scale investments into additional gas infrastructure. Notably, low social acceptance of large-scale infrastructure projects in the country, discussed in section 4.3.1 is also to be taken into account.

Interconnection between **Italy and South-East Europe** gained relevance in light of the Southern gas corridor. However, the first stage of the TAP was increasingly contested by the local population and

[251] Bulgarian News Agency, 2022, *Bulgargaz requests swap transaction for September 2022*. Available at: https://www.bta.bg/en/news/economy/311244-bulgargaz-requests-swap-transaction-for-september-2022.

[252] Energy Community Secretariat, 2022, *SEEGAS Report. Regional transmission routes*. Available at: https://www.energy-community.org/regionalinitiatives/SEEGAS.html.

regional authorities. As discussed with the stakeholders interviewed, contrary to the experience, the regional authorities and the national government are now more in favour of doubling the capacity of the TAP (the extension estimated up to 10 bcm) as only limited intervention into the local port infrastructure will be required.

However, an increase in the TAP capacity can be feasible not earlier than the end of the 2020s. Although the discussion of the expansion of the TAP is at its early stage[253], it may be still more politically feasible compared to an offshore pipeline between Spain and Italy (see section 4.3.1).

The **EastMed pipeline** of an initial 10 bcm is projected to bring natural gas from offshore fields in the Eastern Mediterranean to Greece or/and Italy via Cyprus and Crete. A variety of opinions exists regarding the feasibility of the pipeline and its tentative timeline. Although new fields provide tangible reserves to tap into, a sensitive political situation in the region, including complexities of the relations between Turkey, Egypt, Israel, Greece and Cyprus, implies higher security risks for the investors.

Concerning pipeline supplies from **Algeria**, the previous Italian government used an opportunity to source additional volumes redirected from Spain during the summer of 2022. With a growing share of Algerian imports in the Italian gas portfolio after the agreement to source an additional 4 bcm sealed in July 2022, Algeria has regained the status of Italy's biggest gas supplier – a position previously held by Russia[254]. At the same time, the Algerian gas sector has been experiencing upstream problems for a long time. So far, piped imports operated under-capacity: the Trans-Mediterranean pipeline connecting with Algeria was slightly above 50% in January-August 2022. To increase diversifying options, ENI strengthens its presence in Algeria by acquiring BP's upstream business in the country in September 2022[255].

With the growing role of **LNG**, new opportunities are considered to expand the capacities of LNG terminals. In the mid-term, reverse flows to Austria can be expanded to ship gas to Austria and Central Europe. Currently, there are three terminals in Italy (see section 4.2); two relatively small, i.e. Panigaglia and Livorno, and the large one, Adriatic LNG. The Adriatic LNG is contracted by Qatar Petroleum on a long-term basis which creates contractual limitations for re-export. The new unit is expected to be completed in 2023-24; as located in North Italy where natural gas is predominately consumed, costs of gas are expected to be lower excluding transportation costs of gas imported into South Italy. Another project – an FSRU of 5 bcm to be anchored in the port of Piombino in Tuscany – faces strong opposition from the local communities and the city council, although it has received approval by a state-appointed commissioner and is expected to be commissioned in Q1-2 2023[256].

4.4. Phase out of Russian gas imports: an infrastructure side

This chapter has assessed the gas infrastructure in the EU to analyse the physical capacities and regulatory readiness to replace the gas flows from Russia. This section will provide a summary in the form of a short SWOT analysis and will make preliminary evaluations of the physical capacities to replace Russia gas supplies. Based on the assessment of the various relevant elements of the gas

[253] Euractiv, 2022, *Azeri president says investors discussing expansion of TAP gas link*. 2 September. Available at: https://www.euractiv.com/section/energy/news/azeri-president-says-investors-discussing-expansion-of-tap-gas-link/.

[254] Euronews, 2022, *Algeria becomes Italy's biggest gas supplier in new €4bn deal to reduce Russian dependency*. 18 July. Available at: https://www.euronews.com/2022/07/18/italys-draghi-visits-algeria-for-gas-talks-while-political-crisis-continues-at-home.

[255] Offshore Technology, 2022, *Eni to buy Algerian upstream business of BP*. 8 September. Available at: https://www.offshore-technology.com/news/eni-algerian-upstream-bp/.

[256] Offshore Technology, 2022, *New LNG terminal in Italian port of Piombino receives approval*. 26 October. Available at: https://www.offshore-technology.com/news/lng-terminal-italian-greenlight/.

infrastructure in the previous sections, Table 4.5 summarises the key strengths and weaknesses of the EU gas infrastructure, and opportunities and threats for sourcing gas supplies alternative to Russian pipeline imports.

Table 4.7: SWOT analysis of the EU gas infrastructure

Strengths	Weaknesses
• A high level of interconnection has been achieved since 2010 • Functioning reverse flows have been implemented at most cross-border interconnection points across the EU • New interconnectors have been commissioned, particularly in Central and South-East Europe and the Baltics • Substantial LNG capacity has been commissioned in North-West Europe and the Iberian Peninsula; since the 2010s, an increasing number of LNG terminals, both onshore and FSRUs, have become operational in Central and South-East Europe • New onshore terminals/FSRUs are being streamlined by Member States to diversify away from Russian gas imports • New regulation on underground gas storage was adopted to provide regulatory clarity for SSOs and filling targets • REPowerEU provided clear targets and plans for additional gas infrastructure and tools for joint gas purchasing, e.g. via the Energy Platform, to reduce dependence on Russia	• Uncertainty persists regarding the future of natural gas, particularly in the medium term (by 2030) creating a vacuum for investment decisions • Regional competition for LNG terminals and FSRUs particularly poses risks of gas overcapacity in light of the estimated decrease in gas demand • Remaining infrastructure bottlenecks across the EU and consistent delays of PCIs may pose challenges for a fast phase-out of Russian gas both from the infrastructural and regulatory sides • Contractual congestion persists, even when there is enough physical capacity, especially in South-East Europe • Regulatory patchwork for LNG terminals' operation may be addressed to increase interoperability within the EU • Trade-offs persist between high utilisation of LNG capacity via long-term capacity booking and flexibility needed for shorter-term LNG deliveries • Low acceptance of and social resistance towards new gas infrastructure, especially LNG terminals, in some Member States, which reflects the EU decarbonisation commitments, but prevents a timely diversification away from Russian imports • Few bilateral solidarity agreements between Member States concluded in case of emergencies
Opportunities	**Threats**
• Elevated gas prices stimulate alternatives, facilitating a boost of renewable energy deployment and increasing emphasis on energy efficiency measures • Sourcing incremental supplies can be facilitated by a joint gas purchasing mechanism through the Energy Platform by pooling demand, especially of Central and South-East European Member States. Diplomatic outreach to not only exporters but also other importers could result in new frameworks and agreements	• Volatility and uncertainty of the global gas market will remain to create the price cycles reflected also in the European gas market • Persisting high prices create unfavourable conditions for entering now into long-term contracts for LNG supplies • Tight global supply in the next couple of years may be expected to pose a risk in sourcing additional volumes • The availability of FSRU facilities on the market may create a bottleneck for leasing additional FSRUs

• Despite the tight global gas market and varying estimations, new supply is expected to come online in upcoming years • In terms of physical capacity, the LNG market in the EU remains attractive as a regulated 'last resort' market	• Increasing supplies from autocratic regimes may create alternative dependencies and risks

Source: authors' own elaboration.

In March 2022, the European Commission, in its Communication *REPowerEU: Joint European Action for more affordable, secure and sustainable energy*, stipulated an ambitious goal to reduce Russian gas imports by **two-thirds, or roughly by 100 bcm by the end of 2022** compared to 155 bcm of imported Russian piped and LNG gas in 2021.

As discussed in section 4.1, the Communication foresees various measures, which can be approximately grouped into the procurement of non-Russian gas and gas demand reduction. Thus, it foresees[257]:

- **Diversification of gas supplies by 63.5 bcm**, including (i) an increase of LNG imports by 50 bcm; (ii) an increase of pipeline imports by 10 bcm; and an increase in bio-methane production by 3.5 bcm; and
- **Gas demand reduction of 38 bcm**, including (i) EU-wide energy savings and energy efficiency measures by 14 bcm; (ii) solar rooftops of 2.5 bcm, (iii) heat pump roll-out by 1.5 bcm; (iv) reducing demand in the power sector by 20 bcm.

Table 4.6 provides a summary of these envisaged measures and the preliminary estimations for the actual diversification and gas demand reduction during January-October 2022. As official data are yet to be published, these estimations rely upon the assessment recently published by the IEA[258] and several other reports and should be viewed as a "rule of thumb" assessment rather than a detailed methodologically sound calculation. Statistics for 2022 will provide data for more detailed assessments.

[257] Fulwood, M et al., 2022, *The EU plan to reduce Russian gas imports by two-thirds by the end of 2022: Practical realities and implications*.

[258] IEA, 2022, November, *Never too early to prepare for next winter: Europe's gas balance for 2023-2024*.

Table 4.8: Dynamics of replacing Russian pipeline imports by two-third by the end of 2022, January-October 2022

Russian supplies in 2021	Demand reduction estimates for 2022	Diversification of gas supplies estimates
155 bcm (piped gas and LNG); **145 bcm** (piped gas only)	Reducing **38 bcm total**	Increase of **50 bcm of LNG** and **10 bcm of pipeline imports** + biomethane production of 3.5 bcm
Russian supplies (Jan-Oct 2022)	**Demand reduction (Jan-Oct 2022)**	**Diversification (Jan-Oct 2022)**
According to the IEA, Russian pipeline supplies dropped by 60 bcm in Jan-Oct 2022, and a further drop by **80 bcm** in total is expected by the end of 2022. To note, Russian supplies were close to 'normal' levels during the first half of 2022; sharper decreases may be expected for the second half of 2022. Than would mean Russia would deliver about **60 bcm of piped gas in 2022.**	EU demand reduced roughly by 10% in Jan-Oct 2022 comprising about **40 bcm**. This has resulted in a combination of measures, including lowered energy consumption across sectors, "some efficiency gains and behavioural responses to high gas and electricity prices" (IEA 2022). Demand destruction, particularly in energy-intensive industries, is to be accounted too.	Supplies from Norway grew by +5% (**5 bcm**); Azeri supplies via the TAP increased by +50% (**3 bcm**) as the pipeline became fully operational. Both these sources run close to their nameplate capacity Algeria increased pipeline supplies by +10% (**3 bcm**). An increase in LNG imports **(+42 bcm**) was delivered via reconfiguration of global supply flows due to the EU's high demand for LNG (+23 bcm) and LNG imports fall in China (by 20% YoY) and other regions, which consequently released additional LNG volumes sourced by the EU (+19 bcm).

Source: Authors' own elaboration based on IEA, 2022, November, *Never too early to prepare for next winter: Europe's gas balance for 2023-2024*.

A domino effect of gas supply cuts and reductions by Gazprom via Yamal Europe, the Ukrainian gas transmission system and Nord Stream 1 already reduced pipeline imports from Russia to 49.6 bcm in the first half of 2022. As a rule of thumb, that is about 20 bcm less than in the same period in 2021 (approx. 70 bcm) and 40 bcm less than in 2020 (92 bcm)[259]. The IEA provided in its recent analysis that the reduction of Russian imports reached 60 bcm in January-October 2022 compared to the same period in 2021 and will likely not be more than 60 bcm in total by the end of 2022.

To compensate for falling pipeline imports from Russia, US LNG inflows accounted for a record 36.8 bcm in the first half of 2022 (compared to 26 bcm in 2021) and were sustained by stable imports from Qatar, Algeria and other LNG exporters. Gradual reductions of Russian imports when Russian imports were closer to their usual capacity in the first half of 2022 and record US LNG cargoes allowed filling in

[259] ACER, 2022, *EU and UK gas supply portfolio 2015_2021 bcm_year*. Available at: https://aegis.acer.europa.eu/chest/dataitems/210/view.

the UGS at above 90% average by the beginning of the heating season 2022. Although a high level of uncertainty and price volatility during 2022 raises questions concerning the structural nature of high gas prices following the replacement of Russian gas, prices were driven down since late August 2022, largely motivated by mild weather, UGS filled above 95% by November 2022, and large LNG inflows into Europe. By the end of October, TTF month-ahead prices decreased to around 100-120 MWh.

As these preliminary assessments by IEA (2022) show, the gas market dynamics during the first ten months of 2022 look closer to the estimations made in the RepowerEU. However, it might be worth considering whether this reduction in gas imports would be sustainable in the near years. First, a big uncertainty refers to whether Russia will continue to supply about 60 bcm in 2022. Should the Russian Government decide to shutdown the flows completely; the EU will need to source about 100 bcm annually additionally to the level of 2021. Second, global LNG capacity needs to increase to match the further reductions of Russian deliveries. IEA (2022) estimates only 20 bcm of new LNG supply come online in 2023; with a potential increase of demand in among others China, the LNG market may turn to be tighter, again raising the issue of procurement of these additional flows.

In case only the routes via Ukraine and Turk Stream remain operational to deliver Russian supplies since 2023, filling in UGS for the next winter season of 2023-24 will become an increasingly contested issue. As several experts interviewed pointed out, the winter season of 2023-24 may be the most difficult, and only after its passage, the gradual stabilisation of European gas markets may occur. This is confirmed by the study recently prepared by Rystad Energy[260] with the support of the International Association of Oil and Gas Producers and the American Petroleum Institute. Should flows via Ukraine and Turk Stream cease in 2023, no Russian supplies will create a 'supply gap' during 2023-2025, which will have to be filled by spot LNG cargoes. Domestic production will be unable to close this gap as the Groningen field has been capped this year, and Norway is operating at almost its maximum capacity. No other options seem to be available to replace completely the imports of Russian gas. Gradually, spot LNG will cover some part of Russian supplies during the next several years and then will be gradually replaced with longer-term contractual commitments. In the medium-term, from 2027, long-term contracts for LNG and the completion of the relevant infrastructure projects will ensure alternatives to Russian pipeline imports and will rebalance the EU market.

In the medium term, the phase-out of Russian supplies will vary across Member States and regions.

In North-West Europe (Belgium, Netherlands, France), where imports from Russia played a marginal role not exceeding 8% in the final energy consumption and are balanced with Norway and LNG in various proportions, the phase-out can be relatively easy. The Iberian Peninsula has plenty of LNG capacity and will remain self-sufficient as well. Although Spain imports sufficient volumes of LNG from Russia, the structure of the global LNG market prevents exporters from excessive manipulations. However, the region will continue to remain a bottleneck for upcoming years, and no supplies will be released further to the continent.

In the Baltics, the recent completion of several interconnectors and the installation of the FSRU in Finland by the end of 2022 will satisfy the demand of both Estonia and Finland. Latvia and Lithuania will have access to supplies from Klaipeda LNG. Also for Poland, with the commissioning of the Baltic Pipe, additional volumes could be sourced from Norway to supplement LNG deliveries at Świnoujście LNG. With the infrastructure in place, however, the question would be the availability of

[260] Rystad Energy, 2022, *Rebalancing Europe's Gas supply. Opportunities in a new era*. Available at: https://iogpeurope.org/project/rebalancing-europes-gas-supply-opportunities-in-a-new-era/.

physical supplies on the market to be delivered, as well as the decisions of market participants to enter into long-term contracts at times of elevated prices and gas demand destruction.

For Italy, securing additional volumes from Algeria would smoothen the potential cuts or reductions of Russian supplies. An expansion of the Adriatic LNG would add to the security of supply for the medium term. The TAP can be expanded by 2027-2030 but the volumes are estimated not to exceed 10 bcm.

Germany would remain the biggest bottleneck as it needs to reconsider urgently its dependence on pipeline supplies from Russia. FSRUs that will be commissioned in these years will provide certain relief but the key bottleneck will emerge should the Russian pipeline imports not resume.

5. CONCLUSIONS AND POLICY RECOMMENDATIONS

In this final chapter, we summarise the main conclusions drawn from our research and present a list of policy recommendations for the considerations of the European Parliament.

5.1. Conclusions

The EU has been heavily dependent on natural gas as one of the main energy carriers in the EU making up over 23% of its energy mix in 2020. With low and decreasing domestic production of natural gas, much of this demand is satisfied through imports with the EU's import dependency averaging 84% in 2021. While EU Member States aim to phase out natural gas, National Energy and Climate Plans foresee its continued use as a transitional energy carrier providing flexibility in their 2030 national targets with the ambition of phasing out natural gas by 2050.

This decarbonisation pathway has led to the gradual decline of fossil fuel investments. However, recently it has come under pressure from the Russian invasion of Ukraine, which suddenly required EU Member States to implement the phase-out of natural gas in the medium- to long-term while diversifying supply away from Russian imports and investing in new natural gas infrastructure in the short-term. The EU suddenly finds itself between the policy goals of ensuring the security of supply and price affordability, while accelerating the decarbonisation of the gas sector.

The proposed revision of the Third Energy Package for Gas, the 'EU Hydrogen and Decarbonised Gas Market Package' provides a framework to enable renewable and low-carbon gases to enter the market and thereby work towards decarbonisation, security of supply and resilience against gas market price volatility. This package, which was introduced before the war in Ukraine, had received support in terms of its overall goals and ambitions, but also criticism for its somewhat strict approach to a hydrogen market that is yet to develop.

The introduction of hydrogen presents an opportunity for decarbonisation and autonomy, but it is not the objective in itself. Neither is it a silver bullet since replacing natural gas will take time and effort, while the production of renewable hydrogen will require vast amounts of renewable electricity, which will also be needed for decarbonisation in other sectors.

5.1.1. The role of unbundling rules and regulation in the gas and hydrogen market

A key question being discussed by stakeholders and the European institutions is the **role of unbundling rules**. Unbundling requirements have been introduced to ensure that market actors performing competitive activities are restrained in their ability to also perform monopolistic activities creating thereby a regulated monopoly in the gas market. The European Commission has since the Second Energy Package made clear that ownership unbundling is the base option, but has provided for flexibility by allowing for other modes of unbundling. This enabled emerging gas markets to develop and the Member States to adapt to their situations. The Third Energy Package further reinforced unbundling and separation of gas supply and generation from the operation of transmission and distribution networks.

Due to the flexibility granted to Member States in implementing the rules, **unbundling rules have been implemented differently across the Member States**. While increasingly TSOs in Member States have moved to the strictest form of ownership unbundling, other forms of unbundling such as ISO and ITO models prevail among many TSOs. As of 1 January 2020 25 Member States had implemented the OU model. In addition, ten Member States had implemented also the ITO framework and two Member States the ISO framework.

The landscape for DSOs is even more heterogenous as requirements are less strict than for TSOs. There are over 1,300 DSOs with many serving smaller customer bases while for TSOs most Member States have only one TSO with a few exceptions: Austria (2), Belgium (2), France (2), Germany (12), Italy (3) and the Netherlands (3). Overall, the **EU was successful in creating a single competitive gas market**. In particular **unbundling rules have been vital in creating open and fair retail markets** with their benefits believed to outweigh administrative costs.

The challenges for the development of a hydrogen infrastructure similar to the current natural gas network are manifold starting from the main issue that the market is only emerging and is currently driven more by policy objectives than market demand. A first step was made with the proposal of the 'Hydrogen and decarbonised gas market package'. With its proposal, the European Commission aims to move the market more towards ownership unbundling, excluding, in particular, the ITO model from 2030 onwards. The Commission proposes as target rules the newer models of unbundling, which are ownership unbundling and the ISO model. However, network operators, especially from countries applying the ITO model, advocate against the increased strictness of unbundling. They argue that the current unbundling models for energy infrastructure have served the EU well and should therefore also be applied to the emerging hydrogen market. **We found insufficient evidence that the separate treatment of natural gas and hydrogen results in clear benefits**. At the same time, the Commission's proposals for excluding the ITO model combined with the legal separation between gas and hydrogen network operators would create additional costs and might discourage notably **(natural gas) network operators using the ITO model from making the necessary investments in hydrogen infrastructure**.

Despite its strict requirements, the European Commission proposal does **provide regulatory certainty with a clear timeline following a phased approach**, which will allow private actors to plan their investments into hydrogen infrastructure accordingly. It is unclear however if, apart from in a few Member States (France, Germany, Belgium and the Netherlands), a mature hydrogen market will have developed by the cut-off date (31 December 2030). Nevertheless, a common date for the entire EU will help avoid cross-border issues, which will be relevant as it is expected that hydrogen will need to be transported across borders. Moreover, the date sets clear ambitions for the uptake of hydrogen, which have recently been reinforced by the targets outlined in the REPowerEU plan.

Beyond the unbundling rules, there are also a few other regulatory issues in the gas market:

- **Funding for natural gas infrastructure**: Changes in the direction of gas flows due to the geopolitical situation have unveiled the need for new investments into natural gas infrastructure, while support from the EIB and TEN-E for fossil fuel projects such as natural gas has stopped. To address this conflict, exceptions have been put in place: TEN-E allows for support of transitional infrastructure projects that can be used before 2030 for natural gas before being repurposed; the EU Taxonomy classifies investments in natural gas as sustainable if they are seen as supporting the transition such as moving away from coal power; and many NRRPs include investments in gas infrastructure with the notion of making these ready for hydrogen and low-carbon gases;
- **Definition of renewable gas and hydrogen**: The current regulatory framework does not define renewable and low-carbon hydrogen, which creates a legal uncertainty that can be a barrier to investments. The proposed hydrogen and decarbonised gas market package put forward a definition in line with the proposal to amend the Renewable Energies Directive II (RED II) to allow certification of renewable and low-carbon hydrogen.

However, a Delegated Act outlining additionality requirements[261] was rejected by the European Parliament in an Amendment to the RED II instead proposing a simpler framework allowing Member States to regulate. Proponents of hydrogen argue that this will reduce red tape and speed up the deployment of hydrogen, while other stakeholders voiced concerns about it endangering decarbonisation efforts in other sectors that rely on renewable energy and could lead to increased electricity prices for consumers as well as create uncertainty by jeopardising a robust legal definition for renewable hydrogen making such a project less bankable;

- **Network planning**: Having separate overviews for different infrastructure types (hydrogen, natural gas, electricity) provides benefits through additional transparency and clear accountability, however, it should also be ensured that network plans are aligned and integrated where possible; and
- **Repurposing of infrastructure, planning and permitting:** With repurposing of infrastructure likely being one of the ways to create a hydrogen network it is important to have a clear regulatory framework and oversight when repurposing. There are currently some uncertainties and a deep understanding of both infrastructures is required as it would require knowledge about the value of assets when transferring them to new operators and anticipating demand to avoid ending up with underused assets. Regulation to facilitate the repurposing of existing gas networks is crucial, as well as the simplification of the planning and permitting procedures.

5.1.2. The uptake of hydrogen infrastructure

In the long term, the ambition of EU policymakers is to have hydrogen and in particular renewable hydrogen replace natural gas and allow the hard-to-abate sectors to decarbonise. The 'Hydrogen and decarbonised gas market package' is an important step in this regard as it addresses many of the shortcomings of the Third Energy Package for Gas and caters to the decarbonisation of gas through the introduction of new energy carriers such as hydrogen. Importantly, it also aims to address barriers such as the lack of a cross-border hydrogen infrastructure by providing rules for network tariffs, planning hydrogen infrastructure and establishing with ENNOH a dedicated entity for hydrogen network operators. However, currently, network operators do not operate hydrogen networks as these are mainly localised in industrial clusters and operated by private entities, where initial demand for hydrogen has developed.

Widespread deployment of a hydrogen network will require a **combination of constructing new infrastructure, repurposing existing gas infrastructure and blending at interconnection points**. This is for example foreseen by the EHB initiatives, which are endorsed by several TSOs and provide an ambitious scenario for a future EU hydrogen network. However, this scenario is not based on a thorough network planning exercise but shows what is possible based on cost assessments of operators. Findings from research showcase also that **repurposing existing gas networks is estimated to be the most cost-efficient option**. It would also support current network operators in avoiding ending up with stranded assets. However, it also requires the gradual replacement of natural gas raising difficult questions for each asset to find a timing to repurpose that would cause the least

[261] Additionality requires that renewable electricity used in electrolysers for the production of renewable hydrogen is additional to the renewable electricity which is used to meet the renewable penetration target with respect to final electricity consumption. This means producers of renewable hydrogen would need to ensure to use 'new' RES.

disturbance to existing natural gas markets while also not delaying the transition to hydrogen unnecessarily.

A future hydrogen network will also be smaller than the current natural gas network since ideally natural gas should be replaced by electrification and other means while hydrogen should be introduced in areas where otherwise decarbonisation would not be possible or too costly. Finally, to support the introduction of hydrogen by creating initial demand, especially in areas that lack dedicated hydrogen infrastructure, blending hydrogen in gas pipelines can be used as a transitional measure. Though this raises questions about the allowed purity levels as requirements differ between industries and Member States. Common **standards for blending at interconnectors will be beneficial as they will ensure continued cross-border gas flows**.

Hydrogen projects, both for production and infrastructure, will require large amounts of funding as the uncertainties about demand levels make private investments risky. Already, **IPCEI** such as the IPCEI Hy2Tech and Hy2Use and **the possibility to use PCI funds under TEN-E** provide additional funding opportunities from Member States and the EU to develop hydrogen projects. In addition, some Member States are making use of the funds under the NRRPs to support hydrogen projects. Finally, guarantees for hydrogen producers are to be provided through the newly proposed European Hydrogen Bank. Nevertheless, public funding alone will not be sufficient to support the development of a hydrogen network.

To support the uptake of hydrogen infrastructure, **revenues from user tariffs can be used, but will either put too large of a burden on the initial users or be insufficient during the first years**. Therefore, likely a combination of **cost mutualisation and subsidies will be needed to sufficiently decrease the burden on the first hydrogen users**. The proposed revision of the Gas Regulation introduces limited financial transfers between gas and hydrogen sectors to finance hydrogen networks. The risk is that this would increase gas prices and lead to households paying for the decarbonisation of industry, which is why the Commission limits its use in the proposed package.

Besides financing for infrastructure, several other barriers to hydrogen deployment were identified, these include the **duration and costs linked to permitting procedures for projects**. The PCI label already helps to speed up the permitting, but consideration of other ways to speed up permitting processes would be beneficial. An important step has been made in this regard with the temporary emergency regulation on laying down a framework to accelerate the deployment of renewable energy (COM(2022) 591 final), which was proposed by the European Commission in 2022 and would accelerate permitting for renewable energy projects. Another barrier is the **lack of common European standards** regarding the production, transport and use of hydrogen, which limits the diffusion of hydrogen and its overall potential. The European Clean Hydrogen Alliance has started to work on this and work should be coordinated at the EU level to ensure European standards.

5.1.3. Security of supply and the need for gas infrastructure

Hydrogen will likely only play a role in the security of supply in the long term. To ensure the security of gas supply and affordable energy prices, immediate actions are needed and have been implemented to address the recent crisis caused by the Russian invasion of Ukraine. In particular, we find that a fast and efficient reshuffle of the EU's gas import portfolio would require **a targeted reorganisation of the EU's gas system** to accommodate **structural shifts in gas flows** already occurring across the EU.

Although **substantial progress has been made in increasing gas interconnectivity over the last decade**, particularly in Central and South-East Europe and the Baltics, **several infrastructural bottlenecks are still present** across the EU. The infrastructural bottlenecks in North-West Europe between Belgium, France and Germany, regulatory inconsistencies at the French-German border, and the isolation of the rich LNG capacity of the Iberian Peninsula are among the most crucial. As the largest gas market in the EU, Germany needs to find urgently a replacement for its over-dependence on Russian piped gas; however, other, smaller, markets, including some Energy Community members will need to reconsider their almost 100% dependence on Russian volumes. The **RePowerEU Plan emphasises a need for a regional approach** to allocating investment in additional infrastructure projects that have not been included in the PCI list and that are necessary to re-adjust gas flows. At the same time, a current patchwork of numerous natural gas projects pursued by the Member States in some cases may lead to suboptimal outcomes.

As LNG is becoming a key supply source to re-adjust the EU import structure, entering into long-term supply contracts becomes a political choice as many stakeholders interviewed underlined. The available LNG technical capacity in the EU is sufficient to satisfy almost 60% of the current EU gas demand. However, for years, LNG imports did not cross a fifth of the EU gas portfolio and the average utilisation rates remained low. Competing with piped gas, the EU LNG market remained a 'last resort' one absorbing the excessive volumes from the global market. With Russian gas no longer available, other solutions are to come, including via EU joint purchasing under discussion.

As well, although the volatility of LNG imports into the EU is closely linked to the global supply side, other factors affect terminals' utilisation. The terminals, at which long-term capacity contracts tend to prevail, had higher capacity utilisation. Some of these terminals are exempted from regulated access. Other regulatory settings, such as access rights and services offered at terminals may also affect the rates of LNG procurement. Further harmonisation of LNG terminals' regulation or streamlining their attractiveness to source spot or short-term cargoes may be discussed.

To mitigate the current supply bottlenecks, several Member States fast-tracked the expansion of terminals and new FSRUs, often in record time. Although permitting has remained a sensitive issue leading to slow upgrades in the past years, currently, some Member States exemplified fast-tracking of regulatory approvals.

Gas storage is a key component to getting through winter and providing system balance. Recently, the business case for UGS was challenged with ever-decreasing summer-winter spread, as well as low filling levels in 2021. The Gas Storage Regulation adopted urgently in the first half of 2022 provides an obligation of a minimal EU average of 80% this winter and obligatory certification of SSOs.

In the shorter term, the feasibility to source an additional 60 bcm of LNG and pipeline gas alternative to Russian supplies as stipulated in the RePowerEU will depend to a larger extent on the **supply side,** thus the availability of gas on the global market, as well as on tankers to ship LNG cargoes. Elevated gas prices would further put pressure on industrial gas demand and may require further demand reduction policies. In the short term, the availability of LNG and alternative pipeline supplies is an external factor that could be managed jointly and thus more efficiently. However, a lack of solidarity and national responses to the crises across the Member States have been reported by stakeholders interviewed and various experts throughout 2021-22.

5.2. Policy recommendations

These recommendations are based on our research and in particular the interactions with stakeholders through interviews and a workshop. In the following subsections, we will discuss several key policy areas of interest, highlight key issues to consider for policymakers and provide policy recommendations. We have grouped these along the following policy areas:

- Regulation of the gas market;
- Short-term to medium-term view: Ensuring the security of gas supply; and
- Long-term view: Hydrogen investments and readiness.

Across all three areas, it is key that **Europe does not lose track of its decarbonisation pathway**. Clean energy markets and energy prices are still linked to and influenced by fossil fuel markets, which makes any discussion more complex and external factors such as Russia's invasion of Ukraine can challenge existing ambitions. In this sense, the main goal should remain the decarbonisation of our economy, for which renewable hydrogen can be a useful tool. In addition, **cooperation between Member States on decarbonisation, energy security and the development of gas markets will be key** since gas markets are global and the crisis affects all.

5.2.1. Regulation of the gas market

Based on our conclusions we see the proposed 'Hydrogen and decarbonised gas market package' as an important step forward as it addresses issues identified with the Third Energy Package for Gas and most importantly it caters to the decarbonisation of the gas market. In addition, the flexible and gradual approach will be beneficial to let the market develop while setting **expectations on the future regulatory framework and thereby providing legal certainty.**

Regarding the proposed unbundling regime and the exclusion of the ITO model, we did not find sufficient evidence that supports this. Based on our qualitative review we find that the benefits (reduced regulatory oversight costs by simplifying the unbundling regime) do not outweigh the costs (e.g. discouraging investments from ITO unbundled gas undertakings). Therefore, we consider regulatory alignment preferential and suggest the European Commission **review the proposed unbundling models for hydrogen and aim to align it with the current framework for the existing natural gas market**. While it is true that there are no legacy operators in the yet-to-emerge hydrogen market, there are legacy operators and rules in the gas market, which have been working well in the past and which will also be affected by these changes. Moreover, in past years many gas operators have been transitioning naturally to ownership unbundling. This also likely requires a distinction between the transmission and distribution of hydrogen and clarification of which unbundling models would apply to gas TSOs and DSOs. Thus, regulatory frameworks for (electricity), gas and hydrogen should be aligned where possible to facilitate synergies between the markets.

Regarding network planning, it is key to ensure that the different network plans for gas and hydrogen (and electricity) are aligned and integrated. Experiences of close cooperation between ENTSOG and ENTSOE in developing joint scenarios have shown this being implemented. Until the establishment of ENNOH, ENTSOG has to ensure that hydrogen is integrated into the network planning. With the establishment of ENNOH, **joint scenario development between all three entities is encouraged**.

Nevertheless, while having separate entities can complicate the integration of network planning, it improves transparency and ensures a dedicated entity that knows the needs of producers and users can take responsibility for hydrogen, which will be an energy carrier in its own right. It also prevents vested interests to slow down the transition to hydrogen or proposing the repurposing of otherwise stranded assets for which there would be no particular use for hydrogen.

ACER (together with National Regulatory Authorities) should continue its crucial role in reviewing network plans and providing feedback to the operators and the European institutions. Recently, ACER launched a process to adopt new scenario guidelines used for the electricity and gas Ten-Year Network Development Plans. These new scenario guidelines could improve the neutral assessment of infrastructure projects and the transparency of the developed scenarios. In the near future, considerations on adapting or extending these guidelines to an integrated energy system planning (e.g. including hydrogen as energy storage) should be made.

Barriers that apply to both the development of natural gas and hydrogen infrastructure (as well as RES) are the duration and costs associated with permitting procedures for projects. Key cross-border infrastructure project can already benefit from accelerated permitting procedures under the PCI label, but considering not every project will receive this label further **consideration to speed up permitting processes are needed.** Fast-tracking of permitting procedures has been implemented by some Member States during the current energy crisis, however, these have been short-term solutions and focused on natural gas infrastructure. In the longer term, a European approach to speed up and streamline permitting processes is needed. Therefore, the European Council should **approve the Commission proposal for a Council Regulation laying down a framework to accelerate the deployment of renewable energy** and Member States should make use of the emergency measures under this one-year temporary regulation to accelerate the deployment of renewable energy sources. European institutions should draw lessons from the implementation of the emergency regulation to further improve permitting for key renewable energy and infrastructure projects in the future.

A further recommendation is to provide **a clear definition of renewable and low-carbon hydrogen at the EU level**, which can then be used to derive standards and certification schemes to be used by producers, network operators and industry. Finally, one unknown factor for regulators is the value of an average hydrogen pipeline and how a transfer of pipelines between regulated companies would be implemented. Therefore, **increased regulatory clarity on the repurposing of infrastructure will be needed** to ensure operators will be able to transfer assets.

5.2.2. Short-term to medium-term view: Ensuring the security of the gas supply

Ensuring gas availability for the heating seasons of 2022-23 and 2023-24 from an **infrastructural perspective would require an ad hoc re-arrangement of gas flows throughout the EU**. In the medium term, the advancement of additional infrastructure to complement the current PCI list and the completion of the gas PCIs, as identified in the REPowerEU Plan, would be essential for the EU to complete a phase-out of Russia's gas imports well before 2030.

Short term: 2022-2023

In the current geopolitical context, policymakers should consider further **encouraging regional cooperation on immediate diversification efforts and measures related to demand aggregation. The EU Energy Platform** created under the REPowerEU in April 2022 is tasked to coordinate pooling demand, infrastructure use and negotiations with key exporters and consumers internationally with an option of negotiating voluntary joint gas purchases. Two regional task forces – the South-East Europe regional task force launched in May 2022 and the Central-Eastern regional task force initiated in June 2022 have so far identified the key issues, i.e. infrastructure development, gas demand needs and supply options. Further work is upcoming in the next months, also in light of the newly created voluntary joint purchasing mechanism. Such measures can be applied to facilitate shipping to the regions most affected and the regions where bottlenecks remain.

Redirecting gas flows from North-West Europe to Central and Eastern Europe would need to ensure the effective use of already highly utilised interconnectors. At the same time, it would be essential to mitigate remaining contractual congestion at several interconnection points across the EU, as identified by ACER. In this regard, it is essential to **ensure the availability of existing capacity to avoid whenever possible contractual congestion at interconnection points.**

Although the completion of most of the remaining gas PCIs is still a matter of several years, it is important to ensure now that the barriers that have been inhibiting projects' completion are being removed or substantially mitigated. It would be important to **conduct a 'reality check' of the status and progress of the ongoing key infrastructure projects.** ACER provides annual monitoring and evaluation of progress in the implementation of PCI projects. Based on ACER findings, which reveal several projects that have experienced consistent delays or rescheduling, targeted actions could be effectuated by the relevant parties, i.e. the Commission, NRAs, or regional task forces. In cases when the projects experience significant delays, the Regional Groups could consider additional scrutiny, also requesting justification of the lack of progress and/or reassessment of the respective need, costs and benefits.

Encouraging adequate gas supply to replace Russia's decreasing gas deliveries, it is important **to avoid stranded assets** that may result from the solutions taken in the short-term, even motivated by strong security of supply considerations. As an immediate crisis mitigation, FSRUs have shorter lead times and could allow faster replacement of Russian imports for the duration of their lease. Therefore, it might be practical to encourage **new FSRU lease agreements.** An expansion of the existing regasification capacity would be also needed to re-direct the existing flows. All this implies that **investments into additional cross-border interconnectors** should undergo careful considerations and calculations. Also, **flexible supply options** such as off-grid supply via small-scale LNG, particularly on sites close to industrial demand, can be a short-term targeted solution.

As discussed in section 4.1, some cases of FSRUs or expansion of LNG terminals are crucial to bringing supplies to those particular markets most affected by the withdrawal of Russia's supplies. Therefore, it would be essential to **encourage Member States to adopt and streamline effective LNG permitting processes** for uploading, shipment and regasification of LNG. Good practices of the Netherlands – and probably Germany – reveal that permitting processes can be accelerated to be completed within several months.

It will remain a political decision of whether Member States – jointly or individually – should seek new long-term supply contracts, especially in times of high gas prices. Long-term contracts, on the other side, immune buyers to a certain extent against the volatility of spot LNG cargoes following largely price signals (premium) on global markets. However, also various regulatory settings regarding access rights and services provided at LNG terminals may affect the choice of shippers to direct their cargoes to particular terminals. Although there is no uniform opinion on whether further harmonisation of a regulatory framework for LNG terminals may be useful, it is essential **to check whether the current rules at each terminal facilitate access to short-term and spot cargoes** and whether they can facilitate a functional increase of LNG short-term and spot imports.

A coordinated response to **underground storage filling** introduced by the Gas Storage Regulation can help as an emergency tool. However, it might be needed to leave enough space for flexibility in reconciling the long-time debate about the market and system values of gas storage in the EU.

Therefore, it would be advised to **carefully assess the implementation process and the results of the new storage obligations, e.g. during winter 2022/23**.

Medium-term options: 2024-2030

Completing new gas infrastructure had taken time in the past, largely due to delays in some projects caused by **permitting** and **financing** issues as discussed in section 4.1. For the ongoing PCI projects, the progress needs to be consistently monitored to ensure their completion within the estimated timelines.

At the same time, the re-organisation of the EU gas system invoked by an urgent and relatively unexpected phase-out of all Russia's supplies would require several additional projects that are not included in the current PCI list. **Ensuring the 'Smart Investment' principle** of the REPowerEU Plan would require regional cooperation to avoid sub-optimal outcomes in terms of capacity utilisation of the existing and future infrastructure. When designing new projects, it is important to avoid risks of over-investment in pipeline infrastructure (e.g. the case of the Baltic region) and to increase the effectiveness of new infrastructure (e.g. the case of South-East Europe). Already competing projects, such as three LNG terminals planned in Greece or several LNG projects planned in the Baltics, potentially create overcapacity, and a careful selection of projects may be needed.

The TEN-E Regulation no longer includes gas-related projects and therefore cannot be used to fast-track the additional gas projects required to complete emerging bottlenecks. In that regard, financial support for both planning and construction can help move the process forward, especially if the governments of the Member States in question are financially-constrained. In the past, cross-border projects often invoked long-lasting deliberations on the cost-benefit allocation across the borders, as it is often the case that one Member State benefits from a project to a larger extent than the other(s). For PCIs, a useful tool to calculate cross-border cost allocation has been applied in the past.

The latter is connected to the question of the future use of these assets (stranded assets). For example, the EIB is no longer investing in fossil fuel assets, which sends clear signals to the market. If European gas demand does decline over the next 10-15 years, it will be the Russian supplies that are phased out first, and then non-Russian supplies afterwards. Beyond that timeframe, it is also clear that some **strategic planning should be conducted about using the new infrastructure for decarbonised gas in the future.** For example, Tree Energy Solutions (TES) is seeking to 'future-proof' its LNG import project[262] at Wilhelmshaven with long-term plans to import "hydrogen-based gas". It might be essential to **consider solving stranded asset issues by ensuring hydrogen-ready gas infrastructure,** including LNG terminals, gas interconnectors and storage, which can be made ready for hydrogen injections gradually. Among others, forthcoming German LNG terminals are envisaged as 'future-proof' to import hydrogen. However, as discussed in chapter 3, the technological feasibility of converting terminals to allow hydrogen intake needs more discussion. Beyond 2030, the conversion of gas storage to accommodate hydrogen storage may come in competition with the relevance of storage for securing certain volumes of natural gas in case of emergencies.

[263] There are a few pipelines for which already now one can foresee future needs, for example connecting the ports of Rotterdam and Antwerp with industrial clusters in France and Germany.

5.2.3. Long-term view: Hydrogen readiness and uptake

While hydrogen has received increased attention during the current crisis, policymakers should be careful to consider it a miracle solution. In the coming five years, there will be no EU-wide market for hydrogen as demand is only developing. Currently, hydrogen is mainly used for industrial use where we see also further potential, while its future use in other sectors such as transport (e.g. heavy-duty vehicles) or storage for energy flexibility is not yet clear. It will require more than just higher gas prices to introduce hydrogen and transform our economy: **Risk-taking supported by political action will be needed to set the groundwork and accelerate this process**.

The EU 'Hydrogen and decarbonised gas market package' takes the first step by providing a clear regulatory framework. This has been complemented by supporting actions (see 5.1.2). Beyond this, further actions can help set the ground for hydrogen by:

- Ensuring a sufficient supply of renewable energy sources;
- Preparing infrastructure both for importing hydrogen and for serving industrial clusters; and
- Addressing barriers to investing and funding hydrogen projects.

The **lack of renewable energy is a bottleneck for the production of renewable hydrogen** that needs to be addressed if the EU wants to transition to hydrogen. Therefore, the success of hydrogen is dependent on the availability of renewable electricity. While there will likely be sufficient renewable energy available to reach the REPowerEU target of 10 million tonnes of domestic renewable hydrogen production in 2030, this energy is also needed in other sectors.

Therefore, to prepare the ground for the transition to hydrogen, policymakers should:

- Assess and **decide on priority sectors for hydrogen deployment** so scarce renewable energy is used initially only to produce hydrogen for those sectors that need it and once more renewable energy becomes available consider rolling out hydrogen more widely;
- In the meantime, **continue the work on energy efficiency** to free up renewable energy and simultaneously reduce the need for hydrogen by following the EU's "energy efficiency first principle" and work towards the EU energy efficiency targets as outlined in the Energy Efficiency Directive, the Energy Performance of Buildings Directive and the proposed increased targets of the REPowerEU plan. Member States need to contribute to this by following up on their national action plans and implementing their long-term renovation strategies; and
- Finally, while not the focus of this study, continued **support and investments into renewable energy sources** through the already existing programmes and funding allocated through NRRPs should be ensured. Member States should consider using additional funds from the loan compartment of the RRF for additional investments into renewable energy. A key issue to address here (similar to infrastructure) is that **permitting processes take too long**. This is partially due to environmental regulations, bureaucracy and local opposition. Permitting can take up to 8 years. As discussed in 5.2.1, the proposed emergency Council regulation will help in speeding up some processes, but the Member States and the EU will need to find ways in the future to further streamline processes and align energy and environmental targets.

Beyond renewable energy, **another bottleneck is the current lack of infrastructure to transport hydrogen**:

- With current development being driven mainly by policy instead of market demand, it is important to **ensure proper discussion between policymakers, producers, network operators and industry need to combine infrastructure planning** to be able to bring hydrogen where potential demand will be. When considering developing hydrogen production, the availability of sufficient renewable energy in the vicinity should also be considered. This will allow for better infrastructure planning and will ensure hydrogen investments are focused on areas where they will be needed. Policymakers should be wary of just supporting any project and instead closely align with the industry currently relying on natural gas on how and where they see demand developing. A forum for such an exchange at the EU level could be the Industry Advisory Group set up as part of the EU Energy Platform. Similar groups could be set up at the Member State level. Similarly, network operators have already started this process by ENTSOG integrating hydrogen in its network planning. In discussion with ACER and National Regulatory Authorities, this should be continued to identify key hydrogen infrastructure projects (i.e. no-regret projects[263]) and ensure their implementation by 2030;
- As outlined in REPowerEU, the EU will also rely on imports of renewable hydrogen. This will require network operators to **consider ports of imports in their network planning** and how these can be connected with areas of demand in different Member States. Policymakers will also need to enter into discussions with third countries on the possibilities of exporting renewable hydrogen. Finally, to facilitate the import of hydrogen, international standardisation regarding the production, transport and use of hydrogen (i.e. required purity levels) should be supported. The European Clean Hydrogen Alliance has started to work on this aspect and work should be coordinated at the EU level to ensure common European standards; and
- Building on the discussion of the short-term security of supply (5.2.1), **it is also key to ensure readiness for low-carbon gases in new gas infrastructure** that is being built as a reaction to the current crisis. Renewable hydrogen can be seen as a solution next to e.g. biomethane. Already, NRRPs consider this and it should be ensured that in the ongoing discussions between the Member States and the European Commission to update these plans under REPowerEU additional considerations for the future use of pipelines for the transport of hydrogen are taken. This will reduce repurposing costs and reduce the risk of stranded assets, which are both main barriers to starting projects. Another question is the potential of repurposing LNG terminals for hydrogen. Currently, there are some ambitions by the industry of making this possible to avoid ending up with stranded assets, however, this is highly theoretical and due to the differences in hydrogen and methane gas one cannot expect this at the moment to be cheap or effective. Further research will be needed before any promises should be made that these can be repurposed.

[263] There are a few pipelines for which already now one can foresee future needs, for example connecting the ports of Rotterdam and Antwerp with industrial clusters in France and Germany.

A **third bottleneck to address is the large amount of financing needed** to support the development of new infrastructure. This requires:

- EU and national policymakers to **follow up with existing funding programmes** such as IPCEIs and PCIs under TEN-E (see section 3.3.3) and ensure awareness about these opportunities;
- **Investigate additional ways to provide EU and national level funding for hydrogen projects**, for example by Member States updating their NRRPs and accessing additional funds from the currently underused loan compartment of the RRF; and
- Beyond public funding, **hydrogen projects will be financed by users through network tariffs**. However, as outlined the risk is that these would be too high for initial users and therefore become an insurmountable barrier to hydrogen uptake. An alternative proposed in the 'Hydrogen and decarbonised gas market package' is the limited use of **cost mutualisation**, whereas a dedicated charge could be applied to gas networks to finance hydrogen networks. This can transfer the development costs of hydrogen networks to the larger gas user base, which would ensure that hydrogen becomes an affordable alternative also in the early transition period. However, this would shift the burden to the current users of natural gas including households. Considering the already high energy prices, Member States need to investigate together with their National Regulatory Authorities and consumer organisations if and how these can be applied to finance hydrogen infrastructure and likely a combination of public subsidies, network tariffs and cross-subsidisation will be needed. An alternative proposed by regulators could be to introduce inter-temporal cross-subsidies, whereby a share of cost recovery would be shifted later in the future and be borne by later users of the hydrogen network.

ANNEX

Annex 1 – Additional information on underground gas storage capacity

Table A.1. Types of underground gas storage and working gas capacity (WGV), 1 October 2021

	Type of UGS			WGV (TWh)	% WGV from Annual gas consumption
	Depleted fields	Aquifers	Salt caverns		
Austria	100%			95.48	102.3%
Belgium		100%		9.00	4.7%
Bulgaria	100%			6.27	19.3%
Croatia	100%			5.22	15.5%
Czech Republic	98%		2%	36.07	38.4%
Denmark		55%	45%	9.08	29%
France		90%	10%	128.46	28.5%
Germany**	43%		50%	274.72	28.6%
Hungary	100%			67.70	59.8%
Italy	100%			197.73	26.3%
Latvia		100%		21.80	185.8%
Netherlands	97%		3%	143.81	35.2%
Poland	74%		26%	35.79	16.3%
Portugal			100%	3.57	5.3%
Romania	100%			32.99	25.9%
Slovakia	100%			38.75	73.6%
Spain	84%	16%		35.25	9.5%
Total* **	**9**	**5**	**8**	**1140.70**	**27%**

Source: ACER, 2022(a), Report on gas storage regulation and indicators.

Note: **missing 7% are commercial storage zones consisting of both types of storage with no available information about the exact volumes; *** in addition, 3 storages of depleted aquifers.

Annex 2 – Organisations that were interviewed or participated in the workshop

Table A.2. Types of stakeholders who contributed to the research

Number	Organisation
1	The European Union Agency for the Cooperation of Energy Regulators (ACER)
2	Council of European Energy Regulators (CEER)
3	The European Centre for Climate, Energy and Resource Security (EUCERS)
4	European Commission, Directorate-General for Energy (DG ENER)
5	European Network of Transmission System Operators for Gas (ENTSOG)
6	Florence School of Regulation (FSR)
7	GASCADE GmbH
8	Gas Infrastructure Europe (GIE)
9	Katholieke Universiteit Leuven (KU Leuven)
10	Oxford Institute of Energy Studies (OIES)
11	Open Grid Europe GmbH (OGE)
12	Vereinigung der Fernleitungsnetzbetreiber Gas e. V. (FNB Gas)
13	Energy consultancy
14	Energy consultancy
15	RiEnergia

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This study takes a closer look at the proposed revision of the Third Energy Package for Gas. The report reflects on how the revision and the foreseen unbundling rules affect the transition to a hydrogen-based gas economy. Apart from the long-term view and in consideration of the current energy crisis, the report also reflects on short-term options to ensure stable prices and security of supply through new EU gas interconnectors, liquefied natural gas imports and underground gas storage. The findings highlight the challenge of guaranteeing security of supply through new investments in natural gas infrastructure while simultaneously developing a hydrogen infrastructure, which is currently not pulled by market demand but driven by policy objectives for decarbonisation and increased autonomy. Achieving this will require both public support and risk-taking from involved actors in the hydrogen market.

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