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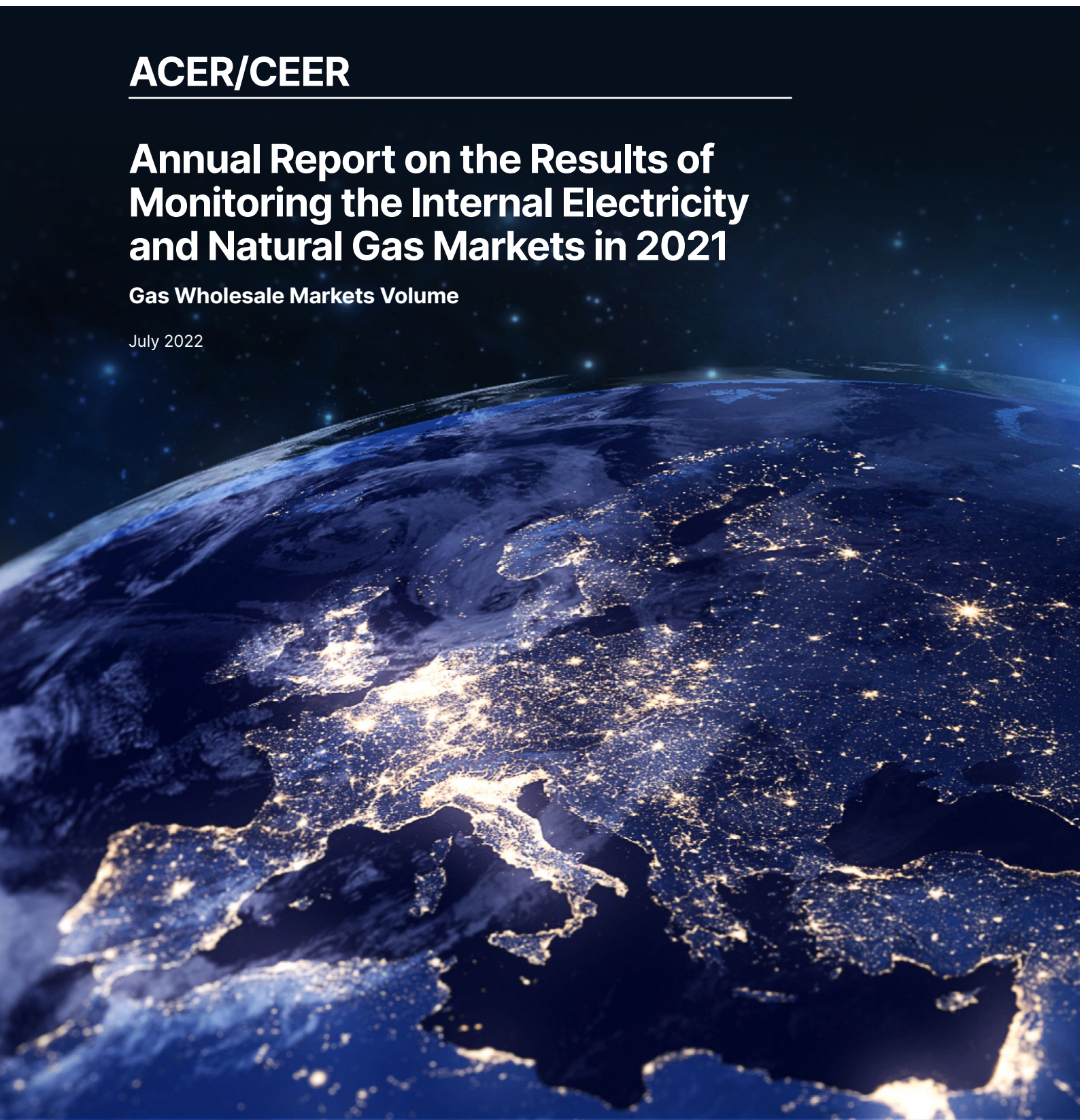


ACER/CEER

Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021

Gas Wholesale Markets Volume

July 2022



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Executive Summary

- 1 The Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) are publishing the eleventh edition of the annual Market Monitoring Report (MMR), produced in cooperation with the Energy Community (EnC) Secretariat. The MMR consists of several Volumes that cover different EU energy market segments.
- 2 This Volume provides an overview of the status of the European Gas Wholesale markets in 2021 and the first half of 2022. ACER and CEER will publish two more MMR Volumes in the course of autumn 2022: a Retail and Consumer Protection Volume, which will review the impacts on consumers of the record high energy prices and another volume that will examine the regulatory provisions and market context of decarbonised gases and hydrogen.

High global LNG prices and restricted Russian gas flows send EU gas and electricity prices soaring

- 3 Gas prices have surged and reached the highest levels ever observed in the EU at the end of 2021. However, new price records were set in March 2022 following the Russian invasion of Ukraine¹. As outlined in ACER's recent Assessment of EU Wholesale Electricity Market Design, issued in April 2022², the current energy crisis is in essence a gas price shock, which also impacts electricity prices. This is due to the linkage between gas and electricity prices. This linkage has also driven electricity wholesale prices to historical highs in many markets, particularly where gas-fired electricity plants set short term electricity prices³.
- 4 **Figure 1** shows that the gas price surge can be split into three distinct phases.
 - a) Phase one – A decrease in liquefied natural gas (LNG) imports and narrow pipeline flows led to the first wave of the price rise across Q2 and Q3 2021, amid increasing gas consumption resulting from the economic recovery from the COVID-19 pandemic.
 - b) Phase two – From autumn 2021, the decreasing volumes supplied by Russia placed significant upward pressure on EU gas prices despite a gradual increase in EU LNG imports. This occurred in a context of low underground storage stocks due to Gazprom's insufficient gas injections.
 - c) Phase three – the Russian invasion of Ukraine on 24 February 2022 resulted in extreme uncertainty as to the near-term outlook for gas supplies to the EU. This placed further upward pressure on gas prices. The impact of EU sanctions and Russian countermeasures has been reducing the supply of contracted gas volumes to the EU since then, creating concerns regarding supply adequacy and adding tensions to prices⁴.

1 The price data collection for this Volume was completed on 30 June 2022.

2 Following a request from the European Commission, [ACER's Assessment of the EU Wholesale Electricity Market Design](#) assessed the suitability of the current electricity market design to deliver on the clean energy transition. While the analysis focused on the long-term perspective, the assessment also discussed short-term measures to tackle current price shocks.

3 Gas-fired plants often set marginal electricity prices in a majority of EU power markets, while when hydro plants or coal act as price setting-units instead, they tend to relate their opportunity cost to the costs of generating electricity with gas. However, the situation varies per jurisdiction. At some renewable electricity generation may also often fill the merit order.

4 Russian gas flows to Poland and Bulgaria were cut in late-April 2022 under the stated pretext of not meeting the payments of prevailing contracts in roubles. In May 2022, Gazprom deliveries to Finnish Gasum were also interrupted. In the first half of June 2022, Gazprom also halted supply to the Dutch Gastera and to Denmark's Orsted, as well as to various other gas companies such as Gazprom Germania and its subsidiaries and Shell Energy. In mid-June 2022 Gazprom also significantly reduced flows to Germany via Nord Stream 1 alleging technical problems with the compression equipment, which led to significant flow drops into Germany, Italy, France and Austria.

Figure 1: Overview of events and market fundamentals driving EU gas prices through the lens of Dutch TTF hub month-ahead contract – May 2021 – June 2022 – euros/MWh



Source: ACER based on ICIS Heren's price data.

- 5 The market sentiment, which is subject to significant volatility, suggests that gas prices will remain extremely high in the coming months. This is driven by concerns regarding supply ahead of next winter. High price levels are also expected in the mid-term horizon. For example, in early June 2022 gas offered for forward delivery at EU hubs in Q1 2024 surpassed 60 euros/MWh, which is twice the increase over the average price of the last seven years. This is because Member States have committed to minimize Russian gas imports into the EU over the coming years⁵. This has constrained alternative pipeline and domestic incremental supply options whilst the LNG market is expected to remain tight as a result of global competition. Such a high price scenario is likely to persist until substantial new production capacity becomes available.

Reassessment of supply diversification options and demand reduction: the RE-PowerEU plan

- 6 Significant supply changes occurred across 2021, and intensified in the first half of 2022. This resulted in LNG increasing supply volumes to Europe to address the reduction of Russian supply. As Figure 2 shows, in the first part of 2021, LNG imports fell below previous years' average, as global competition for LNG resources drew gas away from EU markets to the higher priced Asian markets. However, LNG imports rebounded from Q3 2021 in response to stronger EU hub price signals. LNG imports are reaching record highs in 2022, with LNG deliveries from the United States leading the rise.

⁵ Member States have expressed the overall political goal to shift away from Russian supply by 2027 at the latest. Various Member States have set earlier deadlines; e.g. Lithuania, Latvia and Estonia already stopped its Russian gas supplies in April 2022, Germany plans to do so in 2024 and Italy in 2025. As mentioned, Russian gas supplies to various other Member States have already been halted or reduced.

Figure 2: Comparison of European and Asian wholesale price spreads vs EU+UK LNG and Russian pipeline imports – 2021 to July 2022 – euros/MWh and bcm/period



Source: ACER calculation based on ENTSOG, Refinitiv and ICIS Heren data.

Note: *For Phase 1, the year 2019 is used as a reference for comparison, given the non-typical imports across the first semester of 2020.

- 7 While gas prices have hit record highs and sources of gas to the EU shift, it is important to note that the interconnected EU gas system has ensured that gas continues to flow to EU consumers in response to price signals. However, the usual gas supply security margins have been limited in a context in which Russian volumes have fallen by more than a third. This reduction in gas supply margins has resulted in the European Commission and Member States calling for increased EU underground storage stocks ahead of the next winter season. A target to fill EU storage stocks up to 90% of their capacity before November has been established (the target has been set at 80% for the year 2022, the first year of stockpiling). The filling obligations would expire on December 2025.
- 8 The Russian attack on Ukraine represents a turning point for EU energy supply security. Subsequent sanctions and political positions of the European Commission and Member States have enhanced the drive to further diversify energy supply to European consumers and minimise the dependence on Russia as fast as possible. To enhance the speed of energy diversification, the European Commission issued the REPowerEU Plan in May 2022⁶. REPowerEU establishes a roadmap of measures to reduce the energy supply dependency on imported Russian gas. The measures include promoting more diversified energy supplies as well as increasing renewable energy installation and penetration. The strategy puts forward a 30% reduction in the final EU gas demand by 2030. Gas demand has fallen by 9.5% YoY to May 2022, in view of the high prices leading to industrial demand destruction in energy intensive sectors and in response to the efficiency measures being implemented.

6 The REPower EU Plan gathers a number of initiatives to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition.

The gas market design gets attention: which mechanisms can deliver price affordability whilst ensuring security of gas supply in a tighter supply environment?

- 9 The extremely high energy prices have led to questions and debate about the suitability of the gas and the electricity market designs. As previously mentioned, following a request from the European Commission, ACER issued an assessment of the EU Wholesale electricity market design in April 2022. In the margins of this work, questions have also been raised with regard to gas wholesale market, in view of checking if the current market design is able to respond to a temporary shock or if it needs to shift to be more performant. Discussions involving the gas sector are focused on finding policy responses to secure supplies and to hedge price exposure. While measures initially strive to preserve competition and market integration, some of the shocks are so extreme that the regular market instruments might not always work. Hence, there are calls to introduce more interventionistic measures, such as joint purchasing or price caps. The debate at the same time touches upon the EU energy systems' external dependence on gas and the potential contribution of gaseous energy to meet the climate goals.
- 10 The significance and structure of long-term gas supply contracts going forward is an important issue being reconsidered. Despite the fact that long-term contracts have declined in recent years and will likely continue to do so, such historical contracts still account for 80% of EU gas demand (around 40% of long-term contracts are signed with Gazprom). New long-term contracts are being negotiated in the last few months to secure new supply commitments, for example from LNG producers.
- 11 Another issue under scrutiny relates to the future function of underground gas storages. Gas storages provide security of supply during high demand periods (exerting downward pressure on prices during tight supply situations) as well as support flexible system operation. Given the uncertainty of future Russian gas flows, the security of supply role of gas storage sites across the EU has been reinforced with new regulatory measures.

Recommendations

- 12 In response to the current energy crisis, the gas wholesale market design discussions are focused on finding the most appropriate policy response to secure gas supplies and to limit high price exposure. While preserving the competition and market integration elements of the current market design remains important, securing supply from alternative sources and accelerating demand savings have become more pressing issues in view of the radical shift away from Russian supply. In this context, there have been calls for reevaluating the gas contractual mechanisms and the role of hubs. The exposure of EU electricity wholesale prices to spot hub gas prices is another element that influences the debate and raises pertinent questions about the missing investments in flexibility tools.
- 13 Given the present-day scenario and its geopolitical complexity, ACER's recommendations focus this year solely on issues relating to the current crisis. Below, the context of the two key general areas under discussion is initially introduced, followed by some opening considerations and then more explicit recommendations to help address the current crisis.

Area I: The gas contractual equilibrium attracts renewed attention

Context

- The current EU gas market design has at its core ideas of competition and enhanced integration between liquid hubs. The design has been instrumental in increasing price integration and in delivering competitively priced gas when gas supply was amply available. It has also ensured continued gas supply across Europe, including to and from Ukraine, under extremely challenging circumstances.
- However, the latest market developments have revealed some vulnerabilities in the model. These vulnerabilities relate to decreased control of physical gas volumes by EU companies in a context where supply competition at gas hubs is partial, which can consequently limit competitive price formation⁷.
- While the current high prices do not diminish the importance of the *hub-based* model overall, the question is how well it fits the distorted market setting and supply security needs of present times.
- This is all the more concerning because the high hub prices have pushed the prices up for the majority of long-term gas supply contracts, which are today typically, though not exclusively, linked to hub-price references⁸. This also means that Gazprom, and thus the Russian state as the majority shareholder in Gazprom, benefit from the significant price increases in the EU gas hubs.
- The European Commission and a number of Member States and major EU companies are aiming at securing new supply commitments under new long-term contracts in the last months, including negotiating their price indexation.

Opening considerations and Recommendations:

What to preserve?

- Hub price signals in conjunction with hub trading and contracting have attracted additional flows into the EU ensuring security of gas supply. They have also eased flow transfers among EU markets and final users, ensuring gas was delivered where it was in highest demand. As such, these hub price signals should be structurally preserved in the long-term, as they sustain market integration and contribute to easing supply shortages.

7 In spite of some non-EU producers gradually making more gas directly available at hubs, the majority of the volumes traded at hubs correspond to suppliers hedging their supply portfolios and to financial traders. While both are key to enhancing hub liquidity and price discovery, they have less physical volumes in control to counterbalance periods of restrained supply. Those with long gas positions - gas producers, EU suppliers with favourably priced contracts and/or well hedged traders might have also significantly benefitted from selling gas at the record high prices.

8 In spite of that, long-term contract prices generally became somewhat more favourable compared to hub spot prices, depending on the time-lags and conditions of their price formulas.

What to accelerate?

- Re-establishing security of supply is key to smoothing out the pressure on prices stemming from the current market context. While improved supply competition at gas trading hubs would contribute to putting downward pressure on prices (also further promoting competitive price formation⁹) it will be difficult to rapidly secure substantial long-lasting physical deliveries at hubs in next months.
- In view of these circumstances, market participants need to reconsider their supply procurement strategies. This may entail prolonging or adopting new long-term supply contracts¹⁰, as well as revising or agreeing to the elements used in their price formulas. The European Commission and Member States can assist market participants in that process, by means of the common EU Energy Purchase Platform. The platform aims at increasing EU buyers' negotiation power and, by pooling demand, it could also contribute to avoiding instances where EU buyers outbid each other to attract additional volumes, which drives upward pressure on prices. However, gas hubs should maintain their central role in gas trading and gas price discovery. Moreover, given the current crisis, enhancing the collaboration with EU international partners to explore ways to limit prices via acting both on the supply and demand sides is imperative in the short-term.
- Although these actions go beyond regulatory aspects, ACER overall recommends that if EU gas buyers decide to sign new long-term supply contracts, they should aim at obtaining as much supply flexibility as possible from the sellers, taking into account the energy transition targets and the expected future reduction in EU gas demand. This entails for example securing the possibility to divert LNG volumes or the ability to periodically revise the extent and length of the contractual agreements¹¹.

What to change?

- Regulatory measures to install oversight over interval price limits at gas trading hubs could help to avoid excessive market volatility. While the price limits may pose risks to attracting flows in days of significant supply scarcity, they can prevent undue hub price spikes led by possible speculative moves and hence are worth exploring in the short-term¹².
- ACER also considers that there is a need to better monitor the new and prevailing supply contracts, to enhance the transparency of the contractual conditions and better understand the market situation while ensuring confidentiality of information. ACER recommends the EC to implement centralised and mandatory reporting of long-term contracts within the EU, including price formulas and end dates¹³.

9 Enhanced hub forward liquidity would particularly help to hedge prices and reducing price exposure.

10 Europe's long-term contracted LNG volumes will decrease by over 40% in 2026 compared to 2021. In case new long-term contracts are not signed and/or old contracts are not renewed, this would further expose EU LNG buyers to spot market dynamics. It is also of note that a number of new LNG production projects, such as in the US, require long-term contracts to develop the investment. A variety of Asian buyers are signing and willing to sign those contracts to secure deliveries.

11 Another option would be for aggregators to step in and draw contracts with initial delivery to Europe, while later shifting deliveries to Asia.

12 The recent European Commission communication on short-term energy market interventions offers some considerations on the subject. Those price limits would have a rolling nature as opposed to more static price caps.

13 While under the REMIT regulation information on the matter is collected, the contracts covered are only those for delivery within the EU (which excludes a number of contracts delivered at the flange) while the price formulas are only descriptive. National Regulatory Authorities could oversee and provide the data for the individual markets.

Area II. Preparation for the next winter(s): enhance infrastructure flexibility, demand savings and planning and monitoring activities to facilitate this goal

Context

- 14 The usual supply security margins have been reduced as a result of the decreased Russian gas supply and are of particular concern ahead of next winter.
- 15 Moreover, the gradual shift away from Russian pipeline supply, followed by ever-increasing LNG imports, is revealing capacity constraints in the system. This requires a reallocation of transmission capacities combined with targeted infrastructure investment.
- 16 Underground storage filling levels were increasing, on track to meet the targets set for next winter. However, a sustained loss of Russian pipeline flows via Nord Stream 1 could create more problems to meet storage targets and/or could end up in regional disparities with regards to storage stock levels. In the event of a complete disruption of Russian supply there is clear risks of demand curtailment occurring in most MSs¹⁴.
- 17 High gas prices have sharply reduced parts of industrial demand in the energy-intensive sectors. Enhanced efficiency and demand side response measures are also partly contributing to the demand drop, but they will require some more time to be implemented and internalised.

Opening considerations and Recommendations:

What to preserve?

- The widely interconnected EU gas system has kept accommodating flows in response to price signals and delivered uninterrupted security of supply despite the severely challenging circumstances. Hence, various features of the gas system are worth preserving structurally going forward:
 - i. Low barriers to cross-border trade, brought about by among other factors harmonised network codes, have made it easier to trade gas to also reach those markets most directly affected by halts in Russian supplies. Therefore, relevant national regulatory authorities are called on to keep fully implementing network codes' provisions. Moreover, regulators should frequently assess and consult with gas sector participants if the codes could be adapted where appropriate, to better address today's challenging circumstances.
 - ii. Selected new infrastructure investments and improved cross-border transportation capacities developed in recent years, including enhanced reverse flow capabilities, have enabled diversifying supply away from Russian gas and redirection in flows larger than otherwise would have been possible; NRAs and MSs should continue to apply a coordinated regional approach when approving new infrastructure investments in view of optimising financial resources and maximising market integration.

What to accelerate?

- To enable the shift away from Russian gas, new planned infrastructure investments are focusing on expanding LNG import capacities and on removing interconnectors' congestion to enhance LNG flows into non-coastal markets. Speeding up those investments, to make them operational in the short to mid-term, under a regionally coordinated approach is necessary to optimise financial resources. To do that, the communication and transparency about the system bottlenecks must be complete, making coordination and solidarity core principles. An aspect that warrants also specific attention is addressing the barriers to cross-border gas flows that are related to differences in odorisation/gas quality

14 A number of scenarios are on the table. For example, the most severe scenario of the ENTSOG Summer Supply Outlook indicates that a majority of MSs would rely on storage withdrawals to satisfy summer 2022 demand. In that event cross-border flows will reach limits in both North-Western and Southern Europe, while risks of demand curtailment will emerge in most Member States.

standards in some EU gas transmission systems.¹⁵ As stated in the EU related secure gas supply legislations¹⁶, Member States are required to put in place the necessary technical, legal and financial arrangements to make the provision of gas solidarity feasible.

- In addition, Congestion Management Procedures (CMPs) need to be properly implemented to enable network users access to unused contracted transportation capacities. ACER recommends to the European Commission to revise the current CMP Guidelines and to analyse if the effectiveness of the current measures can be enhanced, in particular to accelerate the detection and release of unused capacities on a monthly and quarterly basis. Besides, Transmission System Operators (TSOs) must enhance coordination to maximise capacity offering, including implementing a more dynamic approach to capacity (re-)calculation¹⁷. Finally, the sizeable congestion rents (i.e., auction premium) arising at selected cross-border points that are in high demand for rerouting LNG flows should be used to promote targeted new investments that alleviate these congestions.
- In parallel, ACER backs the rapid implementation of demand saving strategies by Member States and the European Commission. While action will be taken at Member State level, it would be beneficial to agree on demand saving principles, whilst allowing flexibility as well to better adjust to Member States' needs¹⁸. Considerations to campaigns and/or regulations to reduce space heating consumption should be considered both at Member State and at EU level. In addition, the allocation of significant budget to unlock the potential of energy efficiency investments, in particular in space heating and cooling and in transport, should be done based on sound cost-benefit analyses.
- With regard to new infrastructure investments, it is acknowledged that they can pose financial risks for consumers. This is because in the mid to long-term, the role of unabated natural gas in the EU energy system will significantly decrease as a result of the energy system electrification and the targeted demand reductions. This creates a risk for new asset investments becoming stranded. Therefore, ACER recommends that any new gas infrastructure critical to addressing the supply challenge shall also consider as investment decision criteria its prospective significance to flow hydrogen¹⁹.
- Finally, ACER supports that emergency plans, including the organisation of gas demand reduction, be revised and if necessary reinforced by all Member States, within the framework established in the EU related to security of gas supply legislations. These plans will be critical in the event of a full or partial disruption in Russian flows or in case that Member States decide to halt Russian imports in a forthcoming sanction package. Coordination and good communication regarding such plans are necessary to maintain a coordinated approach in response to the existing energy crisis.

¹⁵ see the ENTSOG Summer Supply Outlook 2022.

¹⁶ Various [EU legislations](#) help to prevent and respond to potential gas supply disruptions. Regulation (EU) 2017/1938 on measures to safeguard the security of gas supply being the referential text.

¹⁷ The [ACER Report](#) assessing congestion in the EU Gas Markets further elaborates on those Recommendations.

¹⁸ For example, Member States such as Austria, Germany, Italy and the Netherlands have recently taken decisions to extend coal-fired power generation to cut down on gas use, based on their specific coal generation portfolios and regulations. Refined methodologies tracking how gas is used in industrial supply chains is also important. Best practices could help in coordinating approaches and understanding the differences that may be present on a country by country level. Industrial supply chains extending across Member States shall be assessed through a close dialogue between the countries, which might be facilitated by the European Commission if needed. Critical end-products, such as food and health care goods need to be considered in this context.

¹⁹ In fact, following the EU energy transition ambition, the TEN-E Regulation had set new eligibility rules for funding cross-border energy infrastructure with the mandate of solely financing low-carbon infrastructure.

What to change?

- The demand side needs to play a bigger and more active role in rebalancing the gas market. More predictability towards demand-side adaptations would favour consumption drops, contributing to release pressure on prices. This could be promoted with competitive processes that compensate those industrial consumers that offer to limit consumption for a certain volume and/or certain period of time. The conditions of such mechanism, which could be either done via tendering offers or via an organised auction process need to be further explored and developed based on existing practices and developing ad-hoc IT platforms. Moreover, it is advised to establish a clearer regulatory framework that would help facilitate interruptible supply contracts. Such a framework would help to define the flexibility measures that might notify the interruption in supply to participating consumers, based on contractually agreed pre-determined conditions.
- The insufficient stocking of underground gas storages by Gazprom in 2021 clearly showed gaps in the EU gas storage market regulation. This applies in particular to the absence of Use-It-Or-Lose-It provisions for gas storage capacity in some Member States. In addition, during the initial periods when the Summer-Winter spread turned negative, there was no mechanism in place to ensure gas storages would be filled in the face of financial disincentives. The revised Gas Security of Supply Regulation and various Member States initiative go some way towards addressing these issues in the short-term. The measures need to be developed further to ensure the storage regulation is structurally resilient against such external shocks. Finally, Member States shall closely monitor the curtailments of Russian supply and its impact on storage filling trajectories.

Introduction

- 18 This volume of the Gas Wholesale MMR presents the results of monitoring the European gas wholesale markets in 2021 and the first half of 2022. This volume is divided into three analytical chapters.
- 19 [Chapter 1](#) presents the status of the Internal Gas Market in 2021 and the first half of 2022. The initial sections of the chapter first summarize the main supply and demand developments occurring throughout the period. The chapter continues analysing the various interconnected drivers that stirred a rapid escalation in prices from Q2 2021 onward. Then follows the analysis of the prevailing volumes sourced under bilateral contracting today across the EU. After that, it offers an overview of the cross-border flows and infrastructure developments. Finally, the last two sections offer a deeper assessment of the utilisation of LNG and underground storage infrastructure than in previous editions, discussing their key market drivers and perspectives.
- 20 [Chapter 2](#) assesses the performance of the individual national gas markets in 2021 by means of calculating the so-called ACER Gas Target Model metrics. These metrics evaluate on the one hand the structural competitiveness of the national gas markets and on the other hand the transactional activity of their hubs. The chapter initially discusses the evolution of gas sourcing costs across individual MSs and the evolution of their supply diversification. The chapter also includes a case study that discusses market developments and the regulatory provisions that have backed the liquidity and progression of the Lithuanian hub in the recent years.
- 21 [Chapter 3](#) examines the market effects brought about by the implementation of the gas Network Codes. The chapter contains individual subsections which outline the results of analyses related to NC implementation. These subsections in turn outline considerations that help to contextualize the results.
- 22 Finally, it is important to note that most of the analyses included in [Chapter 1](#), as well as the reporting of key market developments cover the timeframe until the end of June 2022. However, the ACER Gas Target Model metrics assessed in [Chapter 2](#) and the majority of the analyses related to market effects of gas Network Codes cover only 2021. This is chiefly due to data availability. The timeframe covered in each individual figure is specified in the heading.

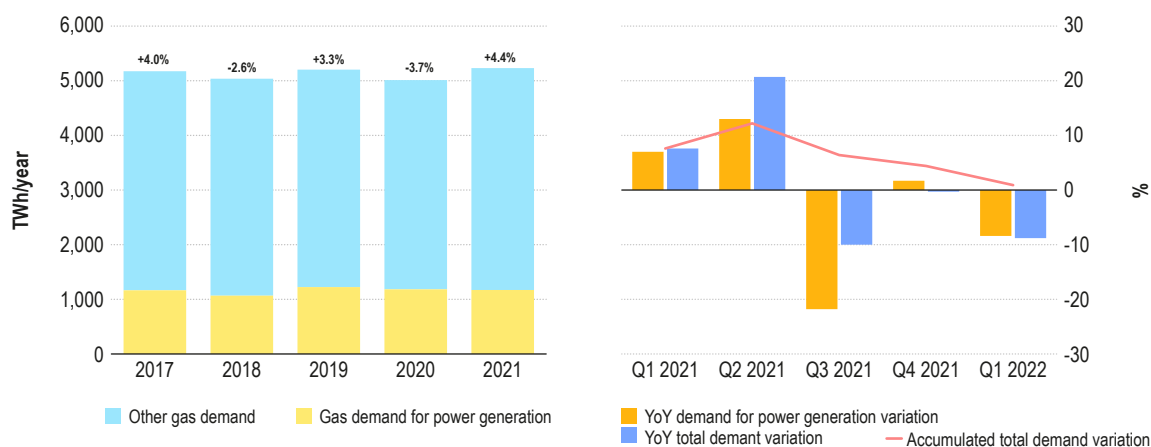
1. Overview of the Internal Gas Market

1.1 Market developments

1.1.1 Demand Developments

- 23 Demand for gas in the EU and UK rose by 4.4% in 2021, with sound variations between quarters. Gas consumption reached five-year maximums in the first half of 2021 (+12% YoY) sustained by the significant economic recovery following the COVID-19 pandemic (e.g., industrial consumption rose by circa 15% YoY in that period). The growth in demand was driven as well by a prolonged winter followed by a warmer than average summer season and by a growing demand for gas for power generation due to subdued wind power production.
- 24 In Q3 and Q4 of 2021, demand fell by -4% YoY. The decline was driven by the high gas prices reducing the competitiveness of gas-fired generation, in conjunction with industrial demand drops in a number of energy intensive sectors (e.g., fertiliser, cement, steel). More generally, the higher energy prices (not only gas) resulted in higher inflation that reduced economic activity²⁰ (inflation hit a decade-high 8.6% YoY in June 2022). The reduction in gas consumption was more pronounced in the first half of 2022 (-9.5% YoY to May 2022). This reduction was the result of market concerns following the Russian invasion of Ukraine, which prompted demand-side response measures and energy efficiency enhancements alongside a mild winter.
- 25 Figure 3 (right) shows the demand evolution across 2021 and Q1 2022 while the left part shows the breakdown of gas consumption in the last five years.

Figure 3: EU+UK inland gas consumption YoY and quarterly evolution – 2021 and Q1 2022 - TWh/year and % of variation



Source: ACER calculation based on Eurostat.

- 26 Higher gas demand elasticity was observed during the year in view of the extreme high prices. This was evidenced by the sharp declines in gas consumption in industrial sectors that were more exposed to the record-high gas prices²¹ and by the decreased use of gas for electricity generation. The weakening of the competitiveness of gas for electricity generation resulted in significant gas-to-coal shifts during Q3 and Q4 2021. This was despite increases in the price of carbon emission allowances, which pushed the carbon emissions of the EU power sector about 20% higher YoY²² (see Section 1.1.3.2 for more information).

20 In accordance to Eurostat data, the (seasonally adjusted) EU gross domestic product rose by 0.5% in Q4 2021 and by 0.7% in Q1 2022, vis-à-vis the preceding quarter. This is sharp drop in comparison to a 2.2% growth across Q2 and Q3 2021.

21 EU industrial gas demand dropped YoY by 6% in Q4 2021 and by 9% in Q1 2022. Some of this is due to reduced production by certain energy-intensive users.

22 See a comparison of coal and gas-fired generation technologies' profitability and related emissions on the Electricity MMR 2021 data dashboard.

27 Annual demand variations also showed differences across MSs, reflecting local dynamics and driven by the varying presence of energy-intensive industries, or relevance of gas-fired plants for power generation or uneven COVID-19 impacts across economic sectors²³. [Figure iii in Annex 1](#) offers an overview of the share of gas in the primary energy consumption and of the YoY gas demand variation per MS.

Mid-term demand prospects

28 The future role of natural gas in the EU is intensely debated. The current high gas prices hampering economic activity, alongside with ongoing energy efficiency efforts are expected to put downward pressure on gas demand in the years to come. The International Energy Agency (IEA) foresees that European gas demand will fall by 9% in 2022. At global level, demand will also drop in 2022 (-0.5% YoY) as a result of more limited industrial consumption and gas-to-coal switching in Asia²⁴.

29 Furthermore, in order to become a carbon-neutral economy by 2050, the use of natural gas will need to drastically decrease in the coming years. Even if low-carbon and renewable gases are expected to partly substitute conventional gas consumption, gas demand is anticipated to continuously decrease due to the increasing electrification of the energy system and improved energy efficiency. Overall, the expansion of renewables and reduced space heating requirements will drive this change²⁵. Yet, the general trend to reach a net zero economy predicts phase outs of coal and nuclear power plants, which will require adding gas-fired power generation until renewable electricity generation will be the predominant source of the energy system. This is in spite of the fact that several Member States²⁶ were recently taking decisions to extend coal-fired or nuclear power generation in view of the reduced gas flows from Russia.

30 A variety of mid- and long-term scenarios have been projected with different policy assumptions. The IEA had previously estimated that EU gas demand could fall by 20% by 2030²⁷. The Russian invasion of Ukraine and the record-high gas prices are predicted to accelerate these trends. The EC's REPowerEU Plan calls for gas demand reductions of 30% and energy consumption reductions of 13% by 2030. [Section 1.2.3.4](#) offers an overview of the measures targeted to reduce the EU supply dependency on Russia, which include speeding up renewable electricity generation and EU energy system electrification. (As an illustration, more than 50 bcm of gas demand reduction - i.e. circa 10% of today's EU demand - will be achieved by 2030 by improved energy-efficiency measures in homes.)

1.1.2 Supply developments

31 The supply of gas to EU markets altered significantly during 2021 and the first half of 2022. LNG deliveries decreased from Q1 and up until Q3 2021, but rebounded from Q4 2021 to reach record-highs in Q1 and Q2 2022. Pipeline supplies remained below average in the first half of 2021 (although steady vis-à-vis the non-typical flows of 2020) and then continuously declined from the second half and across Q1 and Q2 2022, as a result of significantly reduced Russian flows. In addition, EU and UK gas production reached all ever lows. As a result, large storage withdrawals were needed to meet demand.

32 [Figure 4](#) shows that underground storages delivered much more gas in the first semester of 2021 in comparison to 2019, to offset the decreasing LNG and pipeline flows in the same period and meet the rising demand. (The year 2019 is used as a reference for comparison given the non-typical imports across the first semester of 2020.) In addition, the right part of [Figure 4](#) presents how pipeline flows dropped considerably in the second half of the year, mainly due to the Russian supply drop.

23 In 2021, final gas demand decreased in only 7 out of 27 MSs compared to 2020. However, in Q1 2022 demand fell in 23 MSs. The largest relative demand reductions were observed in MSs with large industrial sectors dependant on gas (see [Figure iii in Annex 1](#)).

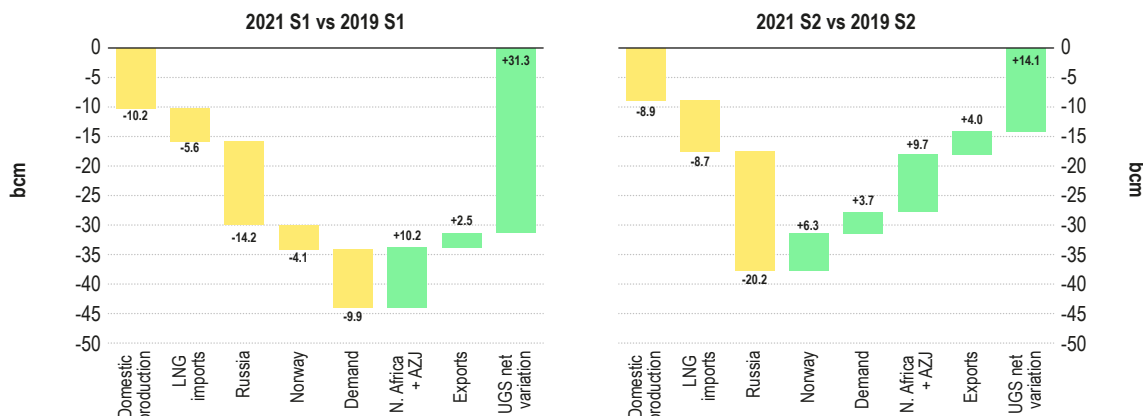
24 See [IEA Gas Quarterly Report Q3 2022](#).

25 A number of MSs and cities are announcing to cease new gas household connections for heating (e.g., Austria by 2025)

26 See [footnote 17](#).

27 See [IEA World Energy Outlook 2021](#).

Figure 4: Comparison of the changes to gas supply to the EU and UK- first and second semester of 2021 the first and second semester of 2019 – bcm/semester

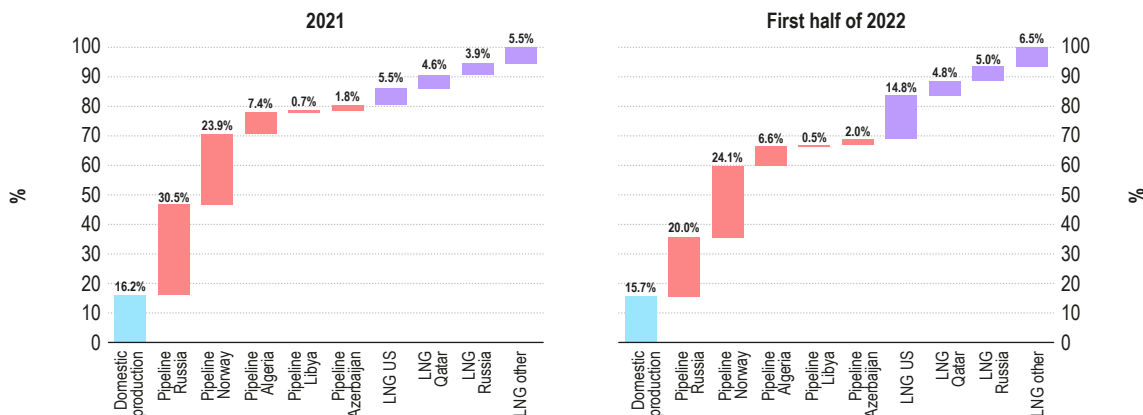


Source: ACER based on ENTSOG, Eurostat and GIE.

Note: Decreases (i.e., supply tightness) result from higher demand and/or lower supply. Increases (supply ampleness) result from lower demand and/or higher supply. *For storages, any increase in withdrawals and/or reduction in injections is an increase in supply and vice versa.

33 Figure 5 shows the EU plus UK supply portfolio in 2021 and the first half of 2022²⁸, underlining their high dependency on gas imports. Domestic production continued to decline (11% YoY) to cover only 17% of EU plus UK gas supply in 2021 (83 bcm). A lower production cap in the Netherlands and a reduction in production volumes all across the UK, Romania, Germany, Italy and Denmark explain the decrease. The annual drop occurred in spite domestic production’s moderate rise from Q4 2021, as the high gas prices and policy support changed the profitability of some domestic fields²⁹.

Figure 5: EU and UK gas supply portfolio by origin – 2021 (100% = 480 bcm, %) and first half 2022



Source: ACER calculation based on International Energy Agency, Refinitiv, ENTSOG, Gassco and Eurostat.

34 Russian pipeline supply accounted for 145 bcm in 2021 (31% of total supply). This was a 2% drop YoY, but a 19% fall in comparison to 2019. Russian supplies fell significantly since Q4 2021 (25% in Q4 2021 and 40% YoY in the first half of 2022). A number of elements account for the progressive supply drop across the year:

- a) Gazprom’s gas production was 20% higher in 2021 compared to the average of the five preceding years. However, the higher Russian domestic demand and the need to refill Russian storage sites (heavily depleted by the end of the winter 2020/2021) absorbed a significant part of that rise. Infrastructure maintenance and physical bottlenecks prevented ramping up exports into the EU. Additionally, increased sales to markets such as Turkey (10 bcm/year extra) or China (5 bcm/year) drew some gas away from European markets.

28 The data are presented together due to the strong interconnection of the systems.

29 However, the production extension at the Dutch Groningen is carefully evaluated and may only be called in as last resort to offset or partially offset the reduced Russian flows. In accordance to IEA estimates, UK and EU conventional natural gas domestic production could drop by further 20% in 2025.

- b) However, strategic and political aspects played a role too. Gazprom's tight short-term gas sales³⁰, together with the narrow gas injections into its controlled storage sites (an extended case box analysis on the subject is done in [Section 1.2.4.1](#)) were instrumental to putting an upward pressure on EU hub prices during the Winter 2021/22. That in turn pushed the prices of Gazprom's hub-indexed bilateral supply contracts up³¹. Besides, the political connotations around the approval of Nord Stream 2 were also important. Gazprom's reluctance to acquire shorter-term transmission capacity in the fall of 2021 to increase flows across alternative supply routes with spare capacity, – chiefly through Ukraine but also through Poland – was perceived to put pressure on the entry into operation of its second offshore interconnector. In this context, the Ukrainian gas incumbent Naftogaz filed a competition complaint to the EC in December 2021, accusing Gazprom of abusing its dominant position in the European gas market³².
- c) The gradual deterioration of the diplomatic relations and the economic sanctions implemented after Russia's invasion of Ukraine, aimed at reducing supply dependency on Russian energy, further contextualise the case. Even if Gazprom at first maintained its long-term supply commitments, disruptions started to take place from Q2 2022, first with cuts to Poland and Bulgaria due to their refusal to pay in rubbles, and then with the blocking of the flows across Yamal in May 2022, and later to Finland, the Netherlands and Germany (including deliveries into Danish Orsted). Those aspects are elaborated in the sections below.

35 In contrast, annual average Norwegian pipeline supply was in line with 2019 and 2020 volumes (+0.4% YoY), in spite of various pipelines being subject to delayed and unplanned maintenance in the summer of 2021. Norwegian gas flows increased in Q4 2021 and rose further in the first half of 2022 (8% YoY) assisting to alleviate EU supply tightness. Export stations and selected transport lines are operating at nameplate capacity. However, the contained rise in the face of extremely high prices indicates that the Norwegian shelf has relatively limited extra production to offer to the EU market (but also that upstream investments to extend production have been put on hold in the last year). The higher inclination of Norwegian producers to direct hub sales and to index bilateral contracts to hub-references rendered very high profits to Norwegian basin gas producers.

36 Algerian and Lybian pipeline supply rose by 66% YoY, as EU gas buyers in the Iberian Peninsula and Italy maximized the nominations of their still partly oil-indexed contracts, which became increasingly price competitive. However, North African pipeline supplies have declined by 15% YoY in the first half of 2022, due to ceasing flows across the Tarifa interconnector and lower Lybian flows. [Section 1.1.3](#) discusses this issue further. Sonatrach has ramped up its LNG production though, in part to deliver larger liquefied gas volumes to Spain after the closure of the Tarifa interconnector.

37 The Trans Adriatic Pipeline delivered increased volumes of Azerbaijani gas to the South East of Europe (8.5 bcm in 2021 and 3 bcm in Q1 2022). As [Figure 37](#) shows, Azerbaijani gas accounts for an increased share of supply in Bulgaria, Greece and Italy.

38 LNG flows into the EU and UK decreased by 25% compared to 2020, supplying 94 bcm. However, they have risen by 60% YoY across the first semester of 2022. LNG imports are being highly determined by the global competition for tight LNG resources, which is making LNG deliveries more volatile than in the past as [Section 1.2.3](#) elaborates.

39 Finally, gas exports from the EU into Ukraine fell to 2.6 bcm amidst a halting of deliveries across Q4 2021³³. On the other hand, the total transits across the Ukrainian system into the EU were down by -13% YoY, shaped by the terms of the five-year agreement signed in December 2019. Ukrainian flows into the EU further fell by 37% YoY in Q1 2022 (see expanded considerations in [Section 1.2](#)).

30 I.e., Gazprom offers direct sales to the market above the prevailing bilateral contracts; Gazprom sold 20 bcm less gas at its electronic sales platform (ESP) in 2021 compared to 2020 (all products considered). Since mid-October 2021, trading activity at ESP was discontinued. In parallel, Gazprom trading arm purchased more short-term volumes at the hubs YoY, likely to back some long-term contracts' nominations which may have resulted in increased price pressure on the hubs.

31 This represents a shift of strategy, giving priority to value rather than market share.

32 Naftogaz pointed to the reduced spot gas deliveries, the limitations in refilling its own storage facilities and the ceasing of sales through Gazprom's electronic sales platform aimed at "creating an artificial deficit of gas to pressure the EU into securing the rapid commissioning of the Nord Stream 2 pipeline without complying with European rules". The EC is currently looking into the allegations of possible anti-competitive conduct.

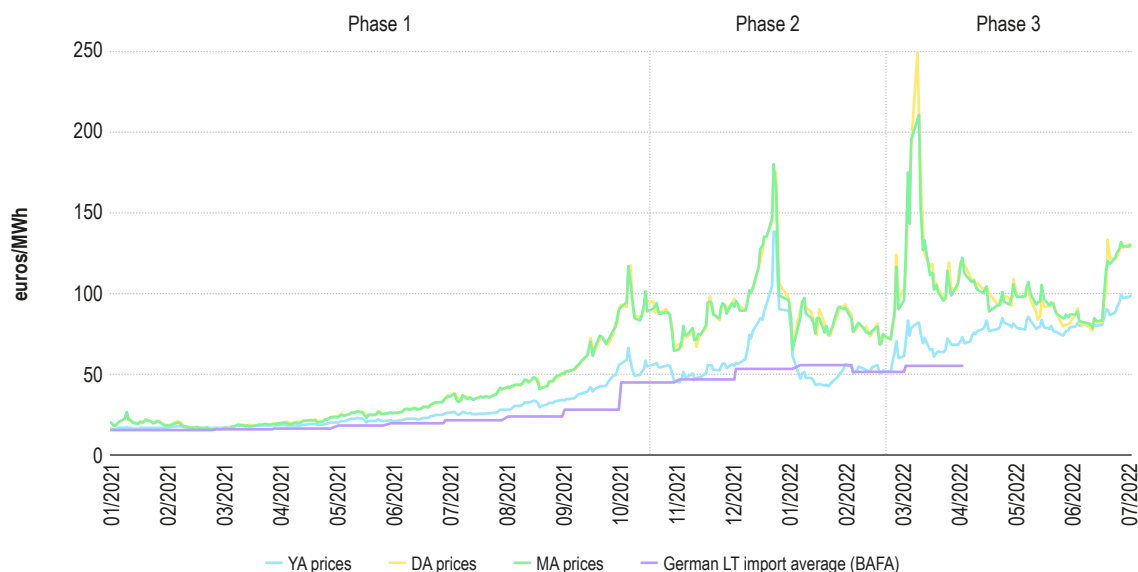
33 In accordance to the [Ukrainian TSO data](#).

1.1.3 Gas price developments

1.1.3.1 Hub prices evolution and main drivers

- 40 As outlined in the Executive Summary, a sequence of events has pushed EU gas hub prices up with high speed since mid-2021. The price surge can be split into three distinct phases – see also [Figure 1](#), with different drivers taking responsibility for each phase. Figure 6 shows that hub spot prices quadrupled from April 2021 to October 2021 (Phase I) rising from 20 to 80 euros/MWh, amid scarcer LNG imports and narrow pipeline flows, concurring with recovering gas demand. Prices reached initial record-highs in the second week of October 2021, when decreasing Russian pipeline flows and low underground storage stocks prompted supply adequacy concerns. Prices dropped to some extent in November 2021 but they strongly rebounded to new maximums in the second half of December 2021 (reaching a maximum of 180 euros/MWh), amidst uncertainty about the missing volumes of Russian supplies and strong global price competition to attract spot LNG (Phase II).
- 41 The Russian invasion of Ukraine made EU gas hub prices hit their highest point in the first week of March 2022 (spot gas reached 250 euros/MWh across selected trading sessions), with growing anxieties about a potential gas supply disruption taking place (Phase III). The EU reassessed their supply diversification options and extra LNG imports replaced Russian flows to a considerable extent. However, spot prices remained extremely high (reaching from 70 to 120 euros/MWh) even if they were below March 2022 highs. The price level, at this point, did not stem from severe physical shortages but more from perceived risks of potentially facing significant disruptions of Russian gas flows. In this context, storage filling obligations and tight LNG global supply were a relevant element driving spot prices up. Those risk perceptions materialized by the end of April 2022, when Gazprom curtailed supply to Poland and Bulgaria when the two countries remained adamant in paying their gas purchases in euros as opposed to rubles as per the Russian decree that modified previously followed contractual arrangements.
- 42 The interplay of sanctions and Russian countermeasures added additional tensions to EU gas prices across Q2 2022. In May 2022, Gazprom announced the halt of flows to Germany via the Polish section of Yamal corridor, in retaliation to international sanctions. Gazprom had halted flows to Gazprom Germania some weeks before that. Also in May, shipments to Europe via Ukraine were reduced by circa 25% after the Ukrainian TSO became unable to operate a compression station in an occupied territory. While in June Gazprom extended the halts to Shell, Orsted and GasTerra, and later lessened the flows across Nord Stream into Germany alleging technical issues, what together with an extended outage in the US Freeport LNG liquefaction terminal pushed prices again above 130 euros/MWh. Those events exerted pressure on spot prices, with market participants reconsidering their positions and hedging strategies.

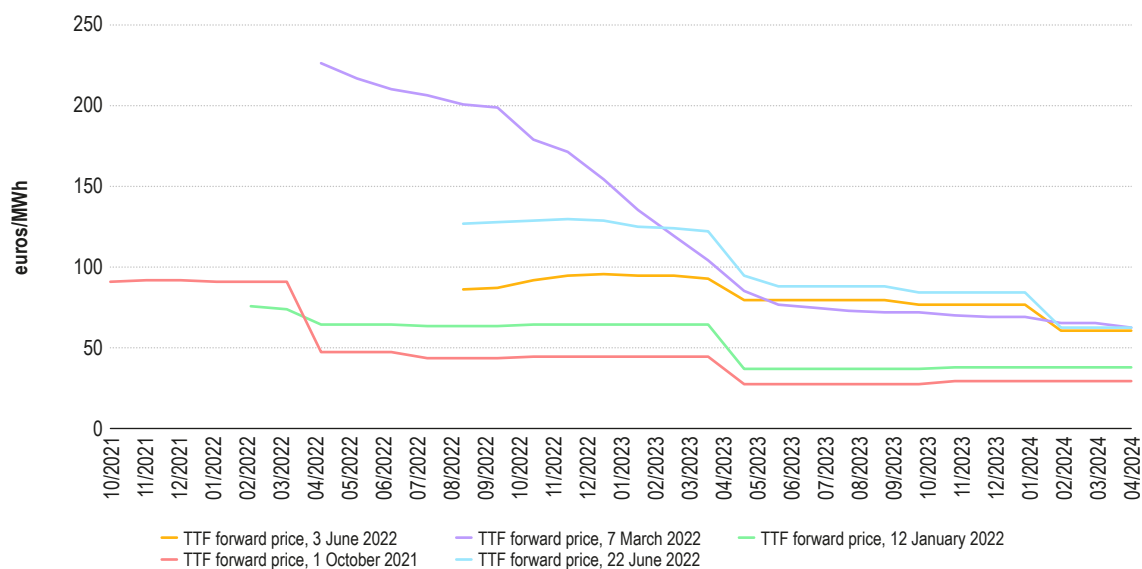
Figure 6: Evolution of TTF spot and forward hub prices and LT contracts estimates – January 2019 – June 2022 – euros/MWh



Source: ACER calculations based on GIE and ICIS Heren.

- 43 The volatility of gas hub prices also reached record-high levels³⁴. This volatility reflected sign LNG and pipeline supply prospects, weather forecasts (including renewable generation prospects) and, from autumn 2021, increased geopolitical risks.
- 44 The price rise was most marked in short-term hub products. Figure 6 shows the considerable price premium that day-ahead and month-ahead products exhibited against forward ones (i.e., year-ahead). The initial market sentiment across the summer and the fall of 2021, but subject to periodic changes, was that prices would decrease from Q2 2022 onward, once more favorable weather conditions would drive global gas consumption down, thus making more flexible gas supply (and, importantly, spot LNG) accessible at EU hubs. However, market participants had to revise those estimates as the geopolitical situation deteriorated and ended with the Russian invasion of Ukraine. Forward prices for delivery in 2022 and 2023 then reached new highs, as Figure 7 shows. As discussed in the Executive summary, this is because once having committed to minimize Russian supply over a certain timeframe, the alternative pipeline and domestic incremental supply options are deemed constrained, whilst the LNG markets are expected to remain tight subject to global competition until new production capacity may come online (a case box in Section 1.2.3.4 offers more detailed considerations).

Figure 7: Evolution of gas (TTF) forward prices comparing the contractual outlook – October 2021 – June 2022 – euros/MWh



Source: ACER based on ICIS Heren

Long-term contracts in comparison to hub prices

- 45 The prices of long-term gas supply contracts remained overall somewhat lower and flatter throughout the year than hub ones, depending on their specific price formulas and time-lagged indexations. Figure 6 has shown the German BAFA reference for long-term imports. Figure 35 offers a broader comparison, showing the prices of a variety of long-term contracts per supply origin.
- 46 The gap between spot and long-term prices opened some inquiries about the reliability of hub-pricing and as such about the validity of linking long-term contract prices to spot ones, and about how to foster hub trading activity. Some stakeholders expressed their opinion that bilateral long-term contracting (or reduced exposure on short-term procurement) would better serve to hedge volume risks and prevent episodes of volatile prices (as well as prevent certain producers or sellers from taking advantage of scarce supply conditions and moving prices up for their benefit). Considerations on the matter, similar to those already outlined in the Recommendations, can be viewed in the case box below.

34 Volatility measures how large the price swings around the mean price are. In 2021 and Q1 2022, volatility reached the highest level across the decade (e.g., spot prices' volatility more than doubled the ten-year average, rising by a factor of four in December 2021).

Hub price formation: main drivers

When scarce flexible supply led to record-high gas prices in Q4 2021 and the first half of 2022, not only hub prices but also the price of long-term supply contracts rose. This is because long-term contracts are typically, though not exclusively, linked to hub-price references (the specific price increase being dependent on time-lags and price formulas agreed to in the contract³⁵).

Hub prices tend to be set by flexible gas supply sources. Those include direct short-term hub sales of gas pipeline producers (EU domestic and Norwegian producers first opted for direct hub sales, whilst Gazprom has been gradually increasing the volumes offered at hubs. North African producers are less active hub sellers), hub sales from EU suppliers (long-term contract surpluses, storage portfolio optimization...), cross-border hub trade and spot LNG cargoes. Besides, gas demand is a key pricing element. Moreover, significant interdependencies exist between gas prices and the prices of other energy commodities such as power, coal or carbon emissions, especially considering the competition between gas and coal-fired power generators. The prices of distinct hub products (i.e., per duration) are influenced by the way shippers and traders are looking for portfolio optimization opportunities.

In the past five to seven years, ample flexible supply had led to a period of relatively low EU hub prices. Prices fell to their lowest point in Q2 2020, amid COVID-19 effects on demand coupling with record LNG availability. However, in 2021, flexible volumes decreased mainly due to decreased LNG spot deliveries (moving to Asian premium markets), tapering gas hub direct sales from local and Russian producers (dropping EU domestic production, plus Gazprom's changed behavior) and lower surpluses from long-term supply contracts offered by EU suppliers (given their reduced surpluses, but also given to the higher price bids due to growing opportunity costs).

In essence, the increase in hub prices was notably related to the reduced gas volumes under direct control of EU companies. A partial gradual abandonment of long-term supply contracts by EU buyers has been taking place in last years, driven by the experience and expectation that gas volumes hitherto delivered under those contracts would instead be available at gas hubs, whilst hubs better enabled shippers to adjust their supply portfolios, overall ending up with prices and payments being generally lower. However, that was not the case in 2021 and the first half of 2022, in a very tight market, where the marginal price setters of hubs become more expensive.

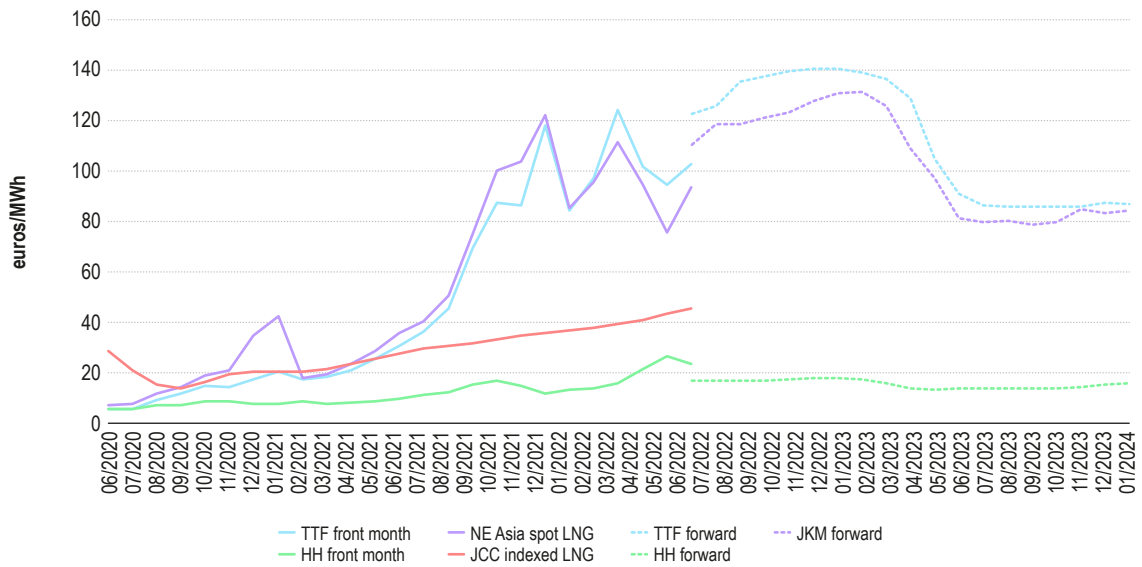
1.1.3.2 Global price developments and price correlation with other energy commodities

- 47 The events across 2021 proved how EU gas prices are increasingly driven by global supply and demand equilibriums, with spot LNG acting as the key vector to match regional demand with global supply.
- 48 On the one hand, North Asian and South-American (spot) markets maintained a strong price correlation with the EU and hence reached record prices as well. This was an outcome of the competition for LNG resources and inter-regional hub hedging. However, Asian, Indian, and South American end consumers still mainly rely on long-term oil-indexed bilateral gas contracts. This has decreased their price exposure on average lower than that at EU markets³⁶ (see Japan Crude Cocktail JCC – price index in [Figure 8](#). Further consideration about dominant pricing mechanism in the individual regional markets are discussed in the case box under [Section 1.2.3](#)). On the other hand, the US producers took advantage of their cheaper and massive domestic production, which reached record-high levels at the end of 2021. While Henry Hub prices also rose considerably (90% YoY for the annual average), they remained at much lower level as shown in [Figure 8](#). The figure also discusses the forward price estimates in the month of June 2022.

35 Month-ahead hub products tend to be increasingly more the dominant reference, but they are combined with other hub products of diverse duration, as well as mixed indexations to other commodities and economic parameters.

36 See more estimates about gas regional prices in the [IEA Quarterly Report 2022](#).

Figure 8: Evolution of regional gas prices – June 2020 – June 2022 – euros/MWh



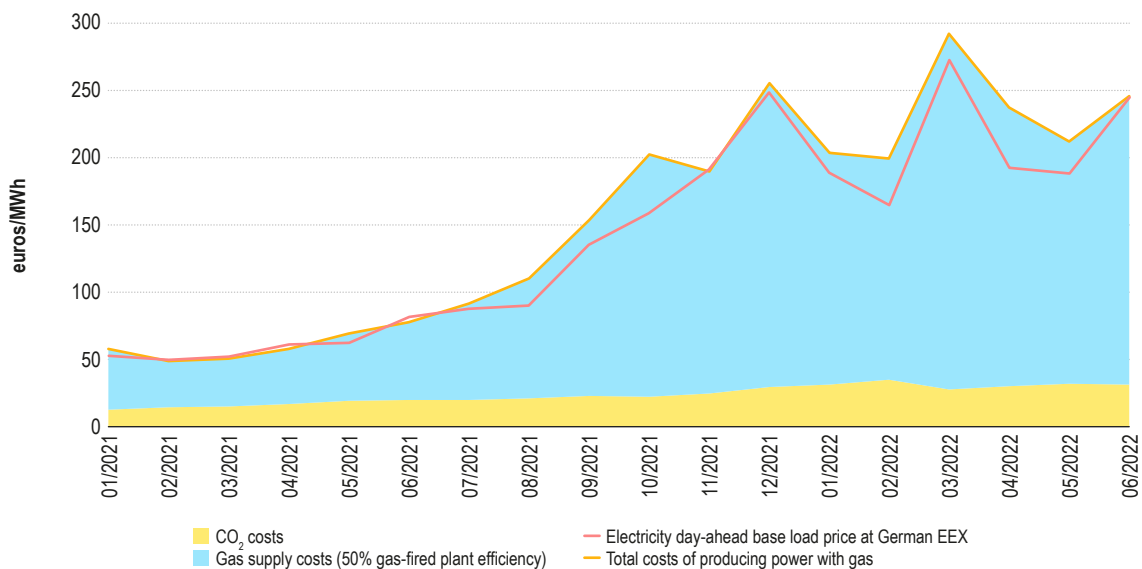
Source: ACER based on ICIS Heren in June 2022.

Gas price correlation with other energy commodities

49 The correlation of gas prices with other energy commodity prices was also significant:

- Electricity prices also reached record-highs, climbing by more than 200% from Q1 to Q4 2021. The increase was mainly driven by the rise in gas-fired power generation costs, as gas units tend to set the marginal price reference in most EU pay-as-clear power markets³⁷. Figure 9 illustrates that correlation for the German market, also proving how the parallel growth in carbon emission costs further amplified the rise in electricity prices (although carbon emissions accounted for a lower share of the total increase).

Figure 9: Evolution of gas-fired plants power generation costs and power prices in Germany – 2021 – June 2022 – euros/MWh



Source: ACER calculations based on ICIS Heren.

37 Gas-fired plants often set marginal electricity prices in EU power markets. When hydro plants act as price-setting units instead, they optimise their annual production and thereby tend to relate their opportunity cost to the costs of generating electricity with gas.

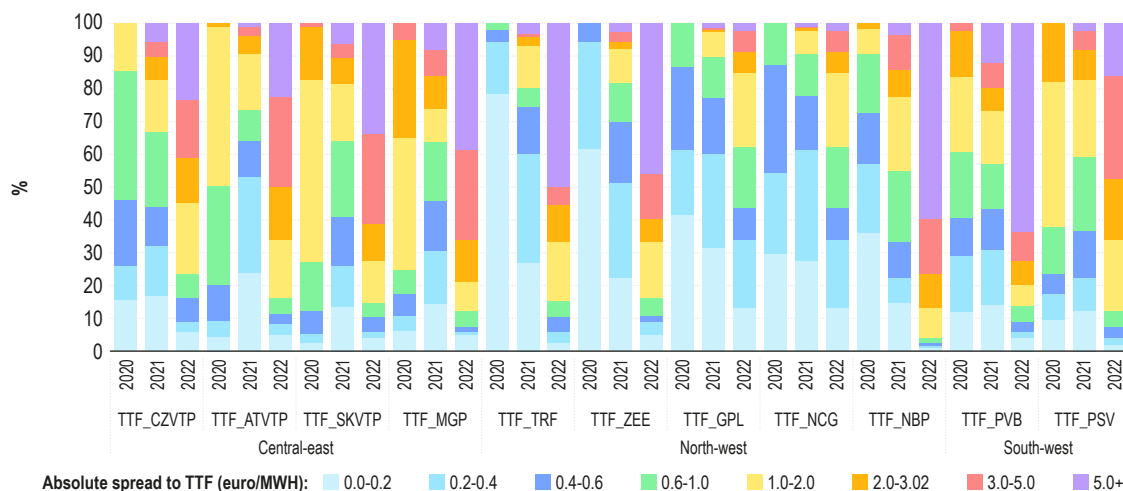
- Coal and gas prices, kept heavily interdependent, competing to set power marginal prices across the EU. Carbon emission prices act as a balancing factor in that competition. The soaring prices of carbon emission allowances (EUAs climbed from 30 euros/tonne in January 2021 to 80 euros/tonne in January 2022), together with high international coal prices, reduced the profitability of coal-fired generation until end Q2 2021. However, the rapid gas price climb made gas-fired generation less profitable than coal-fired generation from summer 2021 onwards. Moreover, the production of coal in China and India increased in the second half of 2021 to prevent power supply scarcity. That led to reductions in global coal prices and made clean dark spreads (i.e., coal-fired power plants' margins) highly profitable from Q4 2021 in contrast to clean spark spreads (i.e., gas-fired power plants' margins) being at very low levels. Coal profitability has worsened again from mid-summer 2022, following the introduction of an EU ban on Russian coal imports (Russian hard coal made up to 50% of EU imports in 2021). The ACER MMR electricity dashboard offers an overview of the relative competitiveness of both generation technologies, as well as their power generation shares³⁸.
- The correlation between oil and gas prices kept weakening, as oil gradually loses ground in gas supply contracts' indexations. Brent oil prices rose by up to 70% across 2021 (a significant yet minor relative rise) whilst reaching new record highs in Q1 2022. The loosening COVID-19- restrictions and the recovery in economic activity made global oil demand rise faster than supply, with the latter being constrained by restrictions in production (from late 2020 and throughout 2021, OPEC+ limited production increases in order to keep prices higher). Furthermore, global oil production was kept modest after the invasion of Ukraine despite the calls to increase it, moving global oil prices to new highs and despite the IEA members collectively released twice their strategic oil stocks in the course of spring 2022.

1.1.4 Hub price convergence

50 The extraordinarily high price levels experienced on EU gas markets did not imply a severely worsening price alignment between MS's gas hubs during 2021. Prices were close on annual average. Even so, the record price volatility and some variant market fundamentals pushed hub price differences slightly higher than in 2019 and 2020³⁹. However, record-high hub price differences came to fore in Q1 2022, and, significantly, from late-April 2022, as a result of much higher LNG deliveries into selected coastal European markets along with cross-border interconnection capacity constraints.

51 Figure 10 compares the evolution of price convergence between a selection of hub pairs in 2021 and Q1 2022, analysing the number of days when the day-ahead product price gap vis-à-vis the Dutch TTF hub benchmark stayed within predefined ranges.

Figure 10: Day-ahead price convergence between TTF and selected EU hubs – 2020 – June 2022 – % of trading days within given price spread range



Source: ACER calculations based on ICIS Heren and national exchanges.

38 Coal-fired power generation increased by 36% YoY in the EU 2021, while gas-fired generation fell by 8%. Gas-fired generation was still higher than the 2017-2020 average, while coal was 30% below as a result of the substantial decommissioning of coal-fired power units in the past years. In contrast, China alone is developing more new coal-fired generation plants than the EU and US are closing combined.

39 In 2020, the lower demand caused by COVID-19, combined with ample LNG deliveries and high UGS stocks brought an excess of supply that considerably smoothed regional price spreads.

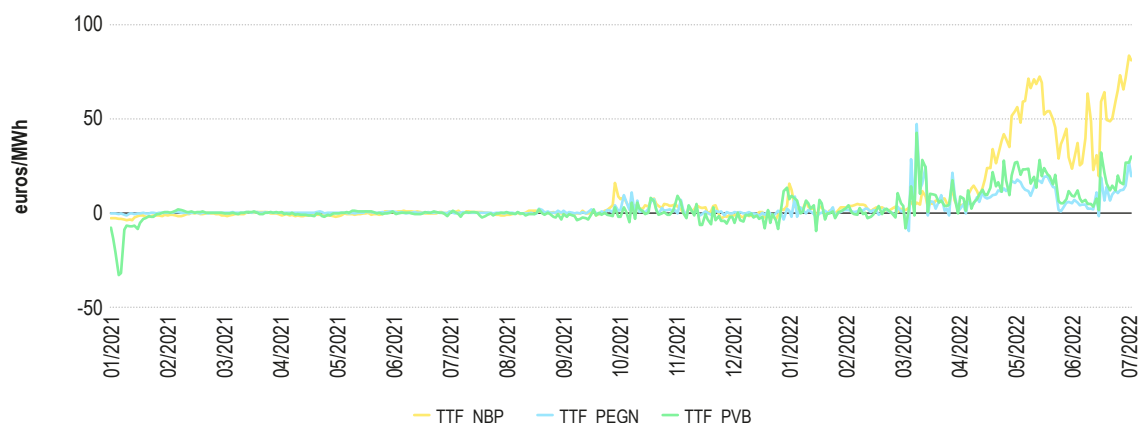
- 52 Across 2021, price convergence and price correlation remained the highest across North-West Europe, where price differences remained well below 1 euro/MWh for most trading seasons. This means that prices were hovering but still frequently below cross-border transportation costs. Strong convergence was maintained by then in spite of the expiration of some historical long-term supply contracts (but also despite the lower surpluses at prevailing ones⁴⁰). Flexible North Sea supplies sold at quite similar prices for all regional hubs was a key factor that kept prices close.
- 53 Interestingly the prices of the most liquid EU hub TTF, were less often the cheapest option in 2021 than in past years, something that became more evident across 2022. The falling Dutch domestic production and the rising imports into the Netherlands have contributed to that shift. For example, the French TRF hub frequently traded at a discount, likely assisted by higher gas stocks in French UGSs and the capability to attract more LNG. The Italian PSV hub also visibly improved its convergence and traded at a discount to the Dutch TTF over multiple sessions on similar grounds, likely also benefitting from competitive prices agreed to in bilateral contracts. As an illustration, flows from northwest Europe into Italy via the Northern Transitgas pipeline dropped compared to previous years following the start of the TAP corridor, which will be further discussed in [Section 1.2.1](#).
- 54 Price convergence tends to be stronger between adjacent pairs of hubs within the same region. This is due to their closer market fundamentals as well as shorter transportation distances (and hence lower transportation tariffs). Central and South Eastern hubs, as well as Mediterranean and Baltic ones, showed, on average, higher absolute price than NWE hubs across 2021, although that incidence is changing and is less marked in 2021 than in past years. Overall, the different supply portfolios and structural and competition aspects of the individual hubs (LNG supply gaining relevance as of late), the cross-border capacity availability (or constraints), the prices resulting from prevailing long-term contracts (which may later nurture hub trading activity) and the specific interplay of marginal supply and market opportunity pricing drove prices up and down across different periods for these hub pairs.
- 55 As mentioned, in Q1 2022 and markedly from April 2022, the traditional price convergence and correlation levels among EU hubs noticeably changed. The shift away from Russian pipeline supply to increased LNG imports, some cross-border interconnection capacity constraints of flowing gas from west to east⁴¹ together with limited LNG regasification capacity in Northern Europe were the driving factors of divergence. The larger regasification capacity – and hence LNG volumes – in Spain, France and the UK (and related to it, at Zeebrugge linked to the Belgian hub)⁴², brought significant spot price discounts vis-à-vis the rest of NWE hubs, as [Figure 11](#) shows. Although the spreads for forward products are of a lower magnitude (from 5 to 10 euros/MWh in June 2022 for year-ahead products); coastal markets will keep benefitting from lower prices for some time, until capacity constraints on the west-east flow direction and LNG terminals' usage is optimised or new LNG developments are concluded in the coming months or year.

40 The long-term over-contracting by EU mid-streamers had originated in recent years a mismatch between some of their historical long-term contracted volumes and actual demand needs. This surplus often turned into sunk costs for companies, and when they were confronted with this situation, they increased their hub trading, placing bids around the short-run marginal costs (SRMCs) for hub-to-hub gas transportation. Given that SRMCs accounted for only a fraction of transportation costs, the practice favoured price convergence, with hub spreads frequently falling below cross-border fees. The expiry of surplus LTCs started to limit SRMC bidding.

41 This includes interconnection capacity constraints (i.e. at VIP Pyrenees, BBL and IUK, France-German interconnection) which limited the amount of LNG flows from those markets into Continental Europe. Those lines were operated at maximum level, causing hubs to decouple largely above transportation costs. It can also be explained, to some extent, but the difficulties faced by market participants to book interconnection (quarterly, monthly) capacity at several IPs, due to allocation rules and algorithms.

42 The maintenance on the offshore interconnector from Norway into Germany made Norwegian flows to divert into UK contributing to the downward price pressure.

Figure 11: Day-ahead price spread between TTF and NBP, TRF and PVB hubs – 2021 June 2022 – euros/MWh



Source: ACER calculations based on ICIS Heren. .

1.1.5 Long-term supply contract developments

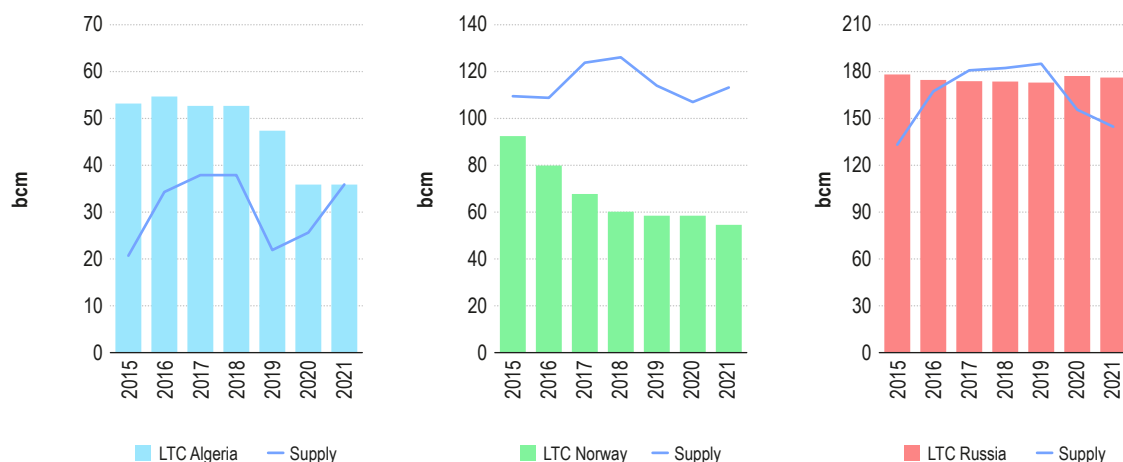
56 This section explores the rationale of long-term gas supply contracts, and investigates the volumes contracted under these contractual mechanisms up to the end of 2021. Complementarily the related case box on page 18 discusses how market developments in 2021 have led to some calls for more long-term supply contracting, while the case box on page 55 discusses how MSs – individually and/or involving the EC via a common EU energy platform – are exploring the signing of new long-term supply agreements.

Long-term contracts evolving rationale and conditions

57 As gas markets in Europe matured over the past decades, the rationale for gas buyers and sellers to enter into long-term gas supply contracts evolved. As a result, the volumes contracted long-term gradually decreased on average. Similarly, the terms of most of the prevailing and new long-term contracts evolved, with changes to their pricing and flexibility being the most significant changes.

58 Historically, long-term gas supply contracts required price and volume certainty for the producers to invest in gas fields and for the TSOs to invest in pipelines and other necessary gas infrastructure. However, where infrastructure was built and gas trading hubs became sufficiently mature, some producers and buyers abandoned parts of their bilateral long-term contracting and instead took advantage of spot and forward hub trading to better optimise their gas procurement. This has been mostly the case for North Sea producers and buyers in NWE, as demonstrated by the significant gap between volumes contracted via LTCs and actual gas supply from Norway. An overview of the EU main pipeline suppliers LTC volume compared with their actual deliveries can be seen in [Figure 12](#).

Figure 12: Estimated nominal LTC volume compared to total supply from upstream source - 2015 – 2021 – bcm/year



Source: ACER assessment based on ICIS, Eurostat, Entso-g, Gassco.

Note: Higher nominal LTC volumes than actual annual supply (e.g., as is the case for Algerian supply) would be explained by the flexibilities offered for LTC's nomination in the contracts underpinned by the take-or-pay and carry-forward clauses.

- 59 The ongoing gas market liberalization had an impact on the pricing of long-term supply contracts, which underwent significant changes. Most EU buyers exerted pressure on suppliers and renegotiated the LTC price formulas⁴³. The main aim of buyers was to change the price indexation of their contracts from oil-based pricing to gas hub-based prices and to be granted greater volume flexibility (i.e., chiefly the possibility to more flexibly nominate volumes, on both daily and aggregated annual basis, but also to reduce the take-or-pay commitments and increase the carry-forward ones⁴⁴). According to the International Gas Union⁴⁵, the share of gas imports linked to hub-price was roughly 80% in 2021, which is about three times higher compared to what it was in 2010. There are still relevant differences among regions and suppliers but hub-linked price has become the general norm not only in hub-trading but also for the long-term supply contracts.
- 60 ACER estimates that the changes to the price indexation of LTCs, together with the increase of direct gas origination at organised hubs, had rendered annual benefits in the order of 5 to 7 billion euros per year to EU consumers across the last decade. The IEA has similar considerations⁴⁶. The estimated benefits compare the actual prices at which EU buyers sourced gas against the prices that they would have paid if the terms of the historical oil-indexed contracts hadn't been revised. Figure 13 offers a comparison of selected gas supply price references since 2010.

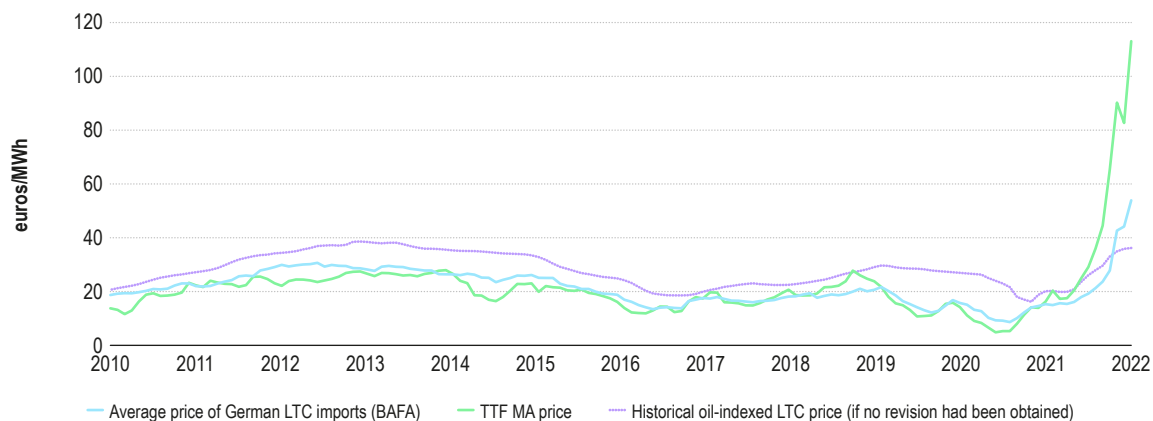
43 LTC renegotiations were prompted by the combined effect of regulatory and market factors. A background of falling demand coupled with the rising presence of price-competitive coal and renewable electricity in EU power generation mixes put pressure on the business case of long-term gas buyers. Altogether, maintaining LTC profitability was made more difficult. Furthermore, enriched supply side-competition – largely prompted by increases in LNG flexible supplies and new infrastructure developments – as well as various antitrust cases aided the revision of the aforementioned contractual conditions.

44 Flexibility negotiations also involved reducing the penalties of not meeting nominations, adjustment to the volumes that can be nominated in accordance, for example, to weather-driven demand but also in accordance to the relative prices of hubs or the agreement on rebates (i.e., price discounts if the buyers nominate more gas than nominally agreed).

45 See [IGU global wholesale gas price survey 2021](#).

46 See [IEA market commentary](#): 'Despite short-term pain, the EU's liberalised gas markets have brought long-term financial gains.'

Figure 13: Evolution of selected gas supply price references in the EU, 2010 – June 2022 – euros/MWh



Source: ACER estimations based on Refinitiv, BAFA, and ICIS Heren.

Note: The graph illustrates the delta between the virtual price of modelled historical oil-indexed LTCs (dotted line) and the actual price of revised LTCs prices (BAFA) and hub prices (TTF).

61 However, since mid-2021 EU natural gas hub-price indices increased much more than oil price indices. Thus, the price of oil-indexed gas long-term contracts became significantly cheaper than hub-priced gas supply. Hence, most of the EU LTCs became more expensive over the year due to their revised indexation. As a result, the welfare gains achieved from the revisions of LTCs into hub-indices have been offset and turned negative. This fact has raised calls from some quarters for a greater use of long-term gas contracting including the review of their pricing⁴⁷. Moreover, the supply anxiety witnessed since Q4 2021 and the growing political agreement to shift away from Russian gas in the coming years has restarted some debates about long-term contracts and their capability to commercially lock-in supply volumes, which will be further elaborated in [Section 1.2.3.4](#).

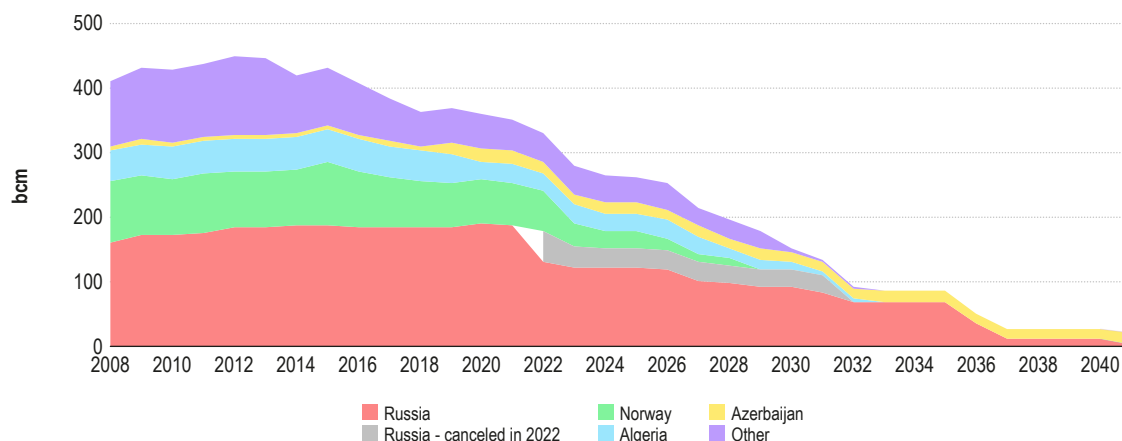
Long-term contracts overview

62 [Figure 14](#) offers a general overview of the nominal capacity of long-term pipeline gas supply contracts in place in the EU in 2021. The gathered data shows that pipeline long-term contracts with a delivery point in the EU result in circa 290 bcm of gas per year. LNG long-term contracts would cover for approximately an extra 70 bcm. Together they will represent approximately 80% of EU gas demand.

63 The main share of the LTC pipeline contracts corresponds to sales by Gazprom, which underlines the central role Russian gas supply has had in the EU gas market. Many of those contracts were subscribed across the early years of the 21st century, when direct hub sourcing was not an option. The price formulas of Gazprom's long-term contracts were revised later than the Norwegian LTCs. The EC competition case was instrumental to that end in Central East MSs, but today increasingly more contracts also include hub-price clauses. Norwegian suppliers together represent the second largest block of LTC volumes, although the higher inclination to direct hub sales of Norwegian suppliers reveals a faster expiration curve.

47 Some market participants have advocated to reintroduce some oil-price linkages in gas LTCs, but also other alternatives such as US Henry Hub, or electricity price references, as well as long-term hub product prices to smooth out price volatility.

Figure 14: Evolution of the nominal capacity of long-term pipeline supply contracts prevailing in the EU and expiration calendar – 2006 – 2040 – bcm/year



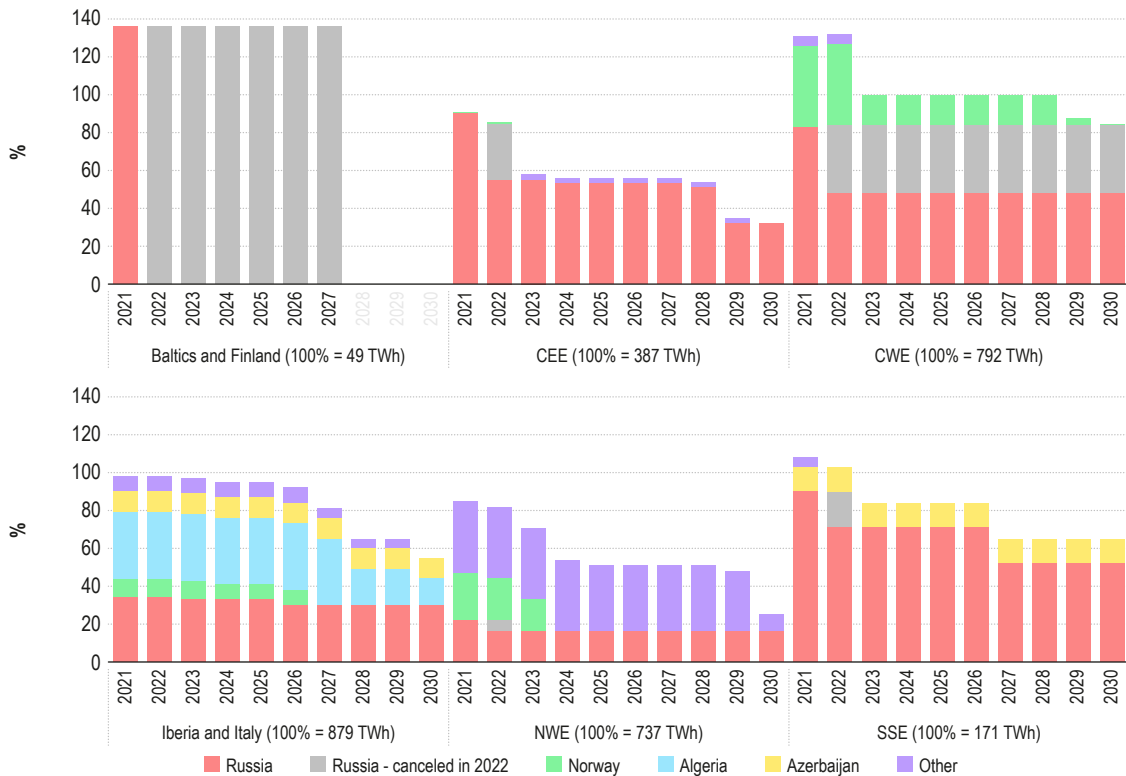
Source: ACER estimations based on Cedigaz

Note: 'Other' category includes the Netherlands, the UK, Libya or Denmark and a few others. 'Russian canceled in 2022' series refer to the contracts halted in 2022, following the negative of EU buyers to pay in rubbles and counter sanctions.

- 64 Regarding their expiration calendar, the assessed LTCs have an end term in 2045. That does not preclude new contracts being signed in the coming years⁴⁸. Moreover, the prevalence and significance of Gazprom contracts is to be seen after MSs have expressed the political aim to shift away from Russian supply by 2027 at the latest. The EC proposed in December 2021, in its Hydrogen and Decarbonised Gas Market Package, that long-term contracts for unabated fossil natural gas should not be extended beyond 2049 to facilitate the penetration of decarbonised gases and create a structurally more flexible gas portfolio, moving away from unabated natural gas.
- 65 Looking at regional MS level, Figure 15 offers an overview of long-term contracts reported for delivery for a sample of MSs, whilst contrasting them against the annual demand of the same MSs. The comparison is used as a proxy to estimate the prevailing significance of bilateral supply contracts across different jurisdictions across different EU regions. The analysis should be taken with a caveat though, as the bilateral contracts' volumes delivered to a given jurisdiction may not necessarily meet the demand in that market or it could be larger and transferred across several national jurisdictions.

48 For example, Hungary signed a 15-year LTC agreement of 4.5 bcm/year with Gazprom in September 2021.

Figure 15: Origin and evolution of the nominal capacity of long-term pipeline supply contracts – 2021 – 2030; 100% = 2021 demand

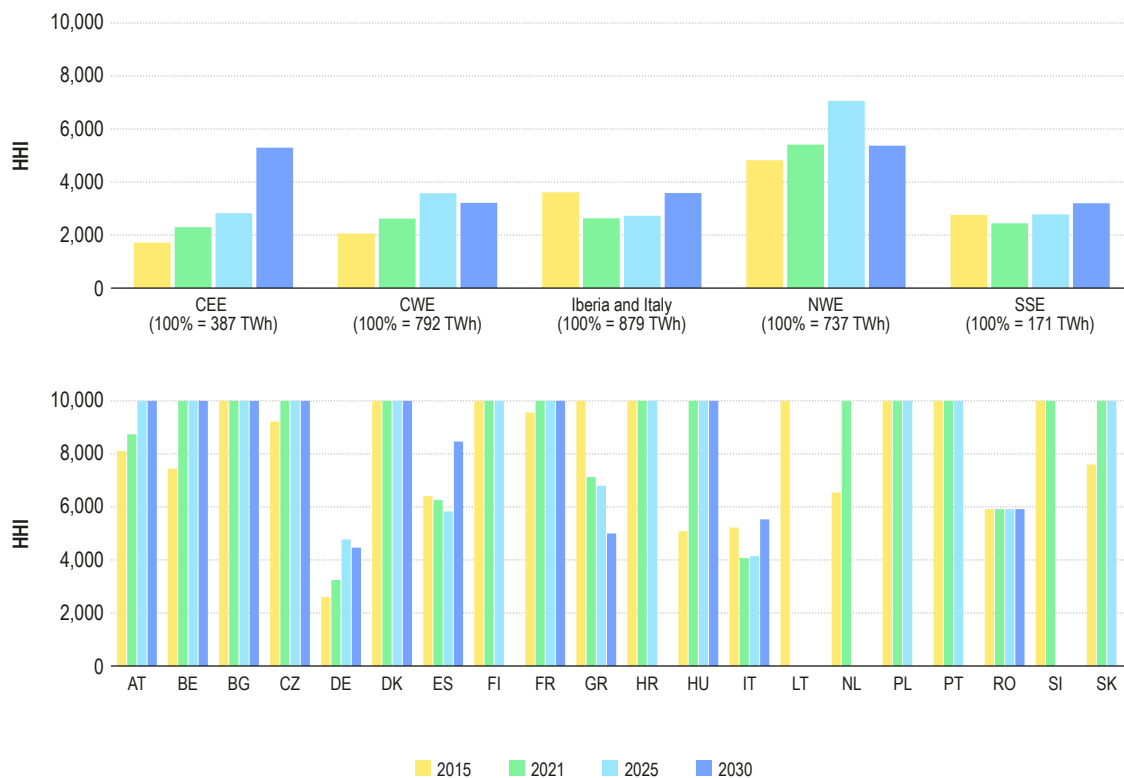


Source: ACER estimations based on Cedigaz and NRAs

Note: Baltics and Finland include LT, LV, EE and FI; CEE includes AT, HR, HU, PL, SI and SK; CWE includes DE, DK and CZ; Iberia includes ES, IT and PT; NWE includes BE, FR, LU and NL; SSE includes BG, GR and RO.

- 66 Central and South European MSs show a higher proportion of demand covered by long-term contracts. Greater reliance on long-term supply tends to inversely correlate with the direct hub procurement and hub trading activity. Assessments on the matter are further developed in [Chapter 2](#).
- 67 From the EU buyers' perspective, the concentration of long-term pipeline supply contracts is high. In most MSs, long-term pipeline contracts are solely subscribed by national incumbents in view of the historical role that they played for the development of the gas markets and the complexities that their negotiation entail. [Figure 16](#) assesses the buyer-side concentration making use of the Herfindahl-Hirschman Index (HHI). The analysis is presented first per region and after that per individual MS.

Figure 16: Overview of the buyer-side concentration of long-term pipeline supply contracts per MS and per region – 2015 – 2030 – HHI index



Source: ACER estimations based on Cedigaz and NRAs

Note. HHI is a measure of market concentration. It is calculated by squaring the market share of each firm competing in a market and then summing the resulting numbers. It can range from close to zero to 10,000.

68 While Figure 16 results offer an indication of structural supply competition at EU gas wholesale markets, the picture is only partial. On the one hand, long-term supply contracts for LNG may have been subscribed by alternative buyers. On the other hand, numerous competing companies procure gas at organised trading hubs, making use of supply contracts of shorter-duration. As Figure 47 analyses, the buying side concentration of forward products at EU gas hubs is significantly lower than that for long-term pipeline contracts analysed in Figure 16. That further underlines the role of organised trading hubs to promote supply competition.

69 Finally, long-term supply contracts tend to be backed by corresponding long-term capacity bookings that underline the right to flow the long-term procured gas through the system. The analyses about the expiration calendar of long-term capacity contracts - in relation of long-term supply ones - are offered in Chapter 3.

1.2 Infrastructure and system operation developments

70 This section reviews the main gas flow and infrastructure developments that occurred during the year and also includes an assessment of LNG and UGS market developments.

1.2.1 Physical gas flows across EU borders

Exposure to Russian gas halts

71 As introduced in the Executive Summary, the widely interconnected EU gas systems kept accommodating flows in response to price signals in the context of record high prices and sizeable supply rebalances occurring across 2021 and the first half of 2022. However, the usual gas supply security margins were more limited as a result of the reduced Russian pipeline supply and the lower storage stock levels. Hence, emergency plans and common risk assessments have become very important as the case box below underlines⁴⁹.

ENTSOG's Summer Supply Outlook 2022: short-term supply risk assessment

The European Network of Gas Transmission System Operators (ENTSOG) has a mandate to assess the prospects of gas supply, demand and flows over physical gas infrastructure before the start of each summer and winter⁵⁰. The [Summer Supply Outlook 2022](#) covers the forthcoming summer injection season, which will be key to refilling depleted underground storages. Given the exceptional circumstances, this year's Outlook focuses on the European dependence on Russian supply.

Despite of the historically low stock levels observed at the beginning of winter 2021/2022, EU storages finished the winter season at 26% of their average capacity in April 2022. Although this was below the previous six-year average, it was within the six-year range, as seen in [Figure 23](#). By end-June storage sites are filled by more than 55% on EU average. However, the continued reduction of Russian flows create uncertainties about supply adequacy, particularly in case of a larger disruption. With this scenario as a starting point, the ENTSOG assessment investigated three scenarios:

- 1) The baseline scenario concludes that European gas infrastructure offers sufficient flexibility to reach a 90% UGS stock level by the end of the summer 2022, contingent upon a minimum 20% Russian EU supply share and upheld high-LNG deliveries.
- 2) The second scenario considers disruption of Russian supply through Belarus and Ukraine from April 2022. Europe would only reach 84% UGS stock level overall. Western European countries would attract increased flows but there will be some capacity constraints to move gas eastwards; a few MSs would need to rely on storage withdrawals to meet summer demand.
- 3) The third scenario considers full disruption of Russian supply from April 2022. Europe would only reach 45% stock level overall, with significant differences amongst MSs. Western European countries would likely meet 90-100% UGS stock level, while selected Eastern European countries would likely meet 5-35% stock level. More MSs would rely on storage withdrawals to satisfy summer demand. Cross-border flows will reach limits in both North-Western and Southern Europe, while risks of demand curtailment arise in North-Eastern MSs.

All in all, the Outlook concludes that the rapid implementation of additional LNG import and cross-border capacities in Europe and enhanced cooperation amongst MSs' TSOs, reverse flow from France to Germany (conditional on the acceptability of odourised gas) and/or alternative supply sources such as from Turkey to Bulgaria can reduce Russian gas dependency and mitigate the potential effects of a supply disruption.

49 The [Gas Coordination Group](#), which brings together Member States and gas sector stakeholders across the EU, plays a key role in coordinating plans promoting supply solidarity arrangements. ENTSOG also plays a central role, issuing [EU-wide simulations of supply and infrastructure](#) and the [ENTSOG Winter and Summer supply Outlook](#).

50 Per Art.8(3)(f) of [Regulation \(EC\) 715/2009](#), it should be noted that the assessment focuses on the readiness of gas infrastructure, while it does not model market developments, such as prices, in detail.

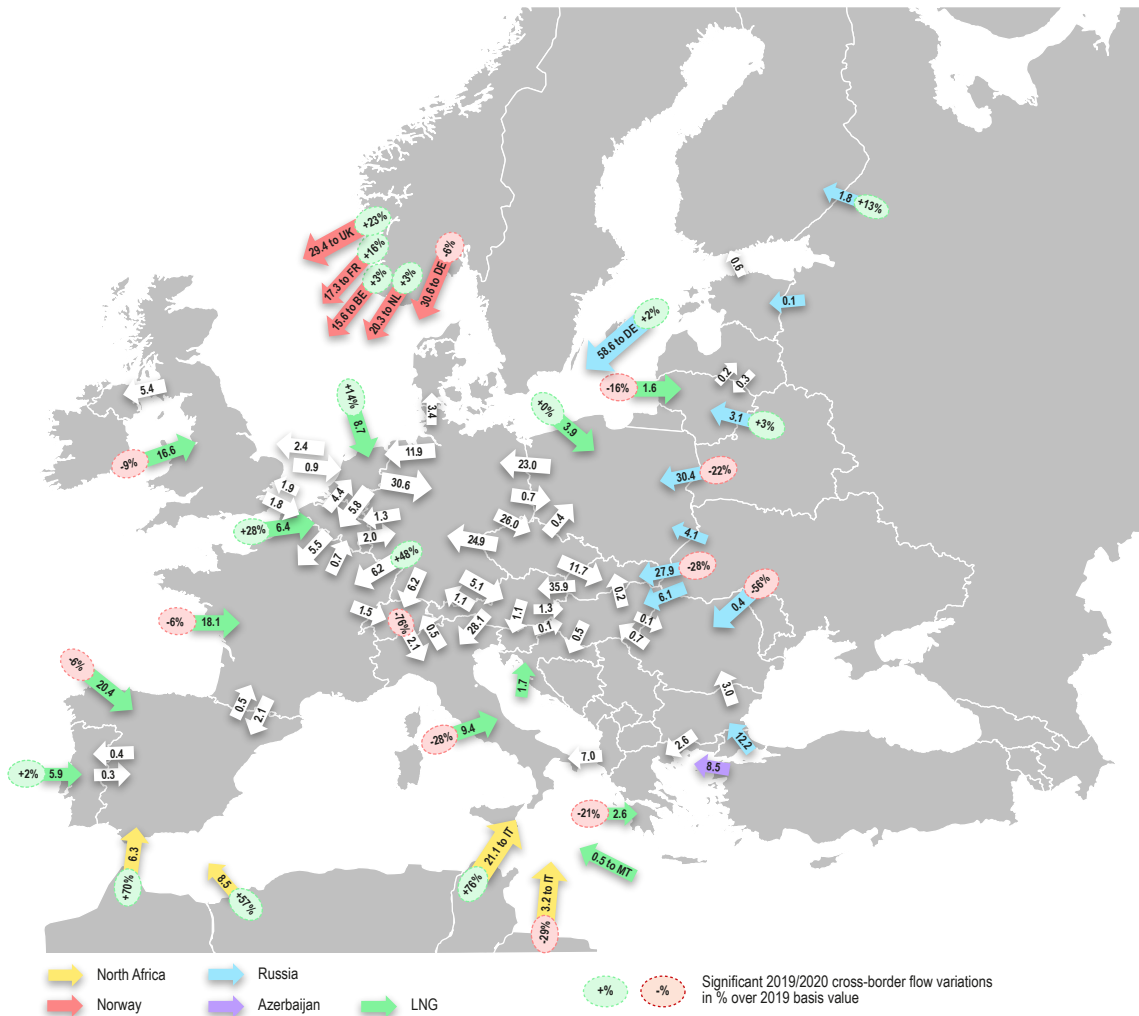
- 72 There is a rising anxiety about the continuation of Russian flows and, in case of ceased supply, about their influence on EU economies. As noted, Russian flows were cut for Poland and Bulgaria in late-April 2022 under the pretext of not meeting the payments of their current contracts in roubles. The nominal capacities of their long-term supply contracts – which were to expire in 2022 – account to 10 bcm/year and 2.9 bcm/year respectively. Supplies to Poland and Bulgaria have so far been guaranteed using storage stocks and rerouting gas flows from neighbouring MSs (partly of Russian origin), as well as by rising LNG imports. In the case of Poland via the Polish Świnoujście LNG terminal, but also from the FSRU Klaipeda and across GIPL interconnector, and in the case of Bulgaria with plans to import more LNG from Greece but also Turkey. In May 2022, Gazprom deliveries to Finland were also interrupted⁵¹, while in June 2022, Gazprom also halted supply to the Netherlands (GasTerra held a contract of 2 bcm/year until October 2022) and to the Danish midstream company Orsted (1.8 bcm/year contract with delivery in Germany due to expire in 2030) due as well to disagreements in payment conditions.
- 73 The EU sanctions and Russian countermeasures has been adding additional tensions to the market in Q2 2022. In May 2022, Gazprom announced the stoppage of flows to Germany via the Polish Yamal corridor, in retaliation for sanctions. Gazprom had specifically halted flows to Gazprom Germania and its subsidiaries some weeks before, after the company was put under conservatorship of BNetzA following an unannounced change on its ownership that did not comply with the German trade laws. In mid-June 2022, flows into Germany across Nord Stream 1 also fell (the offshore interconnector operated at 40% of its capacity). Gazprom alleged technical issues in the compression equipment together with export sanctions from the manufacturer. However market analysts as well as the German government interpreted that the decision was rather driven by retaliation motives. In May 2022, shipments to Europe via Ukraine reduced by circa 25% after the Ukrainian TSO became unable to operate a compression station in Ukrainian territory that was occupied by Russian forces. This exerted pressure on spot prices, with market participants reconsidering their positions and hedging strategies.
- 74 The decrease in Russian flows and the higher reliance on LNG to counterbalance the decreased Russian flows has demonstrated some network capacity constraints. A significant structural shift in flow patterns has been occurring throughout 2022. LNG regasified at West import terminals (UK, Iberia, France, Belgium) has been reaching countries facing reduced Russian flows, mostly in the East. However, network capacity restrictions have resulted in rising price spreads between markets as [Section 1.1.4](#) outlines.
- 75 Those network transmission capacity limitations arise from the historical design of the EU gas system, which has predominantly accommodated flows from East to West. As the EU system becomes increasingly independent from Russian supply and more reliant on LNG and alternative pipeline supplies, gas flows need to substantially reroute. This requires reassessment of system operation and available capacity combined with targeted infrastructure investment and capacity optimisation strategies, including dynamic recalculation of capacity.

Gas cross-border flows overview

- 76 [Figure 17](#) offers an overview of the EU cross-border flows across adjacent markets in 2021 identifying relevant YoY changes. Most of the identified changes have further amplified in the first half of 2022 ([Figure v](#) in [Annex 1](#) offers a synopsis of the changes across the first half of 2022).

51 Finland imported 1.6 bcm from Russia in 2021, 70% of its gas demand, but flows have halved in 2022 in view of the rising import from the Baltic Connector. Finland is expected to pivot towards LNG imports, with the new Hamina terminal expected to enter in operation in October 2022.

Figure 17: EU and EnC cross-border gas flows – 2021 – bcm/year and % of variation



Source: ACER calculation based on IEA and ENTSOG (2021).

Note: The domestic production of MSs is not included. The reported Norwegian flows into Denmark originate from offshore fields that are connected to the Danish system. The flows into and from Ukraine correspond to nominations received by the TSO.

- 77 Among the four main Russian supply routes, the Nord Stream corridor kept operating at the highest capacity. The interconnector, was operated almost in full across 2021 and Q1 2022, while in the beginning of June 2022 flows dropped to some extent following the halt in flows to Denmark, the Netherlands and some German companies. By mid-June 2022, flows further dropped in view of the technical issues previously discussed. On the other hand, the case of certification of the offshore Nord Stream 2 interconnector has been cancelled as part of the EU sanctions on Russia after Russian attack on Ukraine.
- 78 Flows across the Belarus-Polish supply corridors saw a 22% YoY decline in 2021 (41 bcm/year, a 73% utilization ratio). The drop was intensified after the termination of Gazprom’s long-term capacity contract at the Yamal-Europe pipeline in May 2021. Gazprom firstly secured new capacity at organised auctions, opting for more short-term products, but since autumn 2021, the use of the pipeline wavered. Flows first visibly dropped in Q4 2021 amid the unwillingness or stated incapacity of delivering additional gas volumes. And in May 2022 Gazprom halted flows after imposing sanctions against the company that owns the Polish segment of the pipeline.

- 79 The flows of Russian gas across the Ukrainian corridors were significantly lower YoY in 2021, primarily as a result of the new lower threshold committed in the five-year transit agreement⁵². The outcome of geopolitical tensions and the start of the war made flows across Ukrainian corridors to fall further, by 37% YoY in Q1 2022. For example, flows into Hungary and Romania were completely suspended from March and April 2022 respectively, while from May 2022 the transmission of Russian gas through the Ukrainian territories under Russian military occupation faced some discontinuity. The 38.6 bcm transited in 2021 was 13% lower than the volumes transited in 2020 and accounted for only 35% of the aggregated nominal capacity of the Ukrainian corridors. The gas volumes intended for Hungary and Romania were re-routed into the second line of Turk Stream, Balkan Stream. The latter eventually delivered 12.2 bcm/year at the Turkish-Bulgarian border⁵³. Ukrainian gas transit via Slovakia kept the highest volumes in relative terms, but has shown higher than usual variability in use. Finally, the flows of Russian gas into Finland and the Baltic States dropped by 4% YoY amid slightly higher imports of LNG to the region. From April 2022, Baltic States have halted Russian gas imports.
- 80 Germany had been acquiring a more relevant transit role for transporting Russian gas to other parts of the EU in recent years, as the Ukrainian routes gradually lost their importance. This role was expected to be strengthened by the merger of its two market zones in October 2021 and, importantly with Nord Stream 2 coming online. But the decision to cancel not only the project, but to shift away from Russian supply across the next couple of years radically changed the context. Germany heavily depends on Russian flows, and despite, has announced plans to develop four new LNG FSRUs, two coming operational by December 2022 and the others by 2023. So far, from Q1 2022 Germany has been importing more LNG via Belgium and the Netherlands as well as more pipeline gas from Norway.
- 81 TAP also played a role in import diversification. It flows gas to Greece and Bulgaria since the end of 2020, and serves Azeri gas to Italy as of January 2021. Deliveries via TAP covered for 9% of Italian demand in 2021 (7 bcm/year), and consequentially dropped gas flows intended for Italy across the Austrian and Swiss corridors (18% YoY). Moreover, NWE hub prices were generally assessed higher than the prices of the long-term contract with Socar. In fact, Italy exported gas to Northwest Europe via the Transitgas pipeline across several weeks and particularly in December 2021, when PSV traded at discount to TTF thanks to mild temperatures and relative abundance of gas supply in Italy.
- 82 The supply of Algerian gas to Spain and Portugal faced a significant restructuring from Q4 2021 onwards. The contract to transit gas via Morocco and then into the Iberian Peninsula throughout the GME interconnector expired in October 2021. Within a politically tense context between the two North-African countries, the contract was not renewed and hence flows across GME were cancelled. Sonatrach diverted a part of the flows to the Medgaz interconnector, which directly connects Spain and Algeria. The full use of Medgaz (10.5 bcm/year of nominal capacity) plus additional deliveries of LNG have preserved the export levels of Algerian gas into the Iberian Peninsula. While gas imports from France initially increased to offset the falling gas imports from Algeria, from Q1 2022 onwards the flows were predominately directed from Iberia into France to move LNG into Northern Europe.
- 83 Gas flows from the UK onto the Continent across the IUK and BBL interconnectors significantly increased from Q4 2021. After the expiration of various long-term supply contracts in the last years, both interconnectors became more price-responsive. In the past, hub spreads most often didn't cover for transportation costs, flows remained modest on average in both directions. However, since Q4 2021, and critically across Q2 2022, flows from the UK into Continental Europe have boosted. Increased LNG imports reached the large UK regasification terminals (and then Europe via BBL and IUK) to offset reduced Russian flows. To illustrate, flows from the UK into the EU from January to May 2021 had been almost negligible, as opposed to 10.2 bcm from January to May 2022. Both offshore interconnectors have been used close to maximum technical capacity in the last couple of months.

52 By the end of 2019, Ukraine and Russia signed a five-year agreement setting minimum ship-or-pay transit flows across the Ukrainian network: 65 bcm/year for 2020 and 40 bcm/year for 2021–2024.

53 Following the expiration of transit contracts with Romania, Gazprom redirected part of the previously Ukraine-Romania-Bulgaria flows into the Balkan Stream. Additionally, while the segment connecting Hungary from the Turkish-Bulgarian border was being built, Romania became a transit country to flow gas into Hungary. Since October 2021, Balkan Stream reaches Hungary via Serbia.

84 Finally, Ukrainian imports from the EU dropped by six times down to 2.6 bcm, with the Slovakian route leading, followed by Hungary and Poland. Flows from the EU were very limited during Q4 2021. The bulk (89%) of the Ukrainian imports from MSs were netted by backhaul flows, following the implementation of common interconnection agreements in recent years⁵⁴.

1.2.2 Infrastructure investment

85 Policy and market developments sent opposing signals to investors in new gas infrastructure throughout the year. On the one hand, following the EU energy transition ambition, the TEN-E Regulation⁵⁵ was revised, setting new eligibility rules for funding cross-border energy infrastructure. The EC proposal was to solely prioritise and finance low-carbon gas infrastructure as well as, principally, electrical interconnectors and the deployment of offshore renewables. As such, the new Project of Common Interest (PCI) list to be presented in autumn 2023 was proposed to exclude conventional gas projects⁵⁶.

86 However, the Russian invasion of Ukraine challenged the reliability and security of EU gas supplies and accordingly strengthened the intention of the EU to phase out the dependency on energy imports from Russia. That in turn restored the need for targeted gas infrastructure investments. Those new investments should contribute to substantially rerouting flows in the EU in line with the system's new needs. Those pieces of infrastructure, which should assist to complete the internal market, have an important aim of maximising LNG attraction as well as LNG cross-border flows into non-coastal markets⁵⁷.

87 For example, the expansion of Polish LNG import capacity and related transmission lines to ensure Ukrainian access to additional volumes is gaining priority, as it does the commissioning of LNG regasification capacities in Northern Europe (e.g. Germany, Netherlands, Baltics). The enhancement of the cross-border capacity between Spain and France (STEP project, part of the larger MidCat project) to take advantage of the ample regasification capacity of the Iberian LNG terminals is also discussed⁵⁸. The Greece-Bulgaria interconnector and pipelines connecting Italy with East Mediterranean sources have also received renewed interest. Those new cross-border projects should, according to new TEN-E, accommodate hydrogen blending or the flow of hydrogen in the mid-term.

88 Before that, and across the year, two main corridors consolidated its operation in the South-East region.

- The Southern Gas Corridor initiative increased flows from the Caspian region. Aggregated flows into Greece, Bulgaria, and Italy accounted to 8.5 bcm/year, out of which 7 bcm ended up in Italy in 2021. The TAP line has a capacity of 10 bcm/year, which could be doubled by enhancing compression station investments. While extra capacity has not been offered yet, the EC (see REPowerEU communication) as well as stakeholders from Austria and Bulgaria have expressed interest about attracting new Azeri supplies⁵⁹.
- Turk Stream's second line – Balkan Stream – reached Serbia in early 2021 and connected Hungary in October 2021 (with 6 bcm/year of nominal capacity), with the by then final aim to reach Austria in 2022. The Balkan Stream line has a capacity of 15.75 bcm/year, intended to divert exports that used to be transported via Ukraine,. The expansion of the project and its future relevance is, however, put on hold.

54 The only EU border point at which Ukraine holds firm entry capacity is Budince, on the Slovak border. This means that in the absence of gas transits from Ukraine into Hungary and Poland, Ukrainian importers (netting out volumes) face more restrictions to acquire gas. However, both in Hungary and Poland firm capacity developments are ongoing to guarantee more flows.

At the end of the year, Ukrainian grid operator GTSOU said it had been working with its Hungarian counterpart FGSZ to offer firm gas cross-border capacity from Hungary to Ukraine.

55 [Regulation EU 2022/869](#) on guidelines for trans-European energy infrastructure.

56 The proposal considers two exceptions on Malta and Cyprus to fund one gas interconnection project that will serve to end the isolation of the two islands from the rest of the EU network. Those projects converting gas infrastructure to transport or store low-carbon gases will be eligible for funding until the end of 2027. In November 2021, the commission proposed the fifth list of Projects of Common Interest (PCI), which still included 20 conventional gas projects, including the already mentioned Alexandroupolis LNG terminal and the Greece-Bulgaria interconnector among others.

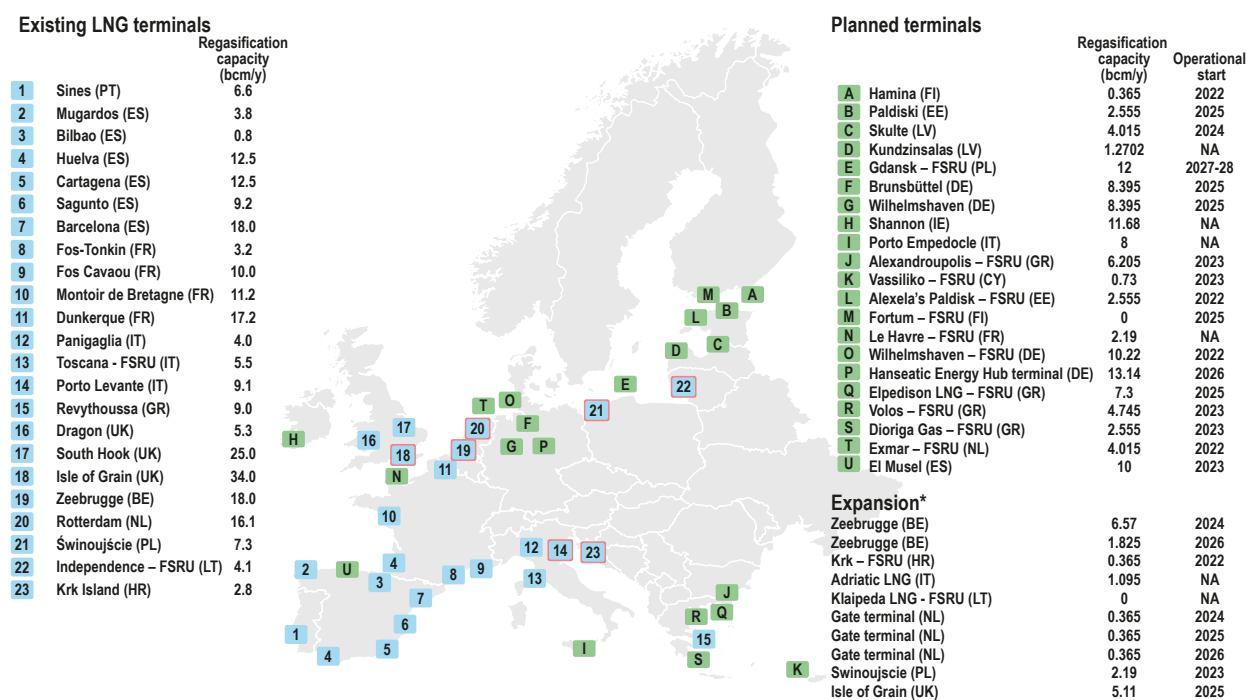
57 The REPowerEU Plan foresees new investment in new LNG infrastructure and cross-border interconnectors on the range of 10 billion of euros during the 2022-2030 period.

58 There are diverging views about the project, which might not be fully adapted to the current crisis due to its several year lead time, high costs and physical constraints to flow gas from South to North within France, and to re-export gas from France to Germany or Belgium.

59 TAP is running a market test to examine its expansion for long-term capacity, while in parallel is also offering more short-term capacities at PRISMA.

- 89 The mentioned 3 bcm/year Greece-Bulgaria Interconnector (IGB) is expected to be commissioned by mid-2022. It will enable to directly interconnect Bulgaria to the Southern Gas Corridor⁶⁰, and later on to the new Greek LNG terminal planned in Alexandroupolis (5.5. bcm by the end of 2023). Another 1.8 bcm/year pipeline between Bulgaria and Serbia is expected to be commissioned in 2023.
- 90 Furthermore, the new Baltic Pipeline, set to connect Poland to Norwegian gas fields via Denmark, aims to start its operation by October 2022, with a capacity of 10bcm/year to be reached in 2023⁶¹. The expansions of the Polish-Ukrainian route could allow Ukraine to access LNG imports via Poland, whereas the Poland–Slovakia Interconnector, expected to be commissioned by the October 2022, should contribute to further integrate the CEE region and offer access to LNG from Baltic Sea (the bidirectional pipeline has a capacity of 4.7 bcm in direction form Poland to Slovakia and 5.7 bcm from Slovakia to Poland). Moreover, the 2 bcm/year bidirectional interconnection between Poland and Lithuania, GIPL, operates since May 2022 (with dominant flows from Lithuania into Poland).
- 91 LNG and consequently LNG infrastructure, as already discussed, gained significant attention. The Croatian Krk terminal entered commercial operation in January 2021, with a nominal regasification capacity of 2.6 bcm/year. Germany has announced plans to operate two new LNG terminals by 2023 (18 bcm together) and Belgian Zeebrugge terminal will add 6 bcm/year of regasification capacity in 2024. In Spain also the El Musel terminal is expected to enter in operation in 2023. In addition, France, Italy and Poland are exploring capacity expansions at their terminals, driven by market interest and the reinforced reliance on LNG, following the plans to reduce Russian flow dependency in the future. Together, the projects in discussion could add circa 40 bcm/year of regasification capacity by 2024. Moreover, interest in floating regasification terminals increased with, among others, Estonia, the Netherlands and Germany acquiring units to enter in operation in the coming months. An overview of all existing and planned EU LNG terminals is provided in Figure 18.

Figure 18: Overview of existing and planned EU and UK LNG terminals – Q2 2022



Source: GIE and ICIS Heren

Note: Planned and announced terminal include terminals with Final Investment Decisions and the ones announced. Terminals with capacity expansions are marked with pink outlines.

60 Azeri gas currently flows into Bulgaria across the Kula-Sidirokastro IP at the Greek border, due to delays in IGB completion. Bulgaria signed a 25-year contract for 1bcm/year with SOCAR (Azerbaijan).

61 PGNiG signed a 6.4 bcm contract with the Danish Orsted from 2023 to 2028, while it plans to expand its own production in the North Sea.

1.2.3 Analysis of LNG market developments

1.2.3.1 Trends in EU and global LNG imports in 2021

Evolution of EU LNG imports

92 EU and UK LNG imports decreased by 25% in 2021 compared to 2020. The price spreads between Europe and Asian gas markets, along with the need to replace Russian flows, highly determined the volumes of LNG that shored in the EU across the different quarters.

- From Q1 2021 to Q3 2021, spot LNG cargoes drew away from Europe into higher-priced Asian-Pacific markets, amidst a rebound in global economic activity and tight global LNG supply triggered by some production outages⁶². Asian buyers acquired massive volumes of LNG to replenish their low storage stocks as well as secured deliveries for the winter season, signing new bilateral contracts for that⁶³. South American markets, such as Brazil, also increased LNG imports due to an intense drought that limited the production of its hydro-power generation. Although 25 bcm of extra LNG were produced YoY in 2021, the rise was not ample enough to meet all the additional requirements of global LNG demand, out of which only Asia accounted for 30 bcm/year.
- From October 2021, EU LNG imports began to recover as a result of the augmented global production (led by some resolved outages, but also by the record high price margins), the decreased imports from Asia⁶⁴ (milder weather, robust stocks, but also a turn to coal in China in view of high prices) and importantly, stronger EU hub prices⁶⁵. The surge was substantial from December 2021 and further strengthened in Q1 2022.
- Since the end of February 2022, European LNG imports have reached new historical highs to offset and gradually shift away from decreased Russian flows. Short-term supplies from the United States alone contributed to more than 50% of the LNG import growth in the first half of 2022. In addition, following the EC and MSs high-level political agreements with LNG producers, additional volumes have been acquired from Qatar, the US and Algeria.

93 The volatility of EU LNG imports is, amongst other factors, a result of the enhanced global competition for LNG and the rising share of destination flexible, *spot or shorter-term* LNG contracts. Both factors have increased the price sensitivity of EU LNG imports.

Defining types and specificities of LNG supply contracts

- **Spot volumes** refer to discrete cargoes offered by LNG producers or trade portfolio aggregators⁶⁶ for delivery within 3 months of the transaction date. Those cargoes tend to shore into markets according to regional price signals.
- **Short-term supplies** refer to bilateral supply contracts of a reduced duration, ranging from a few months to a few years (i.e., up to 4). These cargoes are often subject to short-term redirections and/or price arbitrages, stemming from their higher end-point flexibility along with different profit opportunities per varying shipping costs and regional hub prices.
- **Long-term contracts** refer to bilateral supply agreements signed between counterparties for larger volumes over longer periods, customarily of several years. Prices tend to be indexed to oil, hub prices, or a mix of both. The contracts may or may not include **destination clauses**, which fix the cargo's delivery location and therefore limit diversions and/or reselling. They may also include **take-or-pay clauses**, which oblige the buyer to take a minimum quantity of gas or face a penalty.

62 According to the IEA, the total LNG production capacity affected by outages in 2021 was 53 bcm, which is equivalent to nearly 9% of nameplate capacity. This represents a 44% increase compared to the 2015-2020 average.

63 The rising Asian demand was predominately weather-driven, but also assisted by low nuclear availability, some coal-to-gas shifts for power generation and milder COVID-19 impact on the economies of the region.

64 In Q1 2022, LNG imports into Asia declined by 16% from 2021 levels, dropping to near five-year lows.

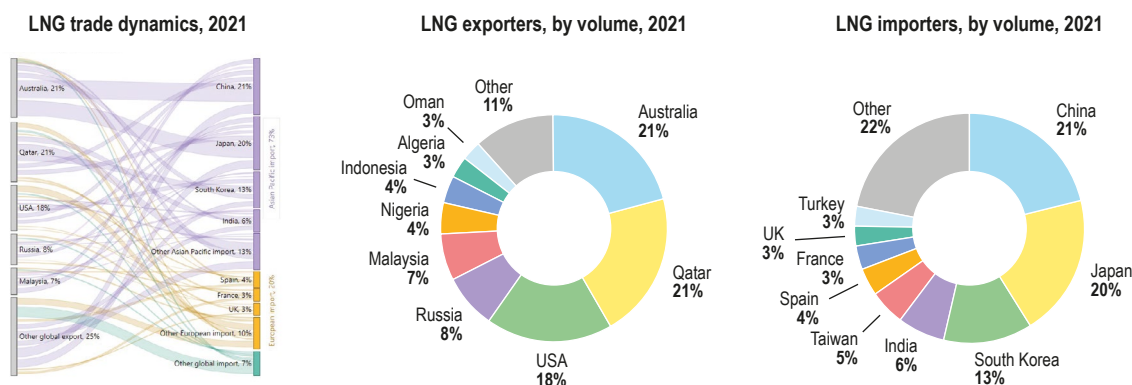
65 In an unprecedented trend, LNG spot cargoes started to reroute from Asian towards European markets once the regional price spreads inverted. Furthermore, EU buyers broadened their contracting options; as an example, Australian LNG reached EU hubs, which is quite unusual.

66 i.e., companies that may acquire LNG from different producers and that may intermediate and sell partial volumes of cargoes.

A global perspective

- 94 The level of integration between the main global gas markets has significantly increased in recent years as a result of the growth in global LNG trade. LNG has become the core vector, balancing regional demand with global supply, hence increasingly driving regional price convergence. More than 500 bcm of LNG were traded worldwide in 2021, representing 35% of global gas trade. Compared to a decade ago, this is a rise of approximately 40%.
- 95 While the main global gas markets will continue integrating towards the formation of a single one - similar to how the oil market is organised today - the global LNG market is still segmented along two main ocean basins: the Atlantic basin, with predominantly European buyers, and the Pacific basin, with mostly Asian buyers. Leading global LNG producers distribute their sales in accordance with their geographical locations, as Figure 19 shows. However, the enhanced competition for global LNG resources, coupled with the development of price-responsive short-term markets, have made cross-basin LNG deliveries increasingly interdependent. Such short-term LNG markets aren't yet transparent, liquid exchange platforms but consists of bilateral or brokered transactions between portfolio aggregators, traders and LNG producers and buyers. The reference price signals used are EU gas hubs or other price indexes.

Figure 19: Overview of global LNG imports and exports per ocean basin and country in 2021 – % by volume



Source: IEA and GIGNL.

- 96 Other than respective geographies, import dynamics at the main global gas regions are also characterised by gas supply infrastructure and demand, as well as prevalent contracting mechanisms and price signals. Of these, contracting mechanisms and price signals have drawn increasing relevance amidst the developments in 2021 and the first half of 2022.

An overview of the main contracting mechanisms across global LNG areas

The main Asian gas markets, which together account for about 70% of global LNG imports, still lack sufficiently developed cross-border pipeline and storage infrastructure. This restricts their supply diversification options and induces their dependence on LNG to meet their rising demand. As a result, LNG procurement is largely dominated by long-term contracts, which ensure a reliable security of supply⁶⁷. Asian buyers have historically been more inclined to pay higher prices to secure spot and short-term purchases, which account for 20% of total Asian LNG deliveries. When global LNG supply became tight, flexible global LNG supply tended to draw away from EU shores into the Asian region (as was the case until Q4 2021).

Destination and take-or-pay clauses remain common in Asian long-term LNG contracts, with only about 20% of contracts allowing for annual volume transfers. Oil price indexations still prevail (70 to 80% of contracts predominantly maintain oil elements in their price indices). Although the EU hubs had also been gradually gaining ground in contract indices over the last few years, the record-high hub prices of

67 For example, while China has very ambitious plans to expand its gas infrastructure, the country still receives limited pipeline cross-border flows (circa 60 bcm/year over a 350 bcm demand, domestic production accounting for circa 200 bcm) and its UGSs can meet less than 15% of winter demand in contrast to more than 25% in the EU (although there are plans to double storages' capacity across the next 5 years, including extra LNG tanks). Japan, South Korea or Taiwan are among the largest global LNG importers, but all of them lack any direct import pipeline capacity.

2021 have hindered their use. Regarding spot cargoes, the Japan Korea index (JKM) serves as the benchmark price reference. The index is derived by market intelligence companies on the basis of reported over-the-counter trades, due to the absence of organised liquid gas exchange.

The low liquidity and limited price discovery of Asian gas hubs restrict both hedging and also opportunities to divert cargoes. However, some progress is being made. In September 2021, China launched its first spot LNG price index and also overhauled its pipeline tariff structure and LNG terminal access provisions, to further promote regional market-based pricing and competition. Japan, like Europe, is also experiencing a policy shift towards hub procurement, assisted by the expiration of several long-term contracts (in fact, 20% of Asian long-term contracts are expected to expire in the next five years). Simultaneously, however, new long-term contracts are being signed in markets like China⁶⁸, India or Taiwan, where regional demand steadily grows.

European markets, together account for 20% of global LNG imports. Prevailing long-term contracts, still nominally cover for 80% of EU LNG supplies. However, parts of these long-term volumes can be diverted and resold on a short-term basis, as a result of the regulatory elimination of destination clauses. This allows for flexibility in delivery location and thus re-routing and re-exporting opportunities. Moreover, the liquid EU hubs offer a transparent price signal for global cargoes diversion. As a result, the IEA estimates that 45-50% of European LNG deliveries are actually procured via spot and short-term contracts. The Dutch TTF hub acts as the key EU price benchmark for spot LNG. (TTF is predominantly used in the long-term contract's hub-indexed price formulas.)

Although Europe only accounts for a modest share of global LNG imports, in recent years, it became the global LNG balancing market (or market of last resort). This was due to, among other factors, its larger regasification and storage capacities, its more liquid hubs (together with the ability to switch between gas and coal-fired power generation, and the flexibility clauses granted to long-term supply contract nominations). As a global balancing market it attracted larger LNG volumes when global production was ample. However, the current tight supply scenario and the recent geopolitical developments have forced the EU market to walk out of its balancing role and act as a dynamic competitor.

The USA is a leading LNG exporter, which combines long-term contracts with important short-term and spot sales (US LNG accounted for 30% of total global short-term sales in 2021). The vast majority of US LNG production is destined for export and is competitively allocated at both ocean basins, despite the fact that the cost of shipment to the EU is relatively lower. The limited exposure to external gas imports – i.e., the large US demand (870 bcm) is mostly covered by domestic production, which relies significantly on shale gas resources – results in a lower and less volatile price at its referential and highly liquid Henry Hub. Though US LNG producers also use long-term contracts to secure the financial stability for capital-intensive production projects, their offering of spot LNG sales (namely at the TTF and JKM indices, but also Henry Hub plus shipment costs) with consistently low production costs has rendered them record high earnings in the last several months. The US is set to increase its relevance as a supplier in the coming years and is expected to overcome Australia as the main global LNG producer in 2022 (113 bcm forecast).

1.2.3.2 The EU LNG contracting equilibrium also attracts renewed attention

97 The record high prices of spot and short-term LNG imports in 2021, together with the strategic aim of further diversifying EU gas supply via strengthening LNG imports, have raised questions about the favored contractual equilibrium to procure LNG in the years to come.

98 A couple of interlinked factors influence the proportion of long vs short-term LNG contracting in the EU. The primary one relates to market participants' preferences and needs, which partly shift with time. EU suppliers with a heavy reliance on LNG to meet demand had commonly subscribed long-term bilateral contracts to limit acquisition risks. Those contracts ensured a more secure return for producers' investments and arguably more stable prices to LNG buyers. A substantial number of long-term LNG contracts still prevail today in the EU, yet a large portion of those are destination-flexible.

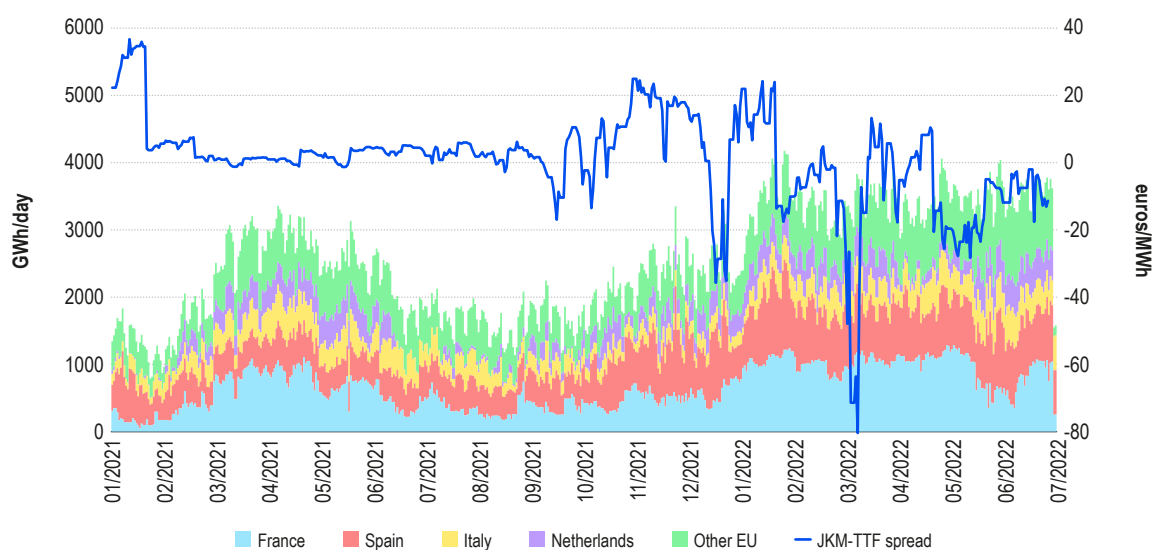
99 In parallel, the steady development of a liquid global LNG spot market (on the rise for some years, despite

68 Chinese companies have committed more than 60 bcm of new LNG term contracts since 2021.

the still relatively modest absolute volumes offered in it) together with the extended use of the services of LNG portfolio aggregators has enabled EU importers to optimize their supply portfolios on a shorter contractual basis.

- 100 However, as discussed, LNG spot and short-term volumes are price-responsive and hence more exposed to stronger global competition. That has been making EU LNG imports more irregular. For example, as Figure 20 shows, until Q3 2021, LNG imports chiefly fell in those Member States with a higher relative reliance on flexible LNG cargoes in view that Asian price signals were more attractive. On the contrary, LNG imports strongly rebounded since Q4 2021, when the high-priced EU hubs managed to attract extra spot LNG cargoes.

Figure 20: Overview EU LNG send outs in comparison to TTF vs JKM month-ahead price spreads – January 2021 – June 2022 – euros/MWh and GWh/day



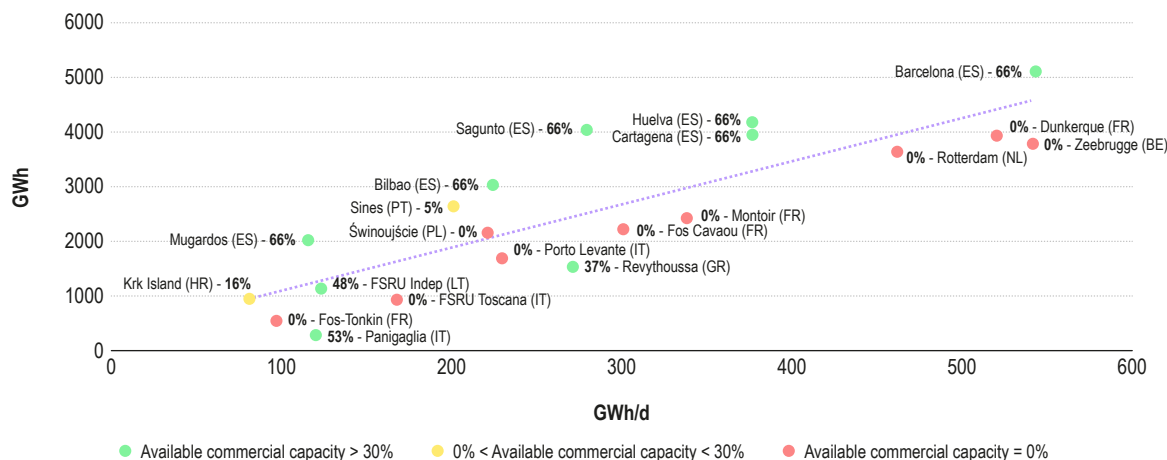
Source: ACER based on ICIS Heren and GIE.

Note: The figure analyses the total LNG send-outs. LNG imports and actual regasification values are well related, with a time-gap of a few days.

LNG capacity accessing and spot deliveries

- 101 Another factor that might affect the contractual equilibrium of LNG is the availability and nature of the capacity products that settle LNG terminals' access rights. Sound differences in capacity arrangements (as well as in capacity availability) remain across terminals, and not all of them offer the option to accommodate spot cargoes acquiring (primary) capacity at short notice.
- 102 Short-term primary capacity is generally more often available at terminals with larger storage to regasification ratios. This is because a higher buffer to store LNG tends to ease a more modular terminal operation. That tends to increase the opportunity of offering some extra downloading slots on a short-term basis, which can facilitate the accessing of spot cargoes.
- 103 Conversely, the terminals with lower storage to regasification ratios tend to download and regasify the gas in a more regular manner by design. Whilst this tends to reduce the relative storage needs (and thus the investment costs), it may also restrain the opportunities for offering extra capacity slots at short notice. Hence, larger shares of long-term contracted capacity tend to be observed at those terminals. Figure 21 offers an overview of the storage to regasification ratios at EU LNG terminals and connects their values with the available commercial short-term capacity in February and March 2022.

Figure 21: Overview of storage to regasification ratios for selected EU terminals in 2021 vs short-term capacity availability in February and March 2022 – GWh and % of total capacity commercially available



Source: ACER based on Gas Infrastructure Europe.

Note: Storage and regasification commercial capacities at Spanish regasification plants are managed together, in view of the recently implemented virtual access regime. See case box in page 43.

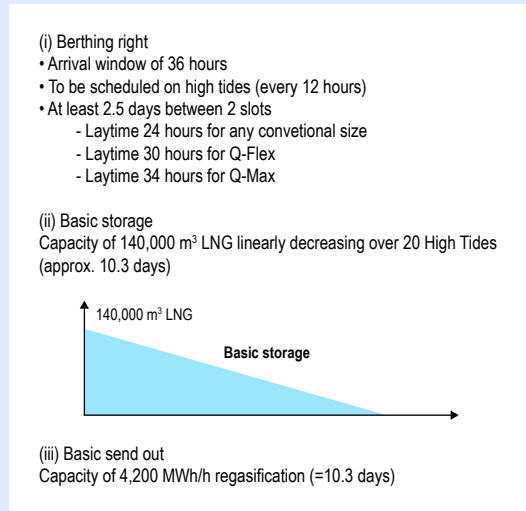
104 The design of the LNG terminals is influenced by a number of technical aspects, by the services they offer and the overall market needs of the systems they operate in. Among the technical aspects stand out the tools available at the related systems to modulate gas supply (to which LNG terminals contribute). For example, some systems take advantage of higher network line-packs, some others benefit from larger and flexible UGS sites and others still may meet their supply flexibility needs via more elastic import contracts. The different markets may also have dissimilar downstream flexibility needs.

105 While higher availability of short-term capacity might facilitate the attraction of spot LNG cargoes, there is no univocal rule. Similarly, the lack of available primary capacity, as a result of its long-term full subscription, does not preclude spot or short-term LNG deliveries to the terminals. LNG buyers aim at maximizing their trading opportunities in view of their contractual and capacity portfolios. For example, an incumbent company can make use of its primarily secured long-term capacity to back up spot trading opportunities (it may divert long-term committed supply to higher-priced areas as well⁶⁹). On the other hand, the unused primary capacity can be acquired by alternative suppliers to bring spot cargoes in by means of secondary capacity acquisition and/or when the primary capacity is released via congestion management procedures. In Q2 2022, downloading slots auctioned or contracted in the secondary market have become significantly more expensive in certain jurisdictions in view of the high profitability of LNG sellers due to the record high prices at continental hubs. In that respect, the recent Hydrogen and Decarbonised Gas Market Package requests implementing more transparent and non-discriminatory booking platforms to resell unused contracted capacity on the secondary market.

69 For example, across the first half of 2022, and in view of the EU rising LNG import needs, companies with secured long-term capacity rights have acquired sizeable volumes of spot LNG to LNG portfolio aggregators. When the latter lacked sufficient regasification capacity the transactions resulted in more favourable prices.

Zeebrugge LNG terminal case study

How the lack of available primary capacity, as a result of its long-term full subscription, does not preclude substantial spot or short-term LNG deliveries



The Belgian Zeebrugge LNG terminal has a throughput capacity of 9 bcm/year. Following an open season conducted in 2003 (and a subscription window introduced in 2019) its entire primary capacity has been allocated on a long-term ship-or-pay basis. The terminal capacity is commercialized by means of slots, which enable terminal users to (see figure i):

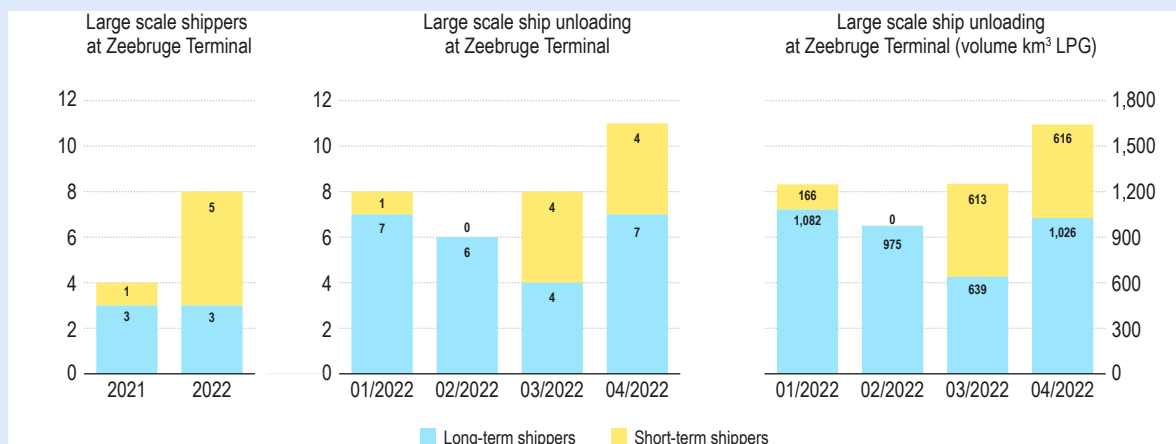
- arrive and berth their LNG vessel within a defined window of 2.5 days (equivalent to 10 tides),
- use a basic storage capacity of 140,000 m³ LNG, which linearly decreases over 10 days,
- use a basic send-out capacity of 4,200 MWh/h during the abovementioned 10 days.

This operational model allows the terminal to receive LNG cargos every 2.5 days. Although the terminal capacity is fully booked, it is still possible to find stretches of 2.5 consecutive days where no ship arrival is scheduled. Fluxys LNG, the terminal LSO, recurrently identifies those days (the identification is done on the basis of a rolling berthing schedule built with data provided by LNG users) and offers the available slots as additional primary capacity, via an auction or on a FCFS basis⁷⁰.

Secondary capacity acquisition and/or congestion management procedures

Belgian regulation requires LNG terminal users to offer unused capacity on the secondary market, either over the counter or via Fluxys dedicated website. If a terminal user informs Fluxys LNG that it has slots it does not intend to use, the capacity is also made available on the site⁷¹.

This combined approach has allowed the terminal of Zeebrugge to receive 9 ships from 5 short-term shippers between January and April 2022. They represent an additional 1.4 bcms of LNG as the second figure shows.



Source: Fluxys LNG

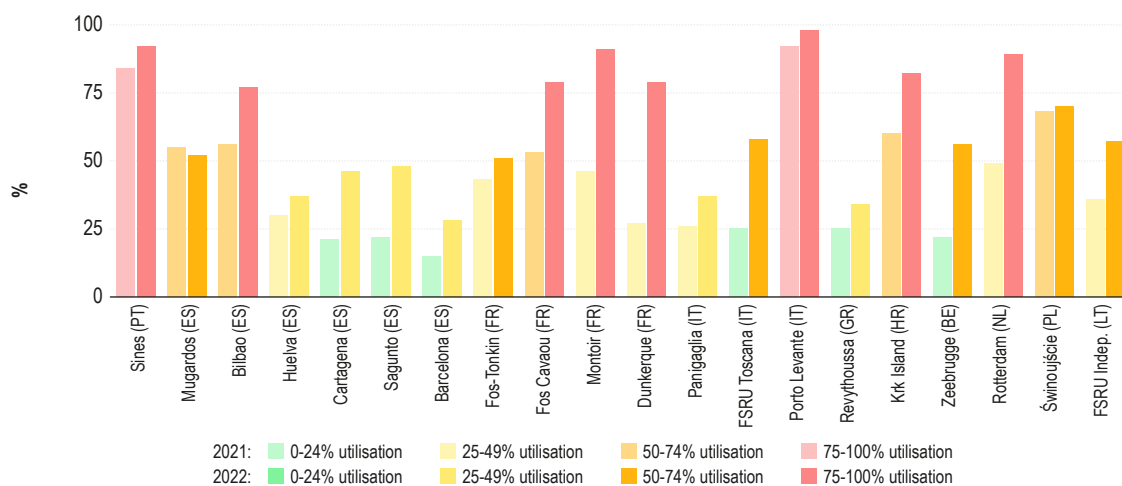
70 Moreover, Fluxys LNG, in coordination with its long-term shippers, is consulting on the possibility to optimise the annual plan schedule during the year to create additional opportunities to offer primary spot slots.

71 In line with the provisions of the Hydrogen and Gas Decarbonisation Package, Fluxys LNG is consulting on the possibility to publish on the secondary market any slot for which a terminal user has not confirmed its use 21 days before the start of the slot. Moreover, Fluxys LNG, is considering the development of a common secondary market platform together with the other members of GLE (Gas LNG Europe).

1.2.3.3 EU LNG terminals utilisation overview and drivers

106 Figure 22 offers an overview of the average annual utilization of EU LNG terminals in 2021 and the first half of 2022. In 2021, the EU average accounted to 38%, which is 3 percentage points less than in 2020, as a result of the discussed substantial drop in LNG imports for most of the year. However, from January to June 2022, the average use rate has risen above 60%, which adds perspective to the EU's increasing reliance on LNG imports.

Figure 22: Overview of EU LNG terminals' utilisation ratios – 2021 (left) and first half of 2022 (right) – % of nominal capacity used



Source: ACER calculation based on GIE.

107 There are ample differences in use among MSs and plants. The largest relative utilisation was observed in 2021 at the Portuguese, Polish and selected Italian and French terminals. At those terminals, long-term capacity contracts tend to prevail. However, the number (and as discussed, the type) of cargoes that head towards each plant is shaped by a combination of additional factors. They include the type of supply contracts, the LNG prices relative to other gas sourcing options, global competition for spot cargoes, terminal services and tariffs and the trading opportunities at their linked hubs.

108 Neither the products underlying the accessing rights, nor the type of (spot or long-term) cargoes that shore into the different terminals can be always categorised. Long-term contractual capacity positions are, however, deemed to persist in a majority of plants. For example, in Poland, Belgium or some UK terminals, all the primary capacity is fully acquired under long-term term contracts by unique incumbents. In general, longer-term bookings tend to prevail at the newest but also at exempted terminals, to back their business cases. Long-term bookings increasingly include the partaking of global LNG producers, such as Qatar Petroleum in Belgian Zeebrugge or at the British South Hook.

109 Finally, the terminals' tariffs are also an additional relevant factor that influences their utilisation. Not only the absolute tariff levels – which are benchmarked in Figure iii in Annex 1 – but also the split between fixed and variable charges can affect the plant's booking profiles. Lower fixed costs tend to be associated with higher long-term bookings. For example the German NRA BnetzA is considering granting a 40% discount in the LNG send-out tariff into the country's network from 2023 (for annual and quarterly products), to foster LNG contracting. Similar LNG tariff discounts are widespread in many jurisdictions.

110 The case study below offers an overview of the access regime and the prevailing capacity products at the Spanish terminals. The case underlines that the recently implemented virtual access regime has favored the LNG trading activity in the country, backed in part by a higher availability of short-term capacity.

Spanish LNG terminal case study

High degree of access flexibility, a long range of capacity products and flexible use conditions and services back LNG trading opportunities.

LNG plays a key role in the Spanish natural gas market. The joint capacity of the six Spanish LNG terminals amounts to 59 bcm/year. This is more than enough to satisfy the Spanish domestic gas demand, which amounted 32 bcm in 2021 (54% met with LNG) and export gas abroad.

The Spanish LNG access model allows users to contract a set of services that better fit their needs. Terminals' users can book capacity on a short or long-term basis, either in the primary or in the secondary market⁷², while they can unload, store, trade and/or regasify (but also liquefy and/or reload again) LNG, depending on their strategic considerations. There are no minimum regasification volume or speed obligations and users can surrender or resell the booked capacity in the secondary market.

One of the main advantages of this model – built on the Virtual Storage Tank (TVB) implemented in 2020 – is that any quantity of LNG unloaded at any of the six LNG terminals along the Spanish coast is instantaneously located at the virtual LNG hub⁷³. The Virtual hub has a total storage capacity of 23 TWh (around 23 standard LNG cargoes) and regasification rate of 1.9 TWh/day (i.e. 2 LNG cargos per day). These features have not only increased liquidity and trade opportunities in the Spanish market in recent years, but also simplified the booking, nomination and balancing processes.

Concerning allocation, capacity is assigned through auctions for unloading (or loading) slots, with multiple products: yearly, quarterly, monthly, daily and intraday, in a very similar way as done at EU interconnection points. The auctions are held on a monthly basis. If there is free capacity in a given month, further auctions would be conducted, or allocated by First Come First Serve procedures at the end. A single access agreement allows users to contract any kind of capacity and operate in a standard way throughout the whole Spanish gas system.

While it is possible to book capacity for a fifteen years' timeframe, a part of the capacity is reserved to be offered in the short term⁷⁴. Longer-dated capacity enables to plan operations well in advance, while short-term capacity helps to accommodate changes in demand and/or to capture market opportunities and attract spot LNG cargoes. Moreover, unloading and loading slots offer certain flexibilities; users can modify the location, the date (1 month in advance), the size of the vessel and the amount of LNG, with the viability of the Technical Manager of the System.

Therefore, there is a very high degree of dynamism associated with the slots booking in the Spanish LNG terminals. Table i summarizes the terminals' activity during March 2022, used here as a comparable benchmark similar to other months:

Physical activity: loads and unloads during the month	
Nr. of unloads during March 2022	26
Nr. of loads during March 2022	4
Contracting activity - Nr. of slots allocated	
Intra-monthly slots (for March 2022)	7
For M+1 and M+2 (April–May 2022)	7
For M+3 until M+12 (June 2022–March 2023)	13

72 The secondary capacity price must be equal or lower than the primary capacity price.

73 In fact, an LNG cargo could be unloaded at a Northern terminal and be reloaded at a Southern one.

74 In the case of unloading/loading 10% of the capacity is reserved for Month+2. For other services 15% is reserved for short-term products, distributed differently (1st quarter, 1st month and 1st daily), depending on the service. Only 50% of the capacity is offered between years second and fifteenth year (for all the services).

Flexibility activity: changes of contracted slots

Unloading slots delayed from previous month	12
Unloading slots advanced to next month	14
Surrendered slots	3
Cancelled slots	1

Source: CNMC based on LSO data

All these features have significantly facilitated access to the Spanish LNG terminals, making them more attractive for new players and hence increasing competition. Natural gas trading, both bilaterally and at the Spanish exchange (which offers a dedicated venue for LNG-traded products), has significantly increased since the new LNG model has been established in April 2020, while the number of active users of Spanish LNG terminals during 2021 has increased to 83.

1.2.3.4 Mid-term prospects of EU LNG

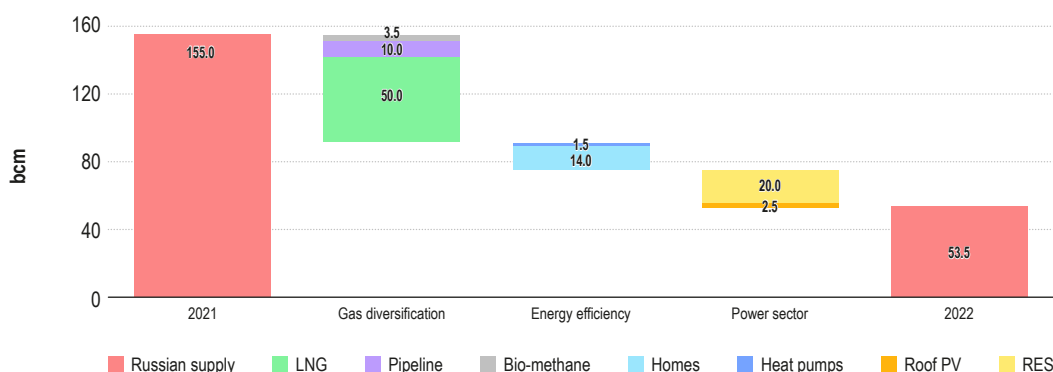
111 While LNG was hitherto aimed at increasing its share in the EU gas mix, as a means to diversify supply and promote price competition, the Russian invasion of Ukraine in late February 2022 will accelerate those efforts.

112 As discussed in the Executive Summary, the Russian attack constitutes a turning point for EU gas markets and its approach to supply security. Subsequent sanctions and political positions of the EC and Member States have manifested a clear aim to further diversify supply and minimise the dependence on Russia as fast as possible. Increased LNG imports will play the key role in those efforts, together with additional non-Russian pipeline supply and the build-up of domestic renewable gases. The strategy also entails a sizeable reduction in the final EU gas demand.

The REPowerEU plan and the options for maximising EU LNG imports

113 Recent EC REPowerEU Communication targets to replace up to 50 bcm of Russian gas per year via extended procurement of LNG. This is more than 10% of EU demand in 2021 and circa 10% of total global LNG trade in 2021. The amount has been assessed theoretically on the basis of the nominal unused re-gasification capacity and cross-border capacities in 2021.

Figure 23: Summary of REPowerEU gas supply diversification and Russian supply reduction efforts in 2022 – bcm/year



Source: ACER based on European Commission

Note: Additional measures like enhancing domestic production, fuel-substitution or freeing strategic gas reserves would also contribute to offset the dependence on Russian gas. By the end of May 2022, Europe has imported circa 40 bcm of Russian gas, which makes the 2/3 supply reduction target challenging.

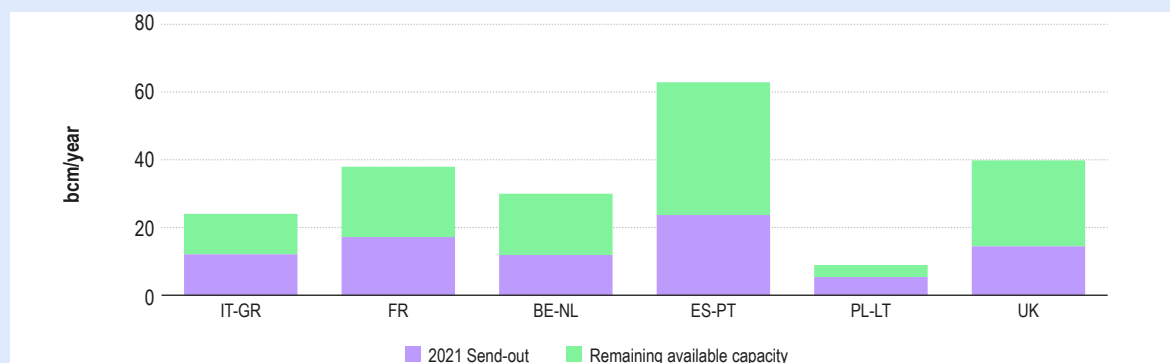
- 114 The extent to which these LNG procurement projections materialise will depend on the availability of additional global LNG. The global dimension is critical. World gas markets increasingly compete for LNG resources, at the same time as global LNG supply is expected to remain tight still for some years in view of the rising gas demand in developing economies across the world and, importantly, their use of gas to decarbonise their energy sectors (the boosted EU imports further contributing to the tightness). Moreover, some of the additional supply sources are unlikely to match Russian former pipeline supply prices and might place some higher floor on final EU prices.
- 115 High-level negotiations with global LNG producers should be instrumental to securing extra LNG supply. Those discussions should enhance mid-term stability of supply and prices by providing mutual support, including more financial stability to production and liquefaction plants' developers by means of signing new long-term contracts⁷⁵. For example, following a high-level agreement signed in March 2022, the United States (government) strives to (encourage US companies to) supply at least 15 bcm of additional LNG into the EU in 2022, with expected increases going forward (EU and UK LNG imports from US have risen by more than 15 bcms in the first half of 2022 compared to the first half of 2021, rising by a factor of 2.6). A new EU Energy purchase platform is also planned to pool EU demand for additional LNG volumes by October 2022 at the latest⁷⁶. Moreover, an ongoing dialogue with major global gas LNG buyers will hopefully detect, and possibly limit conflictual market practices that may increase global prices for all (e.g., Japan, South Korea, China, India).

Feasibility and options for maximising EU LNG imports in the short- to mid-term

The EU aims to diversify gas supply away from Russia by 2027 at the latest (with some MSs aiming for earlier deadlines as discussed). The key mechanism pondered to accelerate this target is to bolster LNG imports. The EC theoretically assessed in its REPowerEU March 2022 communication that extra 50 bcm of LNG could be attracted into EU shores by 2030 and (cautiously) already in 2022 (see Figure 23). The volume was assessed on the basis of unused regasification terminals' and cross-border pipeline capacities in 2021. Other recent assessments from the IEA and OIES offer related estimates, indicating respectively that at least 20 bcm and up to 30 bcm are likely achievable.

The extent to which these projections materialise will depend on global demand and supply developments and on the interplay of regional price signals, as world gas markets increasingly compete for global LNG resources. Moreover, the infrastructure aspects are on the stake. Figure 24 estimates the unused LNG regasification capacity at European terminals in 2021. It accounted for more than 50 bcm. The figure shows that Iberia, the UK and France had larger remaining capacity. Moreover, as discussed in Section 1.2.2, various LNG terminal expansions have been announced, with Germany expressing ambitions to develop 18 bcm worth of new capacities in 2023, while making use of floating LNG import facilities in other parts of the EU is also discussed.

Figure 24: Remaining LNG available capacity in Europe in 2021 – bcm/year



Source: ACER based on GIE. An 80% load factor is considered.

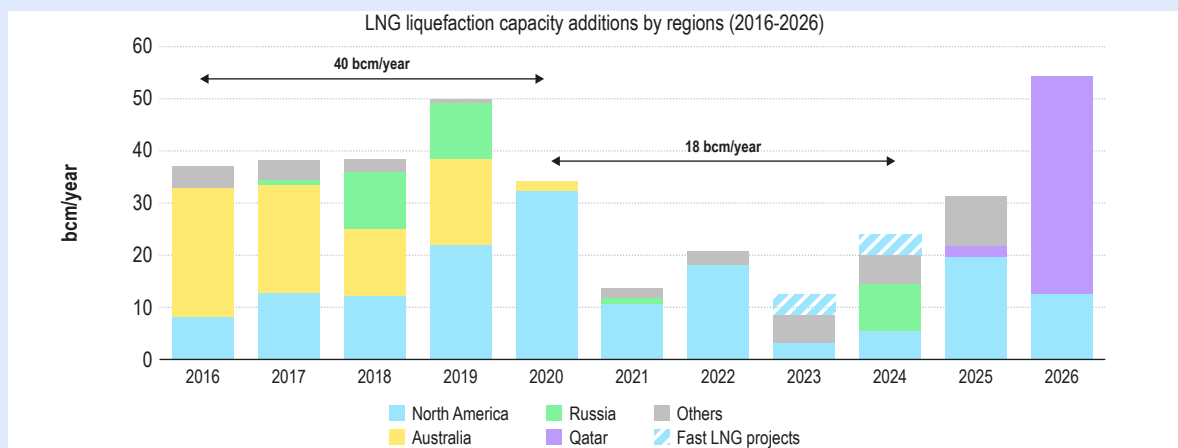
- 75 This is, among others, because LNG project developers are facing rising costs due to inflation and capital costs, which they will need to pass on to get financing and reach final investment decisions (FID).
- 76 Bruegel published a [Policy Contribution](#) in June 2022 offering suggestions to make the EU Energy Purchase Platform an effective emergency tool.

The feasibility of achieving extra LNG imports is not only subject to global LNG availability, but also to network constraints or the optimal location of additional floating units. Gas flows will need to substantially reroute if the EU system becomes increasingly independent from Russian supply via enhanced LNG deliveries. That will require a reassessment of system operation and targeted infrastructure investments.

For example, the capacity of the Iberian-French interconnector is 7.5 bcm per year. The EC has listed the expansion of this pipeline as a potential way of bolstering LNG supply significance although there are divergent views about if it might be more complex and costly than creating regasification capacity in the North of the continent. The use of UK LNG terminals to import gas to the Continent across the larger offshore interconnectors (30 bcm in total) is also an option that has been gaining traction in 2022 as argued in [Section 1.2.1](#).

With regard to global LNG availability, both supply and demand factors are of relevance. As discussed, global LNG production was subdued in 2021, affected by delayed maintenance and production outages. However, the expectation is that those problems will be gradually resolved across 2022, at the same time as total production will be augmented in view of record-high price margins. Indeed, the expanding worldwide LNG export capacity will be key for smoothing the LNG supply tightness in the years to come. The bulk of new LNG production volumes are expected from 2025 onwards as Figure 25 shows (extra 120 bcm/year estimated by the IEA), with Qatar and the US in the lead⁷⁷.

Figure 25: Start-up year of forthcoming global LNG capacity: 2016 – 2026 – bcm/year



Source: IEA

It remains to be seen how much of that production increase will be counterbalanced by the global mid-term demand surge, which will chiefly come from the Asia-Pacific region. Average estimates consider that LNG global demand could rise by at least 30-40% from 2020 until 2026, which means at least 150 bcm of additional demand. Larger demand increases outside Europe will make the competition for LNG stronger, and imply sustained high EU prices to attract more cargoes.

With a focus on 2022, the OIES estimates that global LNG production will increase by 43 bcm (30 bcm worth of brand new liquefaction terminals) while global net demand (excluding the EU) could be approximately extra 12 to 15 bcm. Only China could import circa 10 bcm more, up to 130 bcm/year. (Yet, this is a slower rate of growth than in previous years, an outcome of increasing pipeline deliveries from Russia, the economic slowdown, COVID-19-related lockdowns and the high prices, reducing China's gas demand for power generation and industrial use.) Other countries like Japan and South Korea or Taiwan are assessed to see a drop in import, likely making available those extra 30 bcm to the EU buyers.

77 The relatively modest additions in the short-term is an outcome of the structural decline in investments in upstream gas over the last few years, which focused on shifting away from fossil fuels.

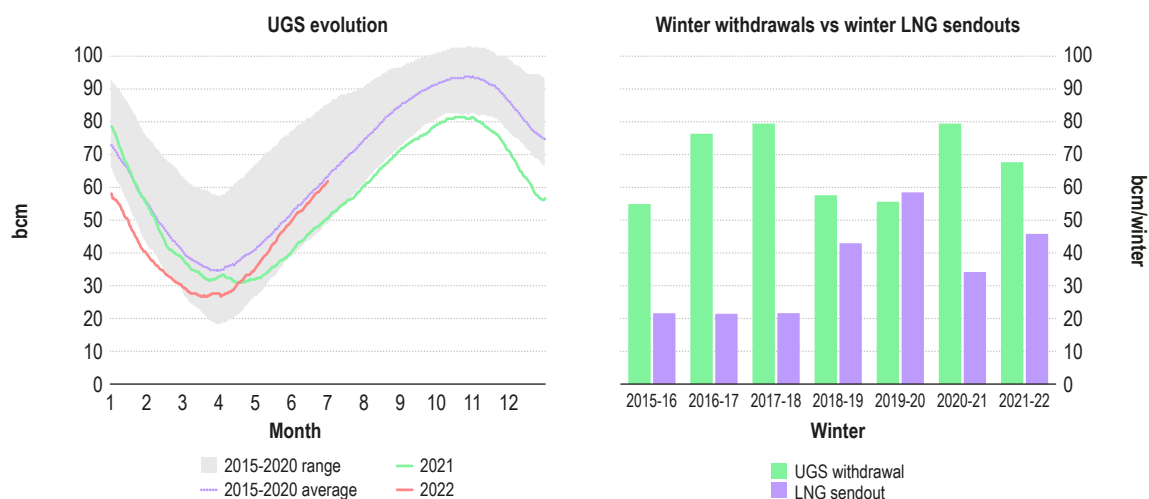
1.2.4 Analysis of underground storage market developments

1.2.4.1 Evolution of EU storages utilisation in 2021 and the first half of 2022

116 Storage levels reached record lows across the second half of 2021 as a result of a sequence of events. The low stock levels together with the reduced Russian flows put additional pressure on gas hub prices in winter 2021/2022.

117 The left part of Figure 26 underlines the drop of EU gas storage stocks across 2021, by comparing the evolution of storage levels in the last 7 years. On the other hand, the right part of the figure compares the gas withdrawals from EU storages during winter months side-by-side with the send-outs from EU LNG terminals. This part of the figure underlines that the changes in total LNG deliveries increasingly determine storage withdrawal needs and thus how the storage and LNG infrastructure complement each other during the cold season.

Figure 26: Evolution of EU storage site levels – 2015 to June 2022 – stocked bcms and LNG send-outs in comparison to storage gas withdrawals – bcms in the winter season



Source: ACER calculation based on GIE data (excluding Ukrainian and Serbian sites).

118 The evolution of storage utilisation in 2021 and the first half of 2022 is split up into four phases, each of them having specific attributes⁷⁸:

- Winter 2020/2021 was prolonged and colder than average. That, together with the fading LNG arrivals, compelled larger UGS withdrawals than in the previous years. By April 2021, storage sites were depleted by about thirty percentage points more compared to April 2020. Gas producers used the stocked gas to meet the nominations for long-term supply contract deliveries, which also contributed to the depletion of EU storage facilities.
- During the spring and summer months of 2021 injections were rather limited: 50 bcm were injected in Q2 and Q3 2021 in contrast to 80 bcm in the same period in 2020. The lower injections were a result of reduced LNG imports, the modest pipeline flows and the unattractive hub price signals⁷⁹. In addition, Gazprom notoriously did not fill up its storage sites at the levels observed in previous years, as discussed in the case box below.

78 Generally, storage levels are driven by a combination of factors that include the use of gas stocks in preceding sessions along the availability of gas on the market, the storage security of supply obligations prompted by regulations, the hubs' price signals, site access conditions and the prevailing contracts. In 2021, additional specific factors were determinant for the extraordinary outcome.

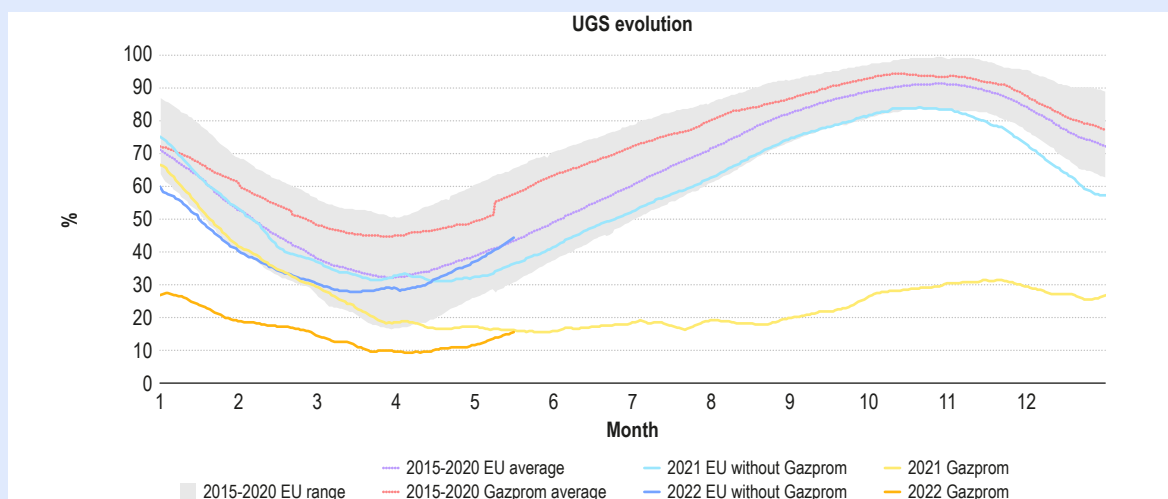
79 The rapid escalation of hub prompt prices across summer 2021 made winter-summer spreads narrow (the seasonal spreads even became negative in some instances), reducing the attractiveness of injecting gas into the storages.

Gazprom underground storages' filling levels

The low stock levels of the EU UGS facilities under the ownership or contractual control of Gazprom – 13.9 bcm, which is more than 10% of the EU's total storage capacity – were the key driver behind the lower than usual storage stocks in markets such as Germany, Austria and the Netherlands. Those MSs have negotiated access regimes and hence there are no storage obligations in force.

At the end of October 2021, Gazprom storage stocks were at an unprecedented low level of 25%, which was three times lower than the average of the rest of the EU facilities (see Figure 27). Gazprom shifted its strategy during summer 2021: it largely used its EU storage stocks to back supplies for bilateral contracts, whereas it significantly limited new injections into the storage. In parallel, the company stated that storage refilling would begin in November, once Gazprom had replenished the heavily depleted Russian sites. However, this declaration never materialised; although some modest injections were observed in the fall, they soon turned into net withdrawals. Moreover, the reluctance to acquire transportation capacity across the Yamal corridor at the short-term auctions of November and December 2021 in particular put extra tension on German storage stocks, reinforcing the high price level sentiment at EU gas hubs in the winter 2021/2022.

Figure 27: Overview of Gazprom's own or controlled storages vs EU average – 2015 – mid May 2022



Source: ACER calculation based on GIE ALSI.

Gazprom's behaviour since Q1 2022 has triggered various regulatory proposals to avoid capacity hoarding in EU storages by third-country entities.

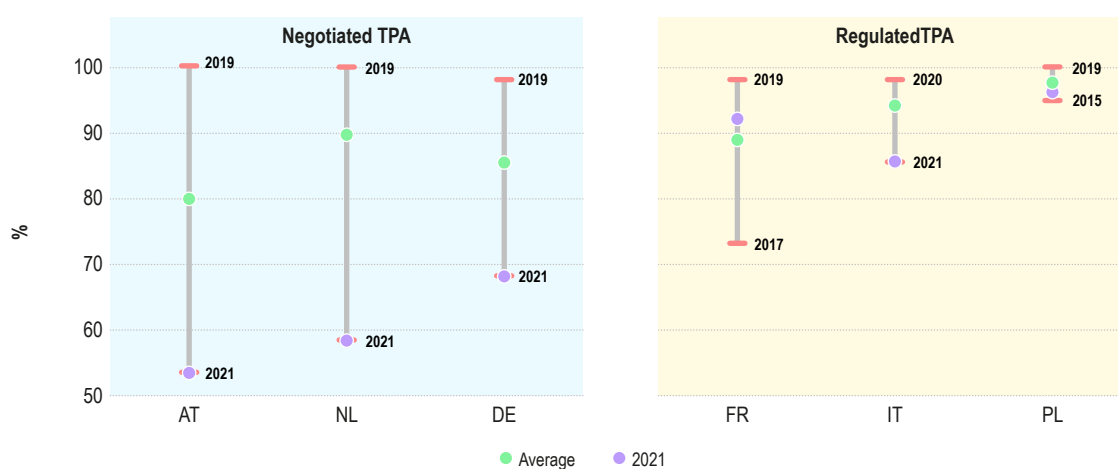
- Storage stocks reached one of the lowest levels in recent years (77% for the EU average) at the end of October 2021, with 20 bcm less gas than in 2020 available to meet winter demand. More than half of the gap was due to Gazprom's low stocks, as argued in the case box above. While MSs sent calls to shippers and operators to maintain stocks as high as possible until the end of winter 2021/2022⁸⁰, the limited Russian pipeline imports coupled with below-average temperatures and low renewable power generation prompted higher than average withdrawals in November and December 2021.

⁸⁰ This was also in order to upgrade withdrawal capacity; storage withdrawal capacities are partly reduced as stocks are diminished. See expanded considerations in the [ENTSOG Winter 2021-2022 Supply Outlook](#).

- However, withdrawals from storages eased in Q1 2022 due to mild weather and boosted LNG imports. Even if by April 2022, storages had been depleted to 26% of their nominal capacity, below five-year average, the levels were above the ones in 2021 (see Figure 26)⁸¹. Moreover, storage injections in Q2 2022 reached record highs, backed by large EU LNG imports. That led to EU storages surpassing by 9 bcm the levels stocked in June 2021, well on track to meet the 80% target by November 2022. However, again in mid-June the near-term supply outlook tightened after Russian flows across Nord Stream 1 and to various MSs halted. A sustained loss of Russian pipeline flows may create problems to reach the established storage filling thresholds, with Eastern MSs likely to be more affected.

119 Interestingly, the differences in the stock levels among MSs were higher than in the past five years as shown in Figure 28. Those differences resulted from the technicalities of the sites and more importantly, from the regulatory regimes applied. ACER has recently published a comprehensive overview of storage access regimes and indicators covering 2021⁸². The following section elaborates on these aspects.

Figure 28: Evolution of EU storage site levels for a sample of MSs – 2015 – 2021 – % of technical capacity



Source: ACER based on GIE. The red marks indicate the years when storage stocks reached max and minimum levels.

1.2.4.2 Overview of storage access regimes and storage significance per Member State.

120 EU law requires third-party access to storage, whilst MSs can choose between two different storage access regimes. On the one hand, the two main regimes affect how storage tariffs will be determined. In a negotiated tariff regime, tariffs are set without administrative intervention and storage operators charge fees on the basis of market signals, commonly taking as price reference the summer-winter hub spreads. In a regulated access regime tariffs are set or scrutinised by regulatory bodies. Regulated tariff regimes might be combined with auctions. The auctions would allocate capacity using the summer-winter price spreads as referential prices, although the final charges received by storage operators may be subject to revenue reconciliation.

121 On the other hand, storage access regimes influence the capacity allocation mechanisms used by the facilities. Under regulated regimes, auctions are a widespread procedure. Under negotiated access, auctions or open season procedures are, as is customary, complemented with direct negotiations with SSOs. Storage access rules, regardless of the choice, should allow for an efficient allocation of storage capacity and prevent capacity hoarding. As part of the allocation regime, storage operators offer products (e.g., bundled or unbundled) adjusted to the needs of the markets and also in view of the site and system technicalities.

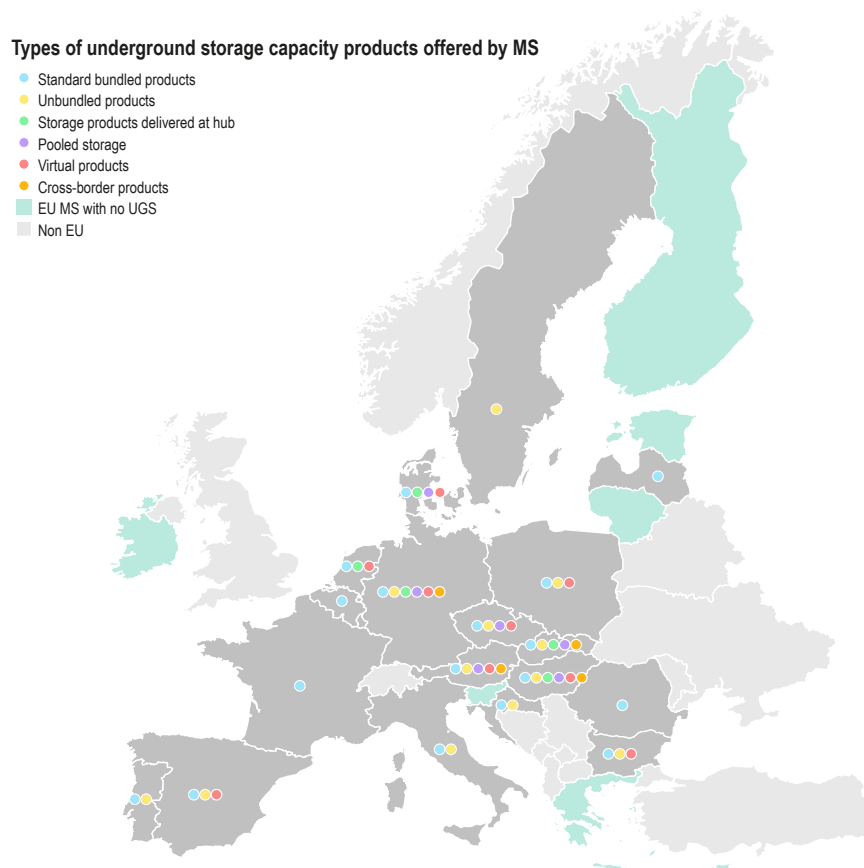
122 Finally, the chosen access regulation may impose other types of storage obligations and/or utilisation patterns. The latter can take the form of enforcing a minimum level of stock at a certain moment in time or setting limits to inject and/or withdraw gas volumes across defined periods. In some systems, strategic storage reserves are to be kept for emergency.

81 Q4 2021 plus Q1 2022 withdrawals totalled 67 bcm, -15% lower than one year before.

82 See ACER Report on Gas storage Regulation and Indicators.

123 Figure 29 offers a succinct overview of the access regimes per MS and also presents locations where storage obligations or strategic storages are available. More details about the national markets are provided in the ACER report mentioned above.

Figure 29: Comparison of underground storage tariffs and access regimes in EU MSs

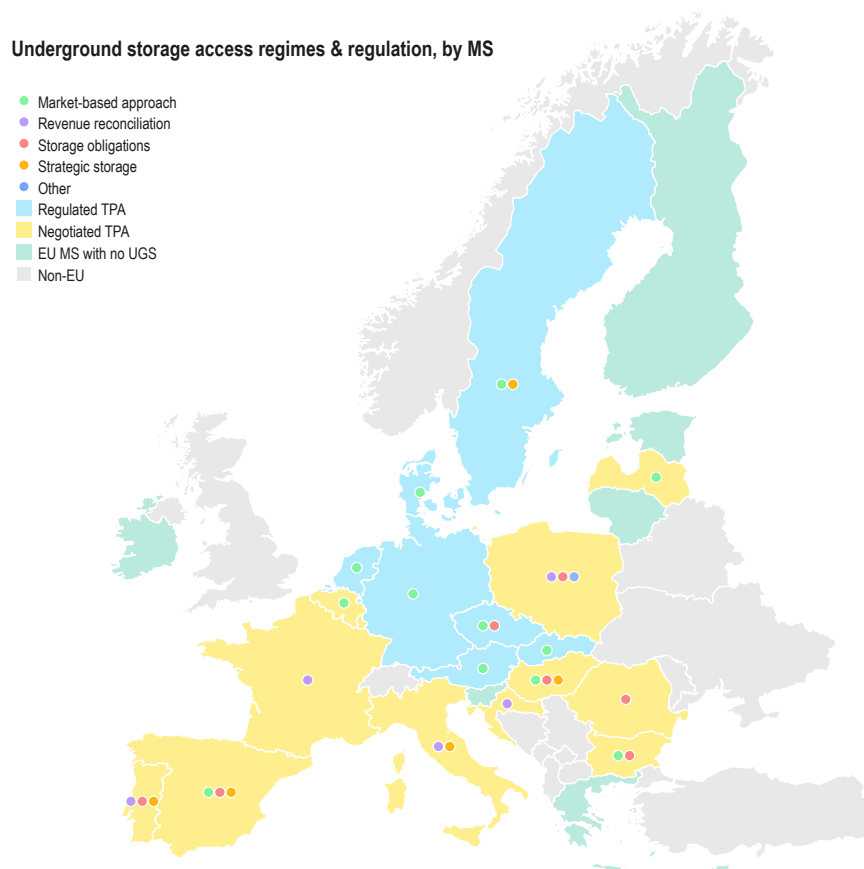


Source: ACER based on NRA data.

Notes: See expanded definitions and detailed considerations per MS in the ACER storage regulation report.

124 Figure 30, in turn, summarizes the type of capacity products that are offered in each MS (the analysis includes various sites within a given MS). Bundled products enable the injection, storing and withdrawing of gas and offer access into the network. Bundled products are standard products that all facilities must offer. However, an increasing number of operators offer unbundled products and/or flexible products, such as virtual storage or storage products delivered at the hub (which might not involve the use of physical storage assets). Again, this flexibility relates to the storage facility type and the features of the system.

Figure 30: Comparison of underground storage and capacity products offered across MSs – 2021



Source: ACER based on NRA data.

Note. See expanded definitions and detailed considerations per MS in the ACER storage regulation report.

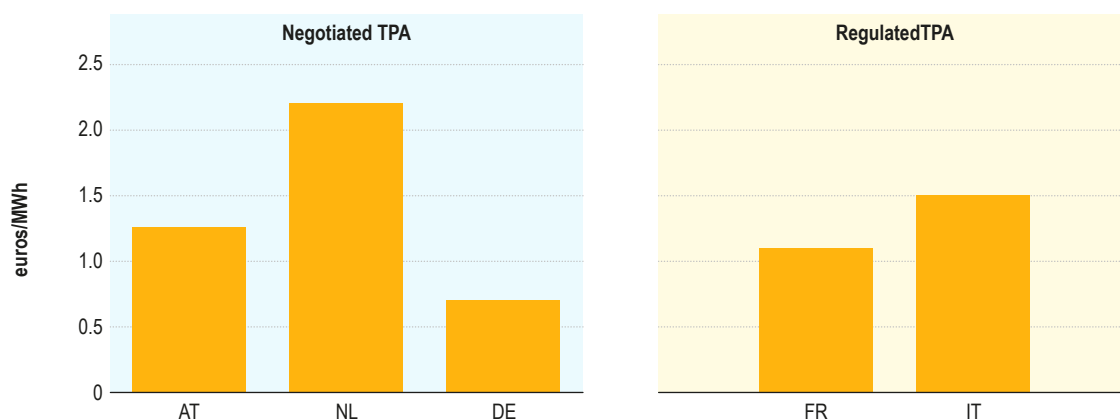
Overview of storage tariffs

- 125 Storage tariffs and costs are not straightforward to benchmark. The payments that SSOs receive may derive from individual negotiations (frequently linking storage costs to summer-winter spreads) or from an auction process (where the auction fee might be augmented by means of revenue reconciliation). Besides, in many systems, storage tariffs are reduced via cross-subsidies with the transmission network to promote the value they add to the system by securing supply.
- 126 This financial support has received renewed attention in Q1 2022. The proposal on the EU gas storage regulation⁸³ of March 2022 calls to provide financial incentives to strengthen storage injections this summer. This is to guarantee the minimum filling target set to 80% of the storage capacity by 1 November 2022 ahead of the next winter to address significant risks for security of supply due to the dramatically changed geopolitical situation. The EC proposal contains a filling trajectory and measures to achieve it. Financial assistance is of particular relevance in view of the narrow summer-winter price spreads (even negative, see [Figure 33](#)), reducing the economic incentive for filling these sites in early Q2 2022.

83 Amendment to Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply and to Regulation (EC) n°715/2009 on conditions for access to natural gas transmission networks, so called [EC proposal on gas storage](#).

127 Figure 31 offers a comparison of the average access and utilisation costs at a selection of storage sites in a selected MS. The assessment considers the bundled standard capacity products.

Figure 31: Comparison of underground storage costs across select MS sites – 2022 – euros/MWh



Source: ACER calculation based on GIE transparency platform and SSOs.

Note: The assessment is based on the seasonal bundled products tariff of the largest or representative site at each MS (RAG Storage pool in Austria, Bergemeer in the Netherlands, RWE Gas Storages in Germany, Storengy storages in France and Stogit sites in Italy). Tariffs in Q1 2022 were used as general reference. Either regulated or negotiated tariffs (if published) are considered (in some cases estimated, e.g., by using the summer/winter price spreads). In France, the assessment solely refers to the average clearing price of storage auctions organised across Q1 2021. The comparison is subject to various caveats and complexities, such as the non-unified offered period (i.e., the duration of standard products tend to be annual but can be shorter) the dissimilar capacities offered for the minimum booking slot (the comparison is normalised to present the charges in euros/MWh) while in some cases the assessment may miss some taxes and levies or network connection charges.

128 The analysis reveals how seasonal access and storage costs hovered among MSs in the range of 1 to 3 euros/MWh in 2021. The costs are linked to the spread between seasonal products. In fact, as mentioned, some storage operators offer their capacity in connection to those spreads directly.

129 Auction fees might be supplemented by revenue reconciliation mechanisms. Summer-winter spreads tend to set reference prices for storage auctions. Figure 31 values can differ from actual storage costs in the first half of 2022 in selected MSs. For example, the inverted summer-winter spreads of the last few months have halved the prices of the capacity auctioned in France, hence SSOs requested a larger financial compensation.

Storages' role and importance across MSs

130 Storage sites are key both to securing mid-term supply to meet seasonal demand swings (and back supply in case of a disruption) as well as support short-term flexible system operation, and assist price management. Regulations governing storage access need to be assessed in view of these two roles. The sites' dimensions and their technicalities also affect the precedence of the roles. The case box below discusses the storage value strategies, as well as their impacts on hub pricing.

Storage value strategies and their impacts on hub pricing

Traders, producers and suppliers use underground storages as a key asset to flexibly manage volume and price risks. They do that in both short-term (i.e., days, weeks) and mid-term (i.e., months, seasons) timeframes. Storage users mainly use two storage valuation strategies:

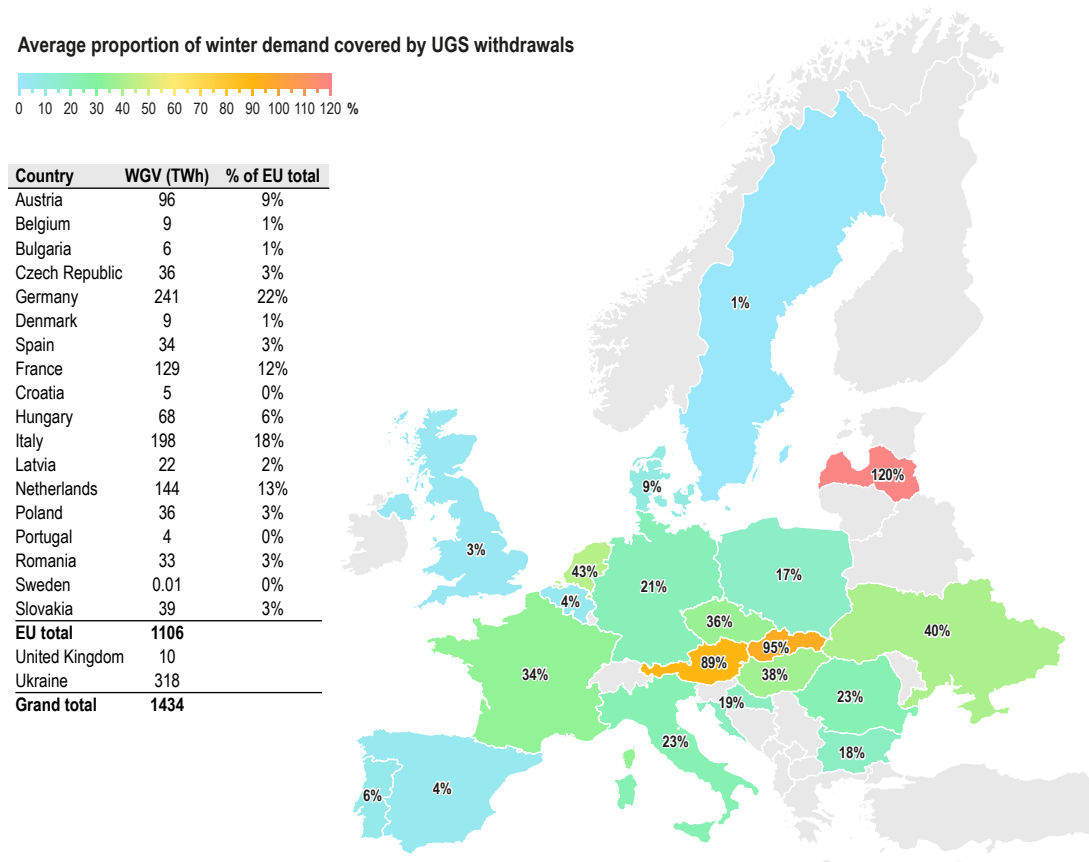
- Intrinsic value strategies refer to the value gained from the mid-term hedging of forward prices. The key reference to that hedging are the summer-winter seasonal spreads.
- Extrinsic value strategies refer to the value gained from short-term flexibility in storage use in response to current market developments. This generally applies to managing short-term price volatility, but also to the value gained from changes in the relative pricing of gas for forward products across the year.

In practice, both strategies are interrelated; market participants may initially book capacity and conclude trades to hedge seasonal spreads and physical needs, but then they might arbitrate between those contracts as they cascade, adding profitability from the external value positioning to the initial intrinsic positioning.

Demand for injecting gas into storages influences hub price formation across spring and summer months (i.e., storage injection season). On the other hand, the storage filling levels impact hub price formation in autumn and winter months (i.e., storage withdrawal season); low stock levels can contribute to upward pressure on prices (as was the case in 2021) while sufficient storage stocks can contribute to reduced price volatility. [Section 1.2.4.3](#) offers further considerations on the subject.

131 [Figure 32](#) compares the share of national winter gas demand met by storage withdrawals across the different MSs. While storage withdrawals cover on average 25% of EU winter gas consumption, the value amply oscillates per system. This assumption has to be corrected though, as the storage sites in a number of MSs (e.g., in Latvia or Austria) play a broader role and secure regional gas supply beyond the national boundaries. This regional dimension provides for higher ratios in the assessment.

Figure 32: Comparison of the average proportion of winter demand covered by storage withdrawals and Working Gas Volumes (WGV) by country – 2021 – % and TWh



Source: ACER calculation based on GIE and Eurostat.

- 132 The availability of storage is often determined by the presence of favourable geological structures to store gas. Thus, there are big differences in the availability of storage capacities across the EU, as Figure 32 shows. Moreover, the rest of the gas infrastructure granting supply flexibility to the system affect the significance of storages; in principle, MSs with lower relative spare interconnection and/or LNG regasification capacities, but also systems with larger seasonal demand variations, would find storage withdrawals to be more critical to meet winter demand, which could justify the introduction of storage obligations.
- 133 However, the correspondence is not straightforward and can be affected by other factors. For example, Figure 32 reveals that MSs without storage obligations in place (until 2022, e.g., the Netherlands, Germany, Austria or Czech Republic) tend to present larger withdrawal/demand ratios, which would refute the above reasoning. Hence, given that several factors are at stake, it is difficult to extract conclusions and isolate the drivers. For example, Gazprom controls relevant storage capacities in the four MSs mentioned and the storages are used to adjust regional supply nominations.
- 134 In that respect, a recent paper published by CEER calls to include long-term storage in the integrated network planning, based on scenarios that incorporate assumptions on the expected level of supply reliability for each MS⁸⁴. The share of electricity demand met by gas-fired power plants shall be included in the planning. In principle, MSs with a larger reliance on renewable power generation backed by gas plants would benefit from higher storage flexibilities.

84 The CEER paper maintains that the role of storage “largely differs from a country to another, according to their location on the gas chain, the seasonality of demand, their access to alternative sources of flexibility and also the characteristics of their underground geological structures”.

135 While the events of 2021 have reopened considerations about the need for strengthened storage regulations, those need to be carefully designed. Storage obligations add value by securing gas to hedge against supply disruptions, guaranteeing withdrawal capability, providing more certainty to operators (and the system) concerning bookings and revenues and, last but not least, putting some downward pressure on prices during tight supply scenarios, benefitting the broader market. However, they can also prevent market participants to respond efficiently to market signals⁸⁵ when supplies are abundant by limiting the choice across the available supply flexibility options or pressure summer prices up when meeting the filling targets.

136 Hence, storage regulations should be set prudently after assessing and adjusting to the specifics of each market, but also the expected supply scenario that may likely occur in the future. It is the prerogative of MSs to decide to set storage obligations or strategic reserves based on possible scenarios and their risk-assessment. Understandably, security of supply concerns are a key responsibility for national regulatory authorities. The CEER long-term storage paper assesses the *value of storage from a system perspective* and defends the introduction of certain types of regulatory interventions where competitive alternatives may not be sufficient. Regional cooperation and cross-border accessibility to storage is favoured, as it has the potential to increase welfare gains and use existing assets more efficiently.

Storage economics in 2021 and 2022

137 Summer-winter spreads, which primarily determine the financial appeal for mid-term UGS utilisation strategies, had been narrowing at EU gas hubs since 2010 (by means of example, they have dropped from 4 euros/MWh in 2012 to 1.2 euros/MWh for the 2015-2019 average, taking TTF as benchmark). This has resulted in the lower total demand and the higher supply flexibility options available in the market. The summer-winter spreads increased again in 2019 and 2020 – as [Figure 33](#) shows. However, the increase was chiefly an outcome of lower-than-average prices in summer months⁸⁶.

138 As amply discussed, the unprecedented market developments observed since mid-2021 have brought EU gas prices to record high levels. In parallel, the summer-winter spreads have become even narrower, reducing the financial incentive of using storages to hedge forward prices. Narrow seasonal spreads were distinctive in 2021 (1.6 euros/MWh on average), with the rapid escalation in prices across summer months eroding the price difference vis-à-vis the winter months. This is shown in [Figure 33](#), where the blue ex-ante seasonal spreads are assessed each March⁸⁷ for the period 2015-2023. The expectation of the markets by March 2021 was that EU gas prices would be more moderate across the winter months of 2021/2022, once the summer supply concerns had been resolved⁸⁸.

139 Yet, in 2022, the summer-winter spreads tightened even further, recurrently becoming negative (-18.8 euros/MWh when assessing them as the average of the month of March 2022). The reason is multifaceted. To start with, the EU storage stocks ended up at record low levels in Q1 2022, whilst the filling storage season opened in the context of elevated supply risks following the Russian invasion of Ukraine. Therefore, mandatory filling targets were set by law. As a result, summer 2022 prices rose due to both the market pricing summer contracts very high to guarantee physical flows as well as EU suppliers strongly competing to procure and inject gas into underground storages in order to meet storage obligations. The tense political climate was anticipated to persist across the whole summer 2022, and then gradually ease in winter, releasing some pressure on prices. Those combined factors explain the negative spreads. [Figure 33](#) tracks the summer-winter seasonal spreads and their evolution across the last six years.

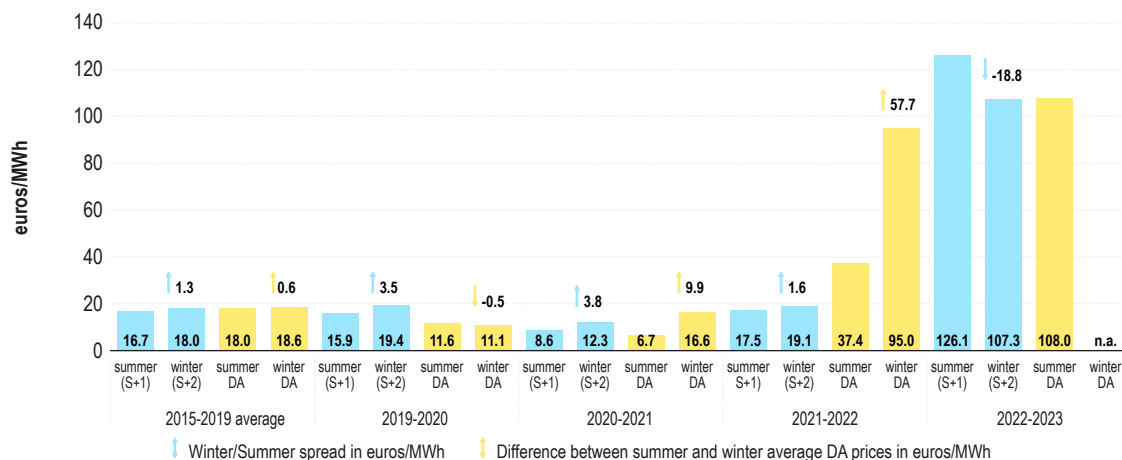
85 For example, the impossibility to withdraw gas already stored could result in importing volumes from a costlier origin, which could eventually set a higher marginal reference price at the hub.

86 E.g., Spreads were from 4 euros/MWh in 2012 to 1.2 euros/MWh in 2015-2019 average for TTF. In 2019 and 2020, spreads grew rather as an outcome of very depressed summer prices (record LNG, COVID-19related demand fall) instead of high price premiums in the winter.

87 While the assessment in March 2022 showed very tight prices (which also kept a lid on storage capacity prices in the Q1 2021 capacity auctions), seasonal spread volatility has also increased. Forward price estimates can be subject to rapid changes under the current stressed market conditions.

88 The clear deviation between the prices forecasted in March 2021 for both next summer and winter and the actual much higher spot prices registered on average across the season underscore how the market was not able to predict the drastic price escalation (driven by a geopolitical conflict).

Figure 33: Comparison of ex-ante season summer/winter spreads vs actual spot prices at the TTF hub – 2015 – 2021 – euros/MWh



Source: ACER calculation based on Platt's and ICIS Heren data.

Note: The ex-ante summer/winter spread is calculated as the difference between the Season-ahead+2 and Season-ahead+1 hub product prices, both negotiated in March. The actual summer/winter spread is calculated as the difference between the spot average prices along both seasons. A circumstance of note is that March 2022 prices were subject to extraordinary volatility in the aftermath of the Russian invasion of Ukraine.

140 Summer and winter prices readjusted across Q2 2022. In June 2022, contracts for delivery in winter 2022/2023 were, on average, at 5 euros/MWh premium to the prices for delivery across the rest of summer 2022. While, overall, both summer and winter prices remain at very high levels, several factors brought winter prices back to higher levels compared to the summer ones. These factors, among others, were the strong storage injections across the early months of summer 2022, which have brought storage stocks to the five-year average levels, as Figure 26 shows and hence slightly released some demand competition for the rest of the summer. This is supplemented by, the fact that winter season demand is higher than summer one and by the persisting uncertainty about Russian supplies together with the foreseen strong global competition for LNG next winter. Some uncertainties about nuclear production in France for next winter, as well as a share of German nuclear generation due to bringing offline some of the nuclear plants in the beginning of 2023 are also contributing factors.

1.2.4.3 Mid-term prospects of EU underground storages: striking a balance between security of supply and flexible system operation

141 The concerns about security of gas supply have magnified the gas securing role of gas storages. In that respect, the EC's proposal of March 2022 for a regulation on gas storage⁸⁹, has called to fill EU storage sites up to at least 90% of their capacity by 1 November each year until 2025 (with a threshold set at 80% for 2022). The proposal also requests MSs to follow a filling trajectory and measures to achieve the threshold. Solidarity principles but also the differences between the Member States in terms of relative storage availability compared to the national demand need to be taken into account when setting those trajectories.

142 Before that, the Hydrogen and Decarbonised Gas Market Package has emphasised in December 2021 the security dimension of storage sites. The legislative proposal called for Member States to delve into their security of supply assessments, including considerations about the adequacy of storage infrastructure. The package suggests a number of measures to diminish the security of supply risks, once detected. These measures include: a) introducing storage obligations in line with the internal market rules, b) tendering storage capacities with potential shortfalls in costs covered by the system, and c) setting up strategic stocks of gas. Moreover, proposal requests to specifically include the risks linked to the control of storage by entities from third countries, in clear reference to Gazprom's strategic behaviour of 2021, already discussed above.

143 In this context, a number of MSs already introduced extraordinary measures to increase their gas stocks.

89 See footnote 79. The proposal suggests additional points, such as the requirement of a regulatory authorisation to close storage facilities, and, crucially, the consideration of temporarily releasing transmission tariffs at entry and exit points of storage facilities to incentivise injections.

To cite a few, Austria and Germany, for example, have introduced storage regulations to increase reserves, Slovakia will introduce storage obligations, whilst in Latvia the injection season started in February instead of May. The Italian regulator was tasked with designing a contract-for-difference mechanism to hedge the risk of buying storage capacity under the negative summer-winter spread.

- 144 While security of supply aspects understandably attract a lot of attention today, storages will need to find an optimal balance between the security of supply and flexibility procurement market roles across multiple timeframes. Under diminished supply stress scenarios, storages are expected to keep assisting the management of prices. However, such scenario may not occur immediately and understandably the critical situation may last for a while.
- 145 The expectation is that, in the coming years, the transition towards a carbon-neutral economy will further intensify the importance of storage flexibility. In the long run, green hydrogen – through storage and offtake of renewable electricity production – will notably complement and increase the seasonal flexibility offered by underground storages today, altogether assisting the integration of energy systems and fostering energy price stability. As a result, over time, some of the current sites will be increasingly used to store methane to foster blue hydrogen production (while others may end up injecting carbon dioxide generated in carbon capture procedures⁹⁰). Faster cycle facilities, in particular salt caverns, are better suited to store green hydrogen produced by renewable electricity.
- 146 This more flexible role of gas storages will not only back the gas system, but will importantly facilitate the operation of the future EU power systems and a more integrated energy system. In the future, the EU power systems will require increased flexibility in order to balance the massive amounts of variable renewable generation that will grow in size and importance until 2040, while methane and hydrogen will store energy, given their potential to be transported and stored at a lower cost than large volumes of electricity.

90 Hydrogen storage may be feasible in geological formation and is being researched.

2. Assessment of EU gas markets according to Gas Target Model metrics

147 The EU internal gas market has progressed in the past years, building on the enhanced functionality of gas trading hubs and the reinforced accessibility between national markets. Those two elements are the pillars of the Gas Target Model, and are both assisted by the proper implementation of gas Network Codes. The AGTM has improved the integration and competitiveness of national gas markets, delivering benefits to European end consumers. That outcome was first visible in the North West region, but has also advanced in various other jurisdictions. However, the gradually increasing gas scarcity in the market from the second half of 2021 and through the first half of 2022 has revealed a number of vulnerabilities. (The case box in [Section 1.1.3](#) discusses those and relates to the rising EU exposure to hub prices). Consequential to the relative scarcity of gas volumes in the EU gas market opened debate primarily on how to improve security of supply and reduce dependency on the Russian gas and whether the market design can support this endeavour.

148 Integral to the AGTM is a set of indicators called market health and market participants' needs metrics. They are respectively used to assess market structures and transactional activity of the EU hubs. Those indicators help to measure the progression of the internal market construction. The target thresholds and specific values of these indicators are analysed in this chapter.

2.1 Assessment of EU gas markets health and gas supply sourcing cost

149 In the context of the AGTM, structural competition aspects are covered by the term 'market health'. The market health metrics measure the number and concentration of supply sources as well as the possibility to meet demand, building only on supply sources not controlled by the largest upstream supplier. Previous editions of the MMR analyse all these metrics⁹¹ in depth. This year, the assessment focuses on the indicators that measure MSs' diversity of supply, including those that highlight the dependence on Russian gas. The Section starts by looking at evolution of gas sourcing costs.

Gas sourcing cost

150 The cost of the gas that wholesale market participants purchase varies per company and period, subject to the sourcing mechanisms (i.e., LTCs versus hub direct purchases), the specificities of the contracts and the employed hedging strategies.

151 Traditionally, more intense procurement activity at trading hubs - together with higher supply diversification - resulted in lower gas supply sourcing costs⁹² but at the same time the procurement was committed for shorter timeframes. Market developments of 2021 and 2022 made direct hub purchases costlier than long-term supply contracting, depending on the individual contracts' price formulas⁹³. These developments considerably amplified the differences in average sourcing costs between MSs, but also between the distinct supply sourcing mechanisms per country.

152 ACER recurrently estimates an average annual theoretical gas supply price per MS based on a methodology that considers three main types of gas sourcing costs and that makes use of the following inputs: i) an explicit basket of hub products (in markets with sufficient forward products transactional activity), ii) declared cross-border imports and iii) domestic production prices⁹⁴.

91 See the ACER MMR data portal CHEST, which reports the values of supply concentration and Residual Supply index indicators in the past years.

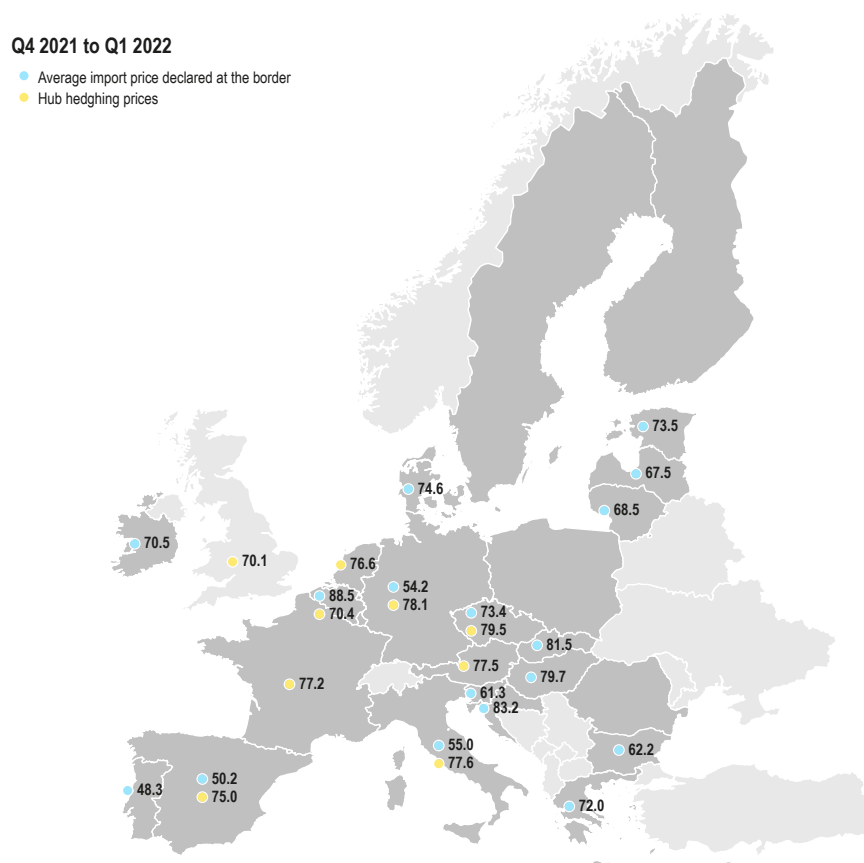
92 Sourcing costs are also affected by factors other than upstream competition and liquidity. For example, lower prices are observed occasionally at MSs with prevailing oil-indexations under certain favourable conditions, even if they are not that competitive in terms of number of market participants.

93 Gas sourcing prices were also affected by demand drivers (i.e., whether demand was more or less elastic) as well as the role that storages might have played.

94 See MMR 2015, Annex 6 for details on the general methodology and specific data used for selected MSs.

- 153 For 2021, the assessment shows that gas supply sourcing costs rose by more than 25 euros/MWh on EU average in comparison to 2020. The increase was more than 40 euros/MWh on average, comparing 2020 against Q4 2021 and Q1 2022. In turn, the sourcing price differences between MSs were significantly larger. For example, while in 2020 the largest difference was 5 euros/MWh, in 2021 it was 15 euros/MWh (and 35 euros/MWh when considering the period from Q4 2021 to Q1 2022).
- 154 The climbing gas sourcing costs resulted in a substantially higher gas import bill for the EU. According to EC estimates EU gas imports totalled 131 billion euros in 2021⁹⁵. This is a rise of 90% in comparison to the 70 billion bill of 2019 - pre-COVID-19 'normal' levels – and 250% increase vis-à-vis the 37 billion spent in 2020. The magnitude of this rise (i.e., circa 100 billion euros last year) underlines what impacts higher gas prices had on end consumers, a point to be argued further in the ACER Retail MMR.
- 155 Figure 34 shows the price estimates for the individual MSs and the distinct types of sourcing mechanisms. In view of the significant price increase observed across the period, this year's analysis has been divided into two periods. Figure 34 shows the price estimates for the average of Q4 2021 and Q1 2022, while the analysis for Q1 to Q3 2021 is presented in [Figure v in Annex 1](#). Gas import price data are available in Eurostat Comext database, although not all MSs are reported.

Figure 34: Estimated average suppliers' gas sourcing costs at selected MS – Q4 2021 – Q1 2022 – euros/MWh



Source: ACER calculation based on Eurostat Comext, ICIS and NRAs.

Note: Import prices for Austria, Netherlands, France, Finland, Romania and Poland could not be assessed.

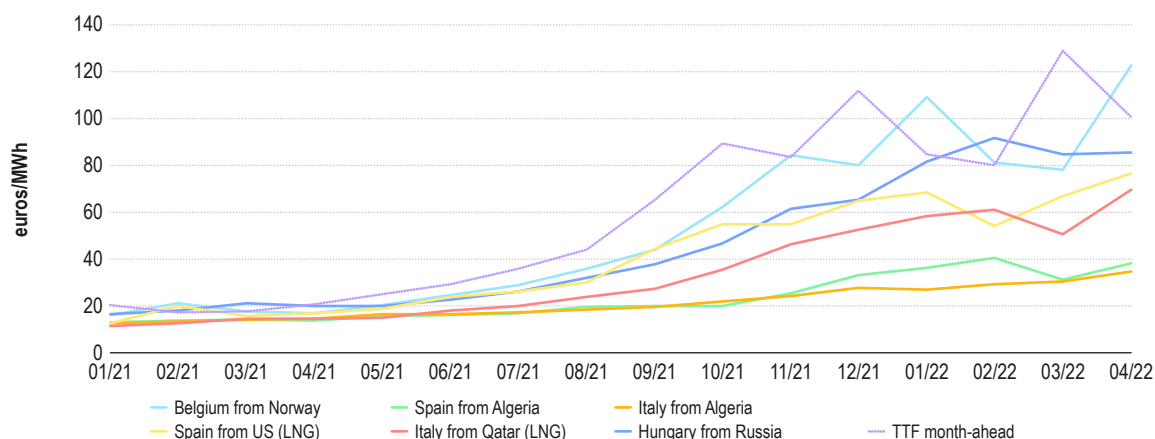
- 156 Figure 34 underlines the substantial differences in gas sourcing cost across MSs. The modelled sourcing cost of procuring gas directly at hubs were relatively similar across markets, in view that EU hubs' price rises were rather uniform (and notwithstanding some growing hub price differences since 2022, discussed in [Section 1.1.4](#)). However, the average gas import prices declared at the border showed a considerable variation, depending on the price formulas employed in the long-term supply contracts per each MS. (The figure considers the weighted average price by volume for the declared gas imports.) It is to be noted that EU gas suppliers tend to hedge the prices of their long-term supply contracts using

95 See the EC quarterly gas market monitoring report for more details.

hub products (suppliers tend to hedge as well the price of the gas that they sell to final consumers). As such, while Figure 34 assesses the average import prices paid for long-term gas supplies across 2021 and 2022, suppliers might have faced higher final sourcing costs resulting from their hedging activities. ACER was not able to model those hedging costs, which vary per contract and company.

- 157 Figure 35 compares the price evolution of a selection of long-term supply contracts making use of Eurostat Comext reported data. The analysis reveals how Norwegian supply was reported significantly more expensive than Algerian supply, in view of the larger (spot) hub indexation used for the former. Algerian contracts are in turn deemed to still contain high shares of, time-lagged, oil-price indexations. Russian supply as well as Qatari and US LNG imports also became increasingly expensive over this period.

Figure 35: Estimated prices of long-term supply contracts at selected MSs from selected supply origins – euros/MWh – 2021 – April 2022



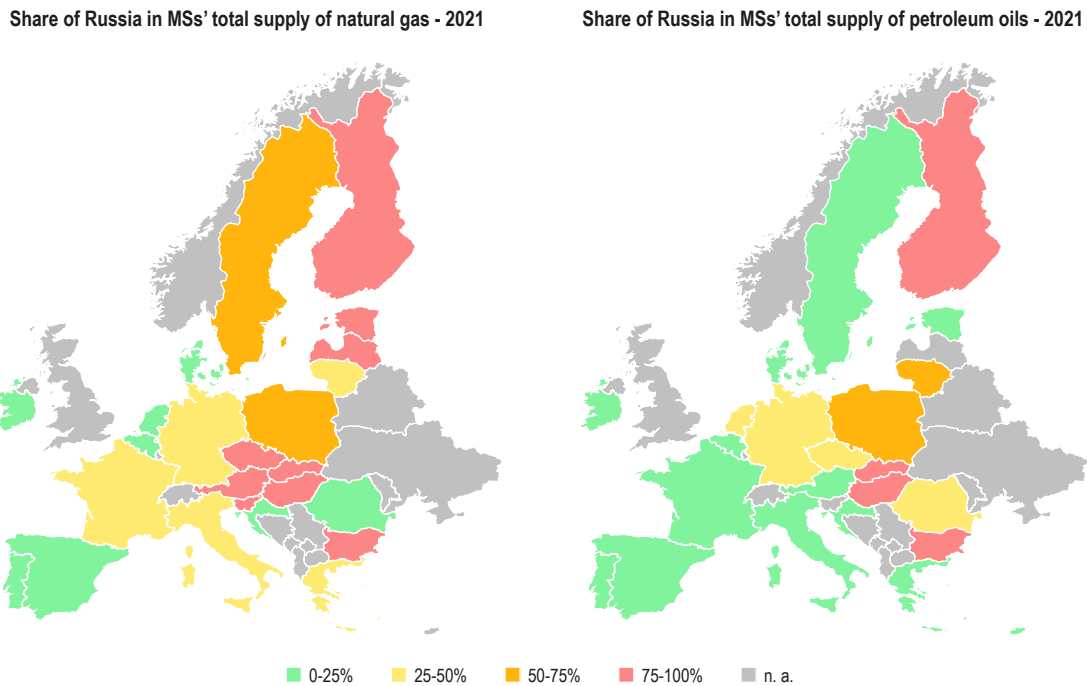
Source: ACER based on Eurostat Comext

Note: While Eurostat Comext data estimates the average prices of long-term supply contracts, EU buyers might have faced higher final sourcing costs resulting from their associated hedging activity. ACER was not able to model LTCs' hedging costs.

Number of sources of gas supply

- 158 As discussed in Section 1.1.2, the markets restored the supply balance throughout the year through changes in the supply shares from the various geographical sourcing regions. Those shifts intensified in the first half of 2022, amid reduced Russian flows and/or the decision of certain MSs to halt Russian gas imports.
- 159 The EU dependency on Russian gas supply has attracted a lot of attention after Russian gas volumes were reduced. To recall, EU buyers acquire Russian-sourced gas either directly (via long-term bilateral contracts and/or via Gazprom's sales at hubs) or indirectly (by Russian gas being resold by a third party at an EU gas hub). Figure 5 analyses the supply portfolio of the EU and UK in 2021 and the first half of 2022, showing that gas of Russian physical origin covered respectively for 31% and 20% of their combined demand (in addition, LNG of Russian origin covered for an additional 4%). Figure 36 in turn, details the reliance per MS on the gas of Russian physical origin (the figure also analyses supply dependency on Russian oil.) Central-East and Baltic MSs showed the highest reliance on Russian gas in 2021.

Figure 36: Share of Russian physical gas and oil in total supply of individual MSs – 2021 – % in ranges

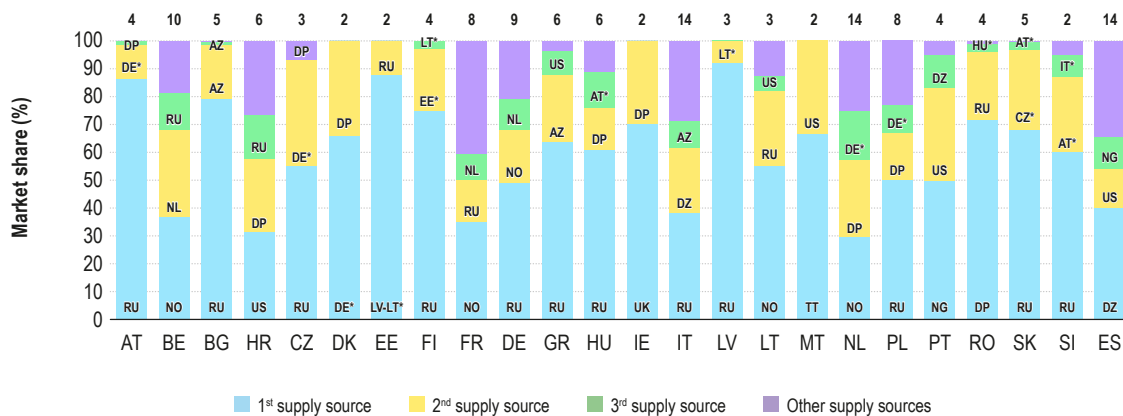


Source: ACER based on Eurostat data.

Note: The assessment considers to what extent the share of Russian originated gas meets the final demand of a MS, and considers gas imports of other origins as well as domestic production.

160 The physical geographical origin of the gas might partly differ from its contractual origin. The contractual origin refers to the country where the gas was contracted by the supplier (EU gas suppliers must declare to national custom offices the contractual origin of their gas imports). Figure 37 examines the gas supply share by contractual origin at each MS in 2021. The main difference between Figure 36 and Figure 37 is that the latter considers as a distinctive supply contractual origin individual EU (liquid) hubs; for example, Austrian customs offices report that 15% of the country demand was supplied with gas contracted in Germany in 2021, while according to Eurostat data, Russian physical gas amounts to 75% to 100% of Austrian gas supplies. This means that most of the gas contracted in Germany was of Russian physical origin.

Figure 37: Estimated number and share of supply sources in terms of the contractual origin of gas in selected MSs – 2021 – % of actual volumes purchased⁹⁶



Source: ACER calculation based on Eurostat and Eurostat Comext.

Note: D.P stands for domestic. Russian flows into Belgium, reported by Eurostat, could be subject to subsequent diversion as a result of the LNG transhipment agreement at the Zeebrugge Terminal⁹⁷. The French data covers 2020.

96 The metric looks at the geographical origin of the sourced gas and not at the number of distinct interconnection capabilities. Both figures may differ for selected MSs.

97 Fluxys has signed a deal with Yamal Trade that allows Russia's specialized ice-breaker LNG carriers to transfer Yamal LNG plant volumes to Zeebrugge into conventional LNG vessels, to allow regular onward shipments to Asia-Pacific and Middle Eastern markets.

161 [Figure 37](#) shows how Russian, Norwegian and Algerian and Azerbaijani pipeline supplies, as well as liquefied gas imports from a variety of origins, have a distinct presence across individual MSs. This is because the supply at the various EU regions is shaped by different geographic, infrastructural and contractual frameworks. Supply volumes changed in 2021, in comparison to 2020. The most relevant shifts were the increased North African pipeline flows into Spain and Italy, the rising share of Azerbaijani gas directed into Italy, Bulgaria and Greece and the rising flows from US LNG to Spain, France and the Baltics. Conversely, the supply share of gas produced in the EU has decreased.

2.2 Assessment of the EU gas hubs well-functionality degree

2.2.1 Overview of trading activity at European gas hubs

162 The gas volumes traded at European hubs remained on average at quite similar levels in 2021 compared to 2020, breaking a six-year upward trend. Trading activity varied across quarters though; higher demand, increasing prices and rising volatility somewhat backed trading activity in the first part of the year⁹⁸, as traders revised their hedging positions. However, in the last part of 2021 and the first months of 2022 the record-high prices and the general high-risk trading environment forced market participants (and particularly those of smaller size) to limit their trades (-7% YoY in Q4 2021 and -6% YoY in Q1 2022⁹⁹). Traded volumes particularly dried out for forward contracts, amidst caution not to take long-term positions in a very unstable environment. ([Figure 7](#) offers an overview of the variability of forward prices since Q4 2021.) The more stringent financial requirements and the difficulties to meet collateral and margin call requirements became for traders at increased market prices, the more hub liquidity dropped.

163 As argued before, less flexible spot LNG supplies as well as reduced EU domestic gas reached EU hubs during most of the year. Both supply sources tend to nurture hub (supply-side) liquidity in the EU. As a result and in view of increasing prices, the buyers of long-term supply contracts intensified the direct offtakes of gas. Thus, they also reduced volumes in the hub as well as offered fewer surplus volumes for direct hub-sales. Conditions were made worse by the limited gas offers by Gazprom both at EU hubs and at its dedicated trading platform¹⁰⁰.

164 Liquidity migrated from the broker-executed OTC markets towards exchange executed markets, chiefly from Q4 2021. Those participants continuing to trade show a preference to cover their positions at exchanges, where volumes are supervised and cleared by central market operators that cover credit default risks. As an illustration, OTC traded volumes fell by more than 50% across Q4 2021, while exchange volumes rose by 40%. (By way of example, exchange executed trades accounted for 70% of total traded volumes in TTF in Q4 2021, in contrast of 40% in Q4 2020.)

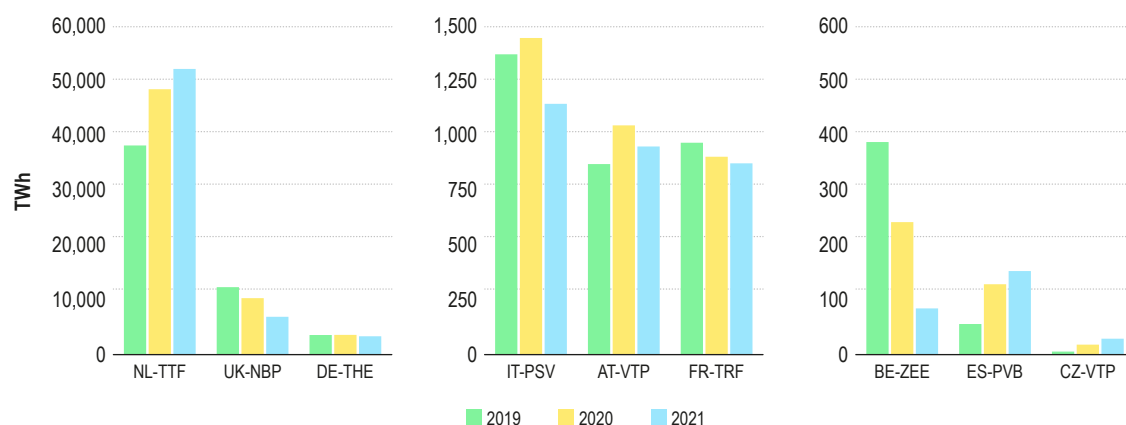
165 At any rate, the volume of gas traded at EU and UK hubs was 12 times higher than their final gas consumption in 2021. As [Figure 38](#) illustrates, the Dutch hub TTF further consolidated its position as the European trading benchmark. TTF's 2% rise in total traded volumes served to offset the declines registered at the majority of other European gas hubs.

98 Across Q1 and Q2 2021 traded volumes slightly dropped YoY, the lower injections on storages arguably a driver for that, whilst in Q3 2021 volumes sizeably rose by 20% amid rising prices, at the same time when trade started to shift from OTC markets into exchanges.

99 While increased price volatility tends to trigger both speculative trading and hedging activity, the high price environment ended up pricing out numerous counterparties, whilst leaving those remaining increasingly risk averse.

100 See [footnote 28](#).

Figure 38: Traded volumes at EU and the UK hubs – 2019 – 2021 – TWh/year



Source: ACER based on REMIT, Trayport and exchange operator data.

- 166 TTF keeps acting as a price and market referential in Europe. The total gas volumes traded at the Dutch hub account to twice more than the sum of volumes traded at all other European hubs. The Dutch hub has clearly consolidated its position for hedging most continental forward volumes, and is increasingly used as a preferential trade venue to arbitrate global LNG supplies.
- 167 The British NBP hub continued to decline in 2021 for the seventh year in a row. Cross-border trading activity was in part influenced by Brexit; while no critical regulatory or cross-border trading barriers have emerged since the UK left the EU¹⁰¹, Continental market participants find it easier trading in euros than in pounds, whereas they may as well prefer avoiding potential complications related to technical rules, licensing or customs declarations. As a result, NBP trading has become more regional, even if from Q2 2022 NBP has seen increasing interest from EU buyers to acquire LNG as presented in [Section 1.1.4](#). The fall of NBP's relevance has also affected the Belgian ZEE-hub which is closely linked to NBP and is sterling-denominated. The ZEE-hub has yet again reported declining volumes across 2021. Both hubs have kept dropping in the past years, partly driven by the expiration of the legacy capacity contracts on the IUK interconnector that connects the UK and Belgium. The price spreads generally remained below transportation tariffs, limiting price arbitrage trade except in Q2 2022 when LNG exports from the UK were supplied into the EU and spreads amply exceeded reserve prices at interconnection points.
- 168 The gas volumes traded at the newly formed German Trading Hub Europe (THE) exceeded those negotiated at NBP in the last months of 2021. The merger of the two former German hubs, NCG and Gaspool, went live on October 2021. The new hub was called to gradually increase its relevance in the years to come, as a likely outcome of the growing transit role of the country. However, that role cannot be accomplished with the same means after the Russian invasion of Ukraine and the decision to diversify away from Russian supply. The hub liquidity could be further supplemented by the new LNG terminals planned to operate from end-2022 and 2023. Germany has the biggest gas demand and the largest storage capacity in the EU area. These factors could contribute to THE's liquidity growth, while its relative regional growth may be also backed by the falling production at the Groningen field. 2021 was not a changeover year nevertheless: the total traded volumes at the merged THE hub fell in Q4 2021 compared to the sum of the formerly distinct NCG and Gaspool hubs in 2020, mainly driven by the high-price risk environment¹⁰².

101 See for example an overview of the impacts and mechanisms of cross-border gas trade in [this guide](#).

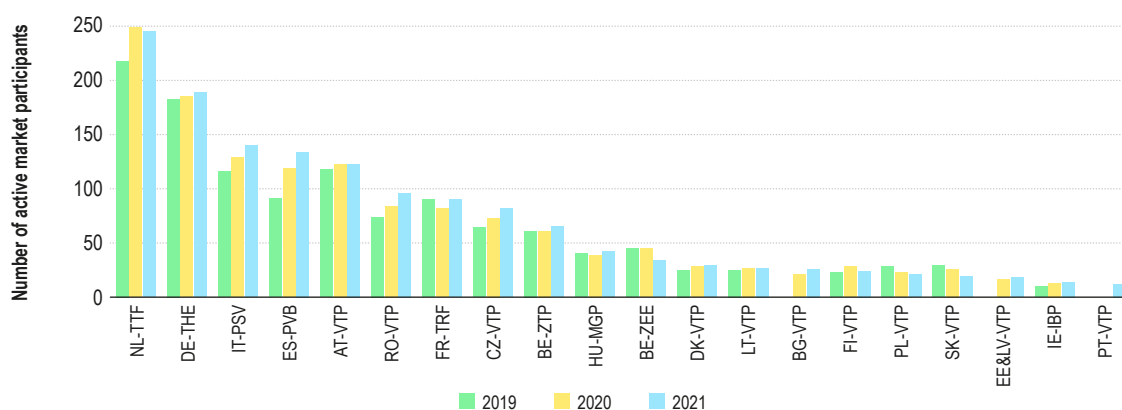
102 The drop was supplemented by a number of specific factors, such as the subdued Russian supply via Yamal, the dropping German industrial demand, the rapidly decreasing storage stocks and, last but not least, some larger LNG volumes contracted and reaching Germany from other NWE hubs.

- 169 Trading activity also fell on annual average in Italy and France, with large decreases in Q4 2021 (25% and 6% respectively) as trading with annual contracts was shrinking. Beyond the overall high-risk price environment, factors such as weather, LNG deliveries, seasonal spreads (and related to them, storage auctions) or the nuclear woes in France moved liquidity up and down across different weeks. Contrary, liquidity in the Spanish hub PVB sharply increased YoY (and by 40% in Q1 2022), with the expiry of long-term contracted flows from Algeria via Morocco and the related rise in LNG arrivals supporting trading activity of forward products.
- 170 Hub-traded volumes also declined in the Central and Eastern markets of Austria, Poland, Czech Republic and Slovakia. In addition to the general reasons already mentioned, the hubs were specially affected by the uncertainty and the declining Russian flows transited across Ukraine and Yamal. The exception was Hungary. The rise in Hungarian hub liquidity in 2021 was driven by the enhanced interconnectivity of the market and the new supplies reaching across Turk Stream and also the Croatian Krk LNG terminal. Hungarian liquidity has also been falling, however, since Q4 2021 and across 2022¹⁰³, as the supply crisis intensified.
- 171 There were some positive developments in the group of ‘illiquid’ hubs. Hub trading activity began in Greece in Q1 2022, with a focus on spot and balancing products. Trading at the Bulgarian Balkan Gas Hub was also increasing throughout the year, with more volumes being made available via the gas release programmes. New pieces of infrastructure like the Gas Interconnector Greece-Bulgaria and the forthcoming new LNG terminal in Greece, coupling with the aim to diversify supply away from Russia are expected to further assist trading activity. Liquidity in the Baltic region has also been increasing since the liberalisation of the Finnish market and the inclusion of products delivered at the Finnish hub in the regional GET Baltic exchange, in addition to the merger of the Estonian and Latvian markets. Section 2.3.1 offers a case study about the evolution of GET Baltic hub trade in the last few years. The Iberian hub Mibgas has also started offering products for delivery at the Portuguese VTP in Q1 2021.

Market participants

- 172 Liquidity and competition of individual hubs are driven by, among other factors, the number of total active participants, benchmarked in Figure 39. The hub with the largest number of active market participants in 2021 was TTF, followed by the German THE. Noticeably, there were fewer market participants active at various hubs as the high-risk environment and the larger collaterals forced certain market participants to cancel their trading activity. The largest drops were reported at the Belgian ZEE and Slovak hubs.

Figure 39: Estimated number of market participants – 2019 – 2021 – count of active market participants



Source: ACER estimate based on REMIT data.

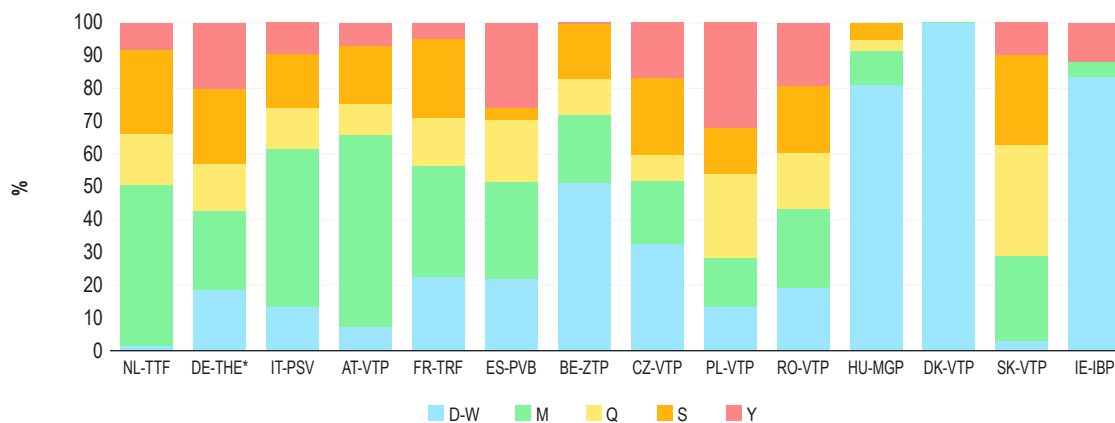
Note: Estimated based on registered users with at least one trade of standard contract for delivery at relevant VTP during the year.

103 MMR 2020 included a case study that discussed the broader market developments and the regulatory provisions that have backed the liquidity and competitiveness progression of the Hungarian gas hub in recent years.

2.2.2 Breakdown of traded volumes per hub product

173 Figure 40 shows the relative share of the different hub products traded at EU-organised markets in 2021, in accordance to the volumes transacted. On average, contracts for monthly and then for seasonal delivery represent the largest share. In both cases, most of the trades focus on front-products.

Figure 40: Breakdown of traded volumes per product type at EU hubs – 2021 – % of traded volumes



Source: ACER estimate based on REMIT data

Note: Product acronyms stand for: Y years, S seasons, Q quarters, M months, D_W refer to day-ahead and within-day.

174 Beyond their role to assist the supply portfolio over monthly horizons, month-ahead products attract a relevant share of speculative trading, involving financial market participants. The growing use of the month-ahead products in the price formulas of long-term hub-indexed contracts supports the use of month-ahead products in risk-hedging strategies. Seasonal hub products serve in addition to cover the summer and winter positions, and are closely linked to underground storages' operation as discussed in Section 1.2.4.2. The decision to enforce storage obligations for the forthcoming winter(s) reshaped the summer/winter spreads, with summer prices becoming higher than winter ones (see Figure 33). The obligations partly dried liquidity of some seasonal products in Q1 2022, in spite the significant financial assistance offered by some MSs.

175 The total volumes traded by means of year-ahead products fell in comparison to 2020. As discussed, the record-high prices and the extreme volatility deterred long-term trade, to avoid undue potential exposure. (e.g., In Germany they fell by 50% YoY in Q1 2022.) The relative share of these products differs in relation to the hubs' liquidity depth: established and advanced hubs show higher relative percentages than emerging and illiquid ones¹⁰⁴ where year-ahead products are not available for trade. Yearly contracts maintain a large relative share at the Spanish, Polish and Romanian hubs, a result of either local market specificities or legal obligations. E.g., in the two former markets, annual products are auctioned at the exchange, as a mechanism to release gas from incumbents, but make up a relatively modest share of traded volumes elsewhere.

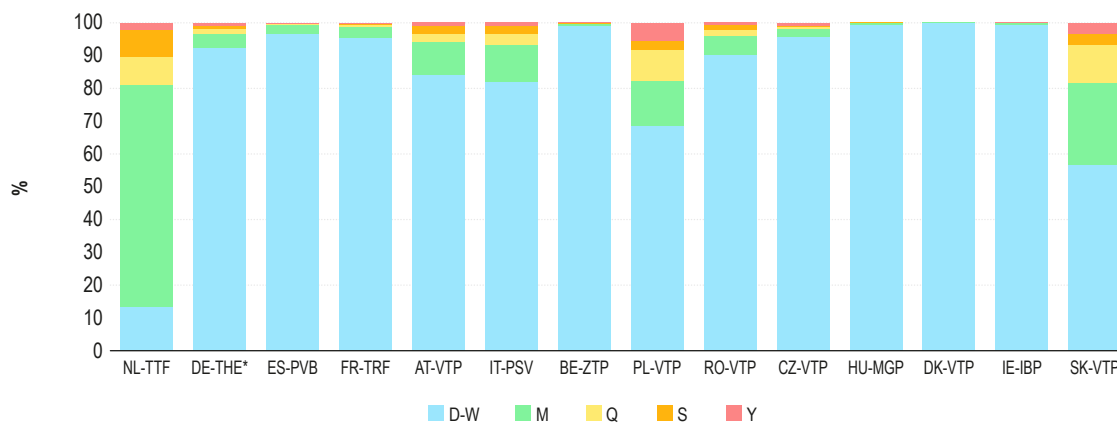
176 As it will be scrutinized in the next Volume of the Retail MMR, certain final gas and power consumers were more exposed to dynamic tariffs – along with those retailers that were insufficiently hedged – and hence, they were more impacted by the increasing spot wholesale energy prices in 2021. That situation has opened discussions to introduce more stringent hedging requirements to energy retailers, in order to better cover their exposure. This setting could contribute to backing the liquidity of year-ahead products in the years to come.

177 Within-day and day-ahead products are mainly used for physical portfolio optimisation close to delivery, short-term price arbitrage and/or balancing purposes. Again, their relative share is influenced by the liquidity of hubs. For example, day-ahead and within-day products make up the smallest share of overall traded volumes at the TTF hub in relative terms, while they cover for most traded volumes at various emerging and incipient hubs.

104 Figure 49 in the Section 2.3.1 will present the hub categorization.

178 Figure 41 shows the relative importance of the different types of products by number of trades. It demonstrates that, with the exception of TTF, market participants most frequently trade spot products, even if, as analysed, these products represent a relatively small share of the total traded volumes in view of their shorter duration.

Figure 41: Breakdown of the number of trades per product type at EU hubs – 2021 – % of total number of trades



Source: ACER estimate based on REMIT data.

2.2.3 Liquidity and competition at spot and forward markets

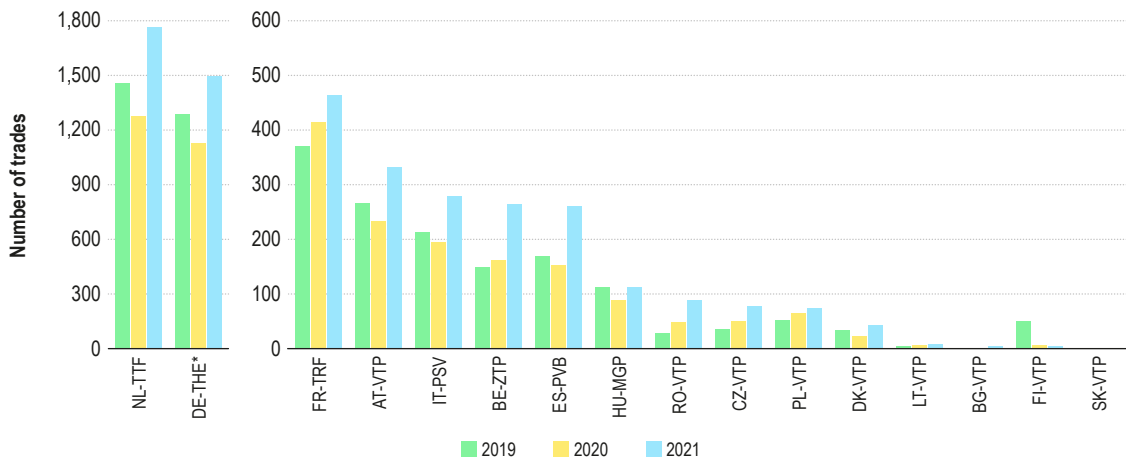
179 This section analyses the liquidity and the competitiveness of EU gas hubs based on the results of the AGTM hub well-functionality metrics¹⁰⁵. Hub spot markets are analysed first, followed by an overview of results related to hubs’ forward markets.

Spot markets

180 The number of spot trades (assessed here by looking at day-ahead products) increased at many EU hubs in 2021 compared to 2020. The outcome was a consequence of the higher gas demand in the first half of the year, as spot markets – the last traded timeframe before delivery – are very responsive to actual demand changes. The more volatile prices across trading seasons also prompted market participants to revise their positions more frequently. However, spot liquidity fell in the second half of the year (as well as the spot bid-ask spreads rose) chiefly in view of the lower gas demand, including power generation. TTF showed the highest trading frequency (see Figure 42). Other EU hubs with strong spot trading frequency included the German hubs and the French TRF, but also the Italian and Spanish hub, as spot trading activity tends to correlate with absolute demand (the weight of gas-fired power generation being a particularly important factor).

¹⁰⁵ Liquidity has been assessed with indicators measuring products, trading frequency, bid-ask spread and hub trading horizon, amongst others. Competition has been gauged with an indicator measuring the concentration of market participants related to volumes of concluded trades in different timeframes.

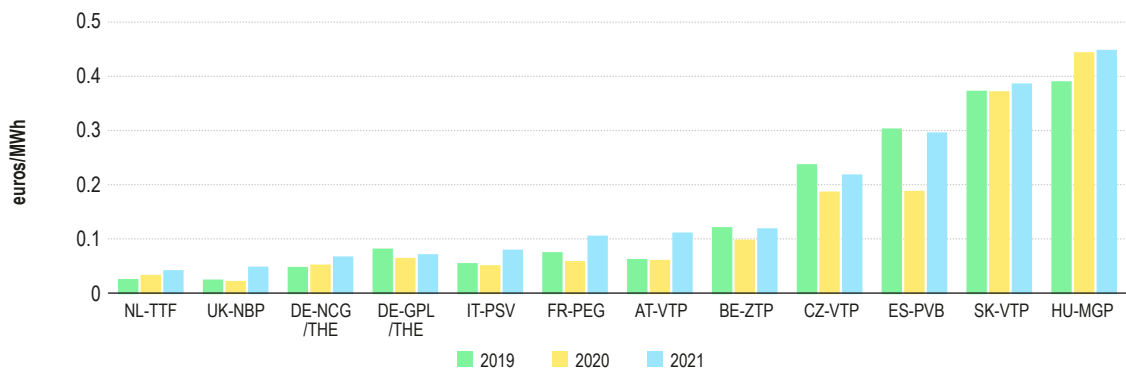
Figure 42: Spot markets trading frequency – 2019 – 2020 – average weekday number of trades of the DA product (two scales)



Source: ACER calculation based on REMIT.

181 Figure 43 shows the evolution of the spot bid-ask spreads in absolute terms across EU hub spot markets. Bid-ask spreads tend to be independent of the actual price of gas, as they represent the margins that the counterparties are asking for concluding a buy/sell operation more than the actual price of the commodity. Hence, when expressed as a percentage of the final gas traded price, the bid-ask spreads drop YoY, in view of the record-high prices achieved in 2021. However, the average spot bid-ask spreads increased in all of the assessed hubs in absolute terms, possibly as a result of price volatility increases. In particular, in less liquid markets, some traders may avoid open positions in periods of high volatility what may move bid-ask spreads up.

Figure 43: Bid-ask spread of EU hub spot markets – 2019 – 2021 – euros/MWh

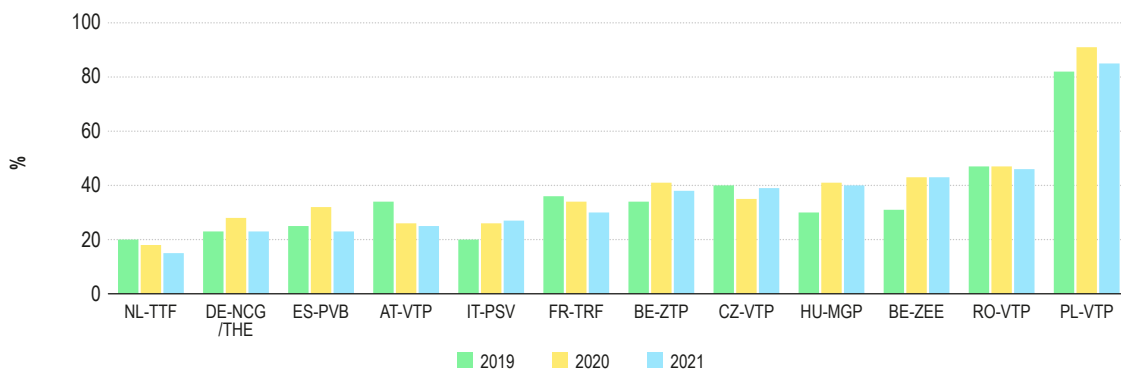


Source: ACER calculation based on ICIS data.

Note: The bid-ask spread is the difference between the prices available in the order book for an immediate sale (offer) and an immediate purchase (bid) of a physically settled gas product. The size of the bid-offer spread is a measure of transaction costs and liquidity. The lower the bid-ask spread, the lower the transaction costs and the higher the liquidity.

182 The concentration of spot traded volumes remained consistent with preceding years. In general, a correlation between liquidity levels and concentration was observed, with the most liquid spot hubs exhibiting the lowest combined market share of the major three market players, as shown in Figure 44. While the selling activity of Gazprom was lower, it does not have a significant impact on the aggregated values, presented in Figure 44 as the sum of the share of the three main market participants.

Figure 44: Spot market concentration – 2021 – CR3 % for concluded DA trades



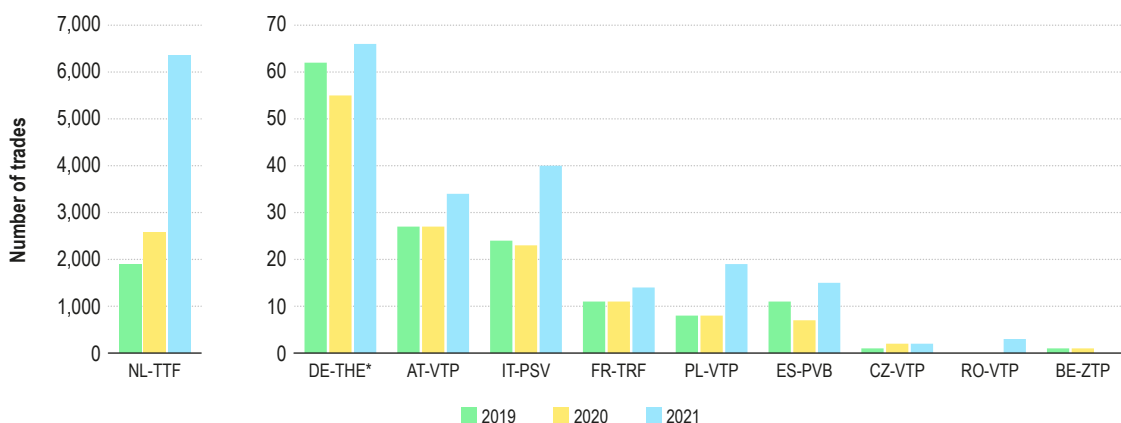
Source: ACER calculation based on REMIT.

Note: CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was higher.

Forward markets

183 Liquid forward markets are scarcer than spot ones. While a number of NWE hubs show a certain degree of forward liquidity, most of the EU's gas forward and futures trading activity has been concentrated at the TTF hub. That trend continued in 2021, with TTF amounting to more than 70% of the total forward traded volumes across the EU and UK (5 percentage points more than in 2020). The trading frequency of the month-ahead product, used as a benchmark to assess the AGTM metrics, increased substantially at TTF YoY, and increased more moderately at the other EU hubs ACER analysed.

Figure 45: Forward markets trading frequency – 2021 – 2019 – average weekday number of trades of the MA product (two scales)

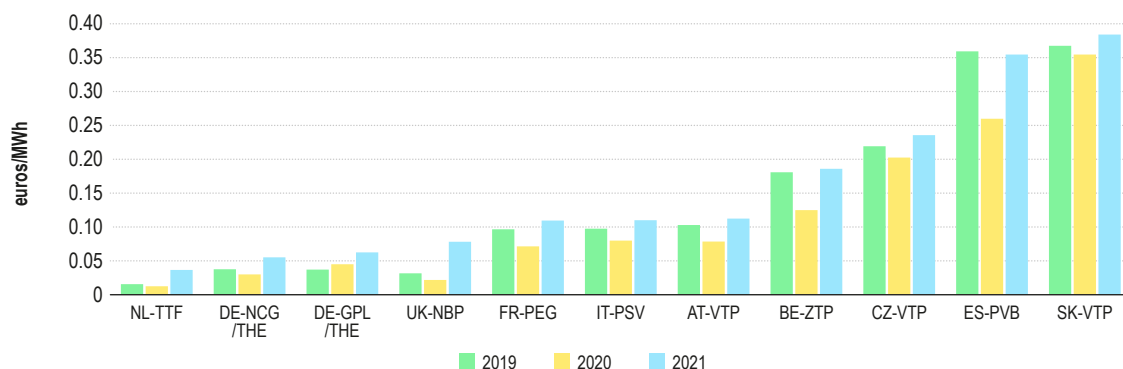


Source: ACER calculation based on REMIT data.

184 Despite their possible physical exposure in other markets, traders and shippers throughout Europe, as well as LNG producers, clearly favour TTF as the venue for taking forward positions due to its much higher liquidity that extends to products being delivered several years ahead. Such hedging strategies have been possible due to the high levels of price correlation and price convergence of EU hubs' spot prices. The rising spreads appearing from Q1 2022 between TTF and UK and France or Spain have not visibly altered the relative positions, although forward liquidity has improved (for example, YTD 2022 liquidity in the French TRF is 50% higher YoY).

185 Outside of the TTF hub, trade of forward products is driven by local market dynamics and often influenced by gas storage aspects or the availability or scarcity of LNG inflows.

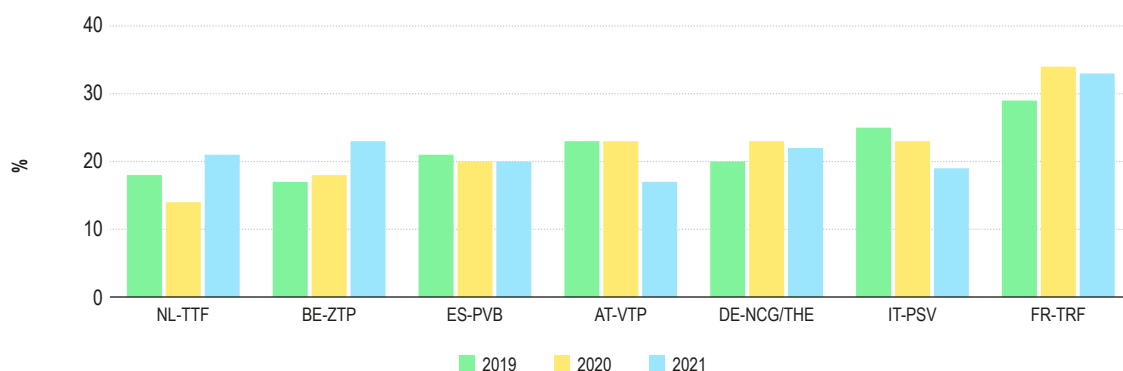
Figure 46: Bid-ask spread of EU hubs forward markets – 2019 – 2021 – euros/MWh



Source: ACER calculation based on ICIS data.

186 With regard to forwards trade, concentration remained in line with the levels observed in the preceding years. Forwards concentration shows slightly higher values compared to spot ones, although the case is country specific.

Figure 47: Forward market concentration – 2021 – CR3 % shown as a range for concluded MA trades

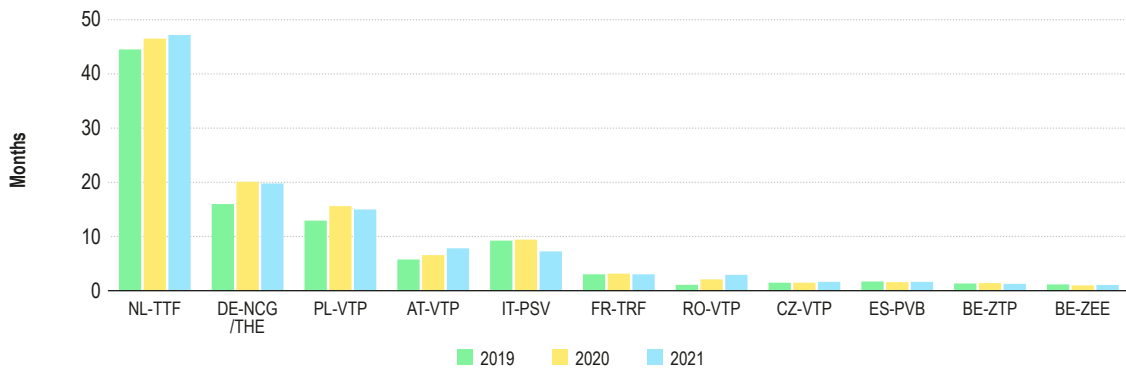


Source: ACER estimate based on REMIT data.

Note: Based on the market for the month-ahead product. CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was higher.

187 The trading horizon measures how far into the future traders can hedge their positions at individual hubs, considering a sufficient threshold on average trades. Like in previous years, the forward trading horizons were largest at the established hubs.

Figure 48: Hub trading horizon – 2019 – 2021 – average horizon in months for minimum 8 daily trades

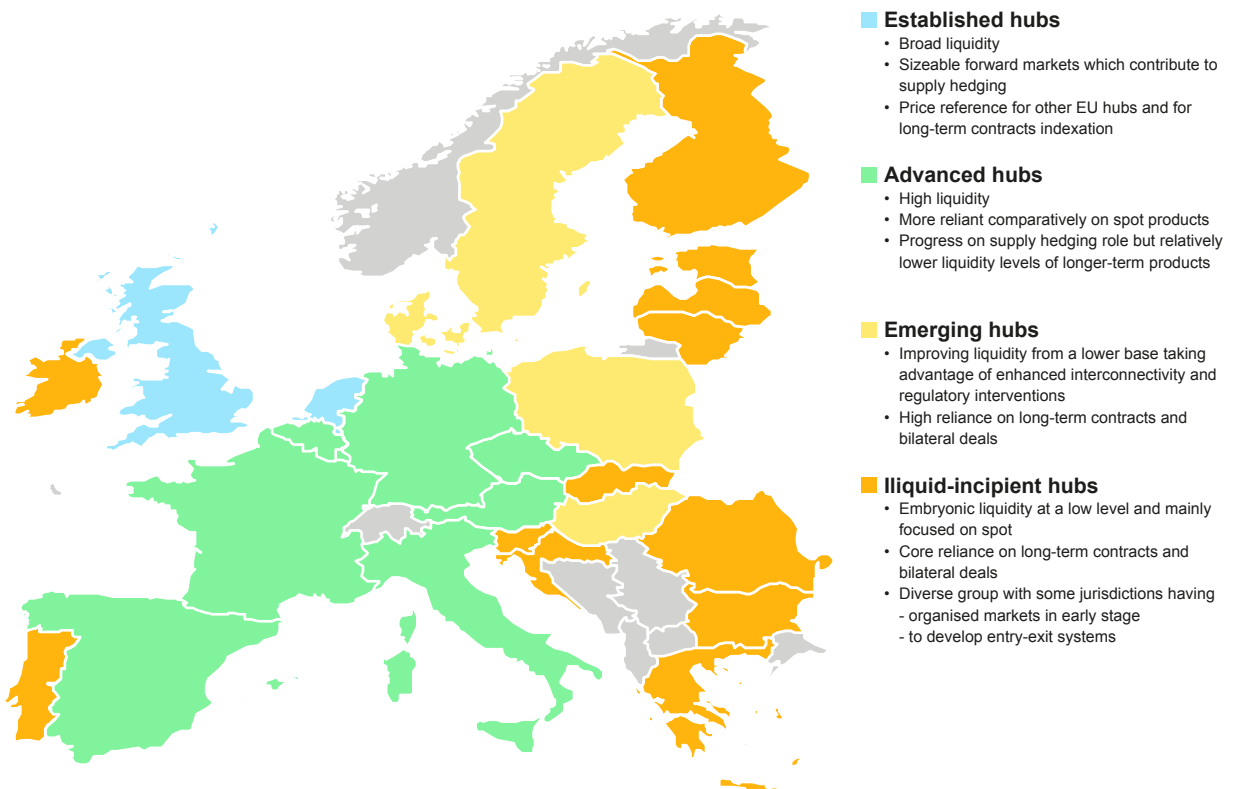


Source: ACER estimate based on REMIT data.

2.3 Gas hub categorisation

188 Figure 49 shows a ranking of EU gas hubs based on the results of the AGTM market participant’s needs metrics. The ranking remains unchanged in 2021 compared to the 2020 classification. While the analyses throughout Chapter 2 reveal some changes in liquidity at selected hubs, none of them were of a magnitude that would warrant a change in the functionality ranking. The main differentiating element in the ranking is the liquidity of forward products. TTF in the Netherlands and NBP in the UK continue as the only hubs in the established category in view of their larger forward liquidity, even if transactional activity at the two hubs continued to diverge in 2021. The new German THE hub has shown some improvements in selected metrics although it still remains categorised among the advanced hubs. As discussed in Section 2.2.1, among the group of illiquid hubs there were some positive developments, although the ranking remains.

Figure 49: Ranking of EU hubs based on monitoring results



Source: ACER estimate based on AGTM metric results

189 By way of example, the Lithuanian gas hub case study below discusses the broader market developments and the regulatory provisions that have backed the liquidity and progression in the recent years. The case study has been developed by the Lithuanian NRA NERC. To make the exercise further wide-ranging, a couple of external stakeholders have been interviewed to provide views about the hub growth drivers, and the challenges and hurdles ahead.

190 The findings of the case study are of particular interest to other markets in the region that are facing and seeking similar developments.

2.3.1 Case study: Lithuanian gas hub recent developments

Case study: Baltic-Finnish hub recent developments

Baltic States have made significant progress in diversifying their gas supply in the last few years. The organised gas exchange, GET Baltic¹⁰⁶, has been instrumental in these efforts since 2012, contributing to enhancing competition in the region. This case study discusses the market and regulatory drivers leading the GET Baltic hub progression.

Infrastructure development in the Baltic States

Figure i: Overview of supply infrastructure in the Baltic-Finnish region



Historically, the Baltic-Finnish region had fully relied on Russian gas supply (see point 1 below, in Figure i). However, the construction of the LNG terminal in Klaipėda in 2015 (see point 2 below) broke this monopoly, contributing to improving the security of supply in the region. In parallel, a number of gas infrastructure projects were implemented to facilitate gas flows to Lithuania and neighbouring countries.

Further market integration was achieved in 2020 by means of connecting the Finnish and Estonian gas systems via the Baltic connector pipeline (see point 3 below). That progress was further reinforced in May 2022 when the Lithuanian and Polish systems were connected via GIPL¹⁰⁷ (see point 4 below).

In parallel, the enhancement of the (bi-directional) Estonia-Latvia and Latvia-Lithuania interconnections has broadened the supply diversification options, making possible the transfer of LNG or NWE gas flows (via GIPL) to Estonia-Finland or to Latvia-Lithuania (see point 5 below).

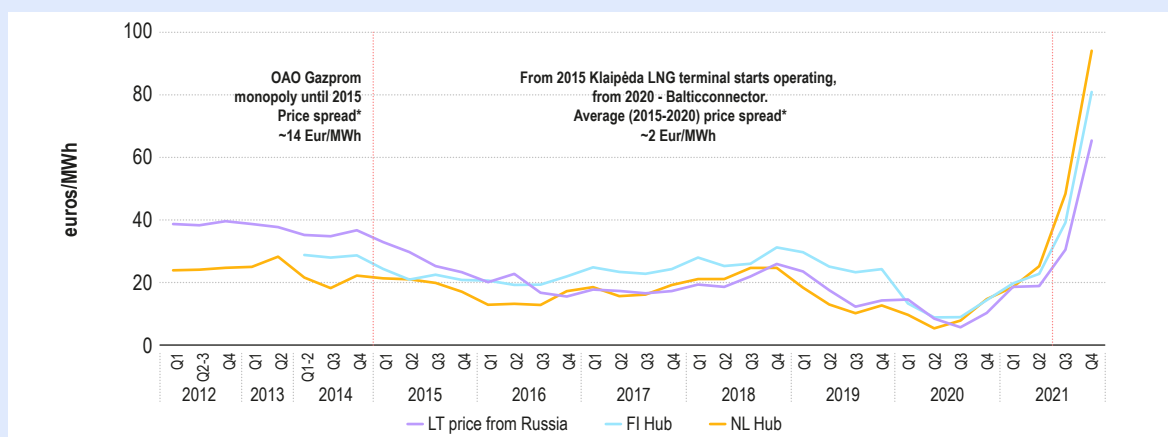
On the other hand, the underground storage facility in Inčukalns in Latvia is essential infrastructure today that provides security of supply and liquidity to the whole region. The withdrawal capacity of the storage site is being reinforced at present, and that shall improve the security of supply and efficiency of the whole system in the years to come.

The new pieces of infrastructure have enhanced the supply diversification options and hence promoted competition in the region. Consequently, a stronger price convergence with EU hubs, but also lower prices in the prevailing long-term contracts with Gazprom (via revising their indexations) have been achieved. Figure ii illustrates these developments.

106 GET Baltic is Lithuanian-based licensed natural gas exchange operator. It administers the electronic trading system for trading spot and forward natural gas products with physical delivery to Lithuania, Latvia, Estonia and Finland. GET Baltic plays a key role in forming the market price in the Baltic-Finnish region.

107 GIPL technical capacities 2 bcm/year from Poland to Lithuania and 1.9 bcm from Lithuania to Poland are offered at the GSA capacity booking platform.

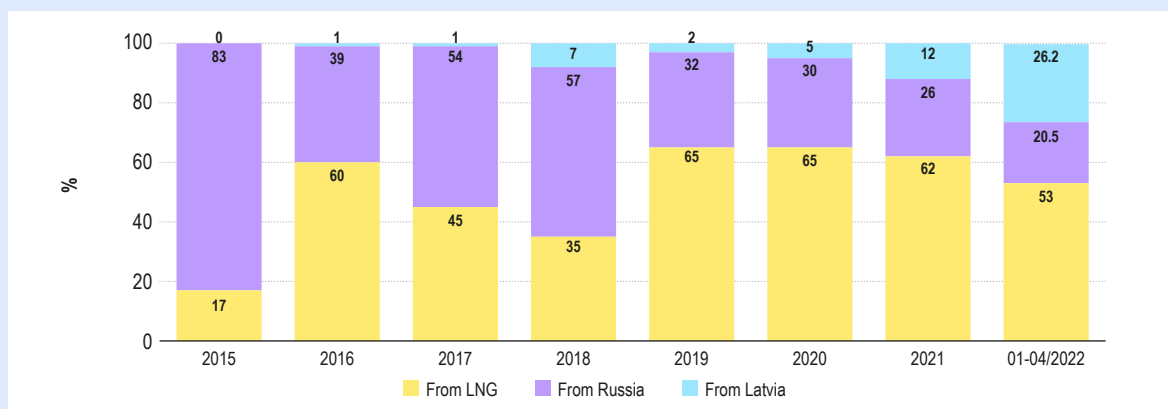
Figure ii: Evolution of Baltic region natural gas price changes – 2012 – 2021 – euros/MWh



*Price spread between the long-term supply contract signed with Gazprom and the Dutch TTF hub price.
Source: European Commission

Following the Russian invasion of Ukraine of 24 February 2022 Lithuania decided to halt Russian gas supplies in April 2022¹⁰⁸. That outcome has reinforced the significance of the Klaipėda LNG terminal to guarantee supply diversification in the region. The capacity of the terminal is fully booked until October 2023 (new capacity assignments will occur from 2023 onwards¹⁰⁹) and LNG volumes are at record highs, covering for a rising share of the total supply (see Figure iii). At the same time, Inčukalns UGS capacity has also been maximised¹¹⁰.

Figure iii: Natural gas import structure in Lithuania – 2015 – Q1 2022 – % share of total imports



Source: NERC

Drivers supporting GET Baltic liquidity

The Third Energy Package was implemented in Lithuania and Estonia in 2014, in Latvia in 2017 and in Finland in 2020. The Package provisions have been assisting the development of GET Baltic ever since. Moreover, a number of specific factors have (chronologically) contributed to the growth of the hub:

1. In 2017, the price discount that Gazprom had granted to the Lithuanian gas incumbent supplier since 2014 expired. The discount had restrained competition options for alternative suppliers.
2. In 2017, the liberalization of the Latvian gas market enabled GET Baltic to become a regional gas exchange. Trading services were expanded to cover Latvian and Estonian market areas (GET Baltic had operated in Lithuania since 2012). That milestone enabled Baltic gas suppliers to compete within the whole region.

108 See expanded considerations in [this communication](#) from the Lithuanian Energy Ministry.

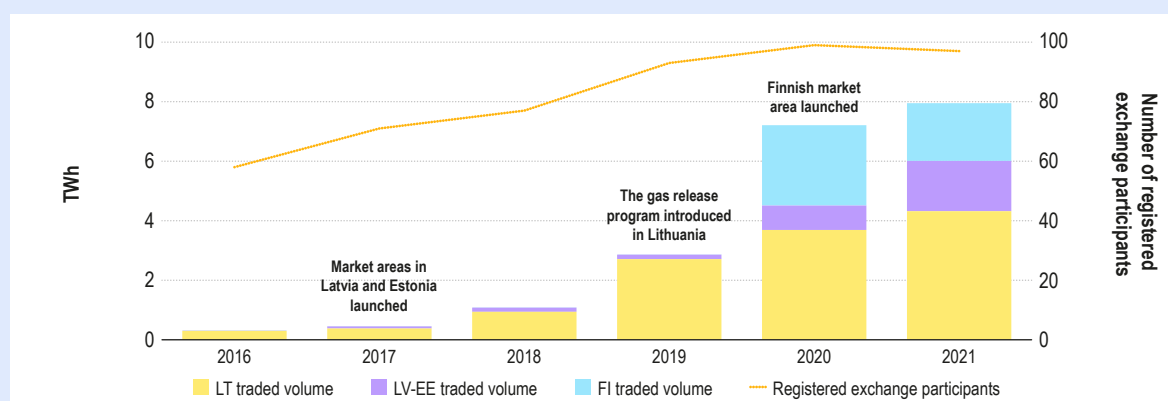
109 See [Public Consultation](#) on the matter.

110 Technical capacities are available in an [auction procedure](#).

3. In 2017, the Implicit Capacity Allocation (ICA) model was implemented. The model enabled to allocate cross-border capacities in response to price spreads (see section below). The ICA model has assisted the trading activity in the region, contributing to the increase of liquidity levels and price convergence.
4. In 2017, GET Baltic launched the Market Makers programme that ensured the liquidity and continuous trading at the exchange.
5. In 2017, GET Baltic introduced Baltic Gas Spot Index (BGSi) for the whole region and the separate market areas. The index became the main price indicator in the region and has been used to reference the prices of various bilateral supply contracts since.
6. In 2019, a gas release program was introduced in Lithuania. Regulated (district heating and electricity) energy producers were released from the obligation to buy gas from a designated supplier. In addition, the largest producer had to purchase half of their supply needs at the GET Baltic exchange.
7. In 2020, GET Baltic launched a new market area in Finland. Together with the ICA model and the zero transmission tariffs at Baltic connector (Finland and Estonia) have contributed to the increase in traded volumes at the exchange.

These events have contributed to the continuous growth in GET Baltic trading activity. Figure iii summarises these events and contrasts them with the YoY growth in traded volumes and number of market participants.

Figure iv: GET Baltic gas exchange activity evolution by traded volumes – 2016 – 2021 - TWh



Source: NERC based on GET Baltic.

The number of concluded transactions have grown from 1k in 2016 to 23k in 2021.

Implicit capacity allocation model

As mentioned, the ICA model was launched in 2017 between Lithuania, Latvia and Estonia, and later Finland in 2020. The model enables to allocate cross-border interconnection capacities and related gas volumes together. Following the ICA implementation, parts of the available interconnection capacities are allocated by the relevant TSOs at GET Baltic exchange; the trading orders submitted in one market area are displayed in real-time at the other areas. If matched, the underlying capacity rights to flow the traded gas volumes are directly allocated. The ICA model has assisted competition and liquidity at the Baltic region. It allows Baltic market participants to conclude transactions at the best price offered in the entire region, enhancing market integration.

After the inclusion of the Finnish market in 2020, the volumes traded via ICA have increased by a factor of four, contributing to reduced price differences between the Finnish market area and the Baltic countries. Throughout 2021, 1.6 TWh were traded in cross-border (ICA) transactions, which is 56% YoY rise.

Inter-TSO compensation mechanism under implementation and discount on LNG

Baltic market reforms have focused on reducing the region's reliance on Russian supply and on safeguarding its energy security via market integration with their neighbours. The EU Baltic Energy Market Interconnection Plan (BEMIP) has been instrumental in the strategy¹¹¹. As a milestone to these integration efforts, the gas TSOs of Latvia, Finland and Estonia signed a Memorandum of Understanding (MoU), setting out certain principles for an inter-TSO tariff compensation mechanism (ITC), which will undergo a detailed upgrade and review in 2022. The principles aimed at supporting the development of a single entry/exit gas market zone, encompassing the three Baltic States¹¹². The proposal established the same tariff at each entry point into the single zone, whilst it set zero tariffs at all cross-border points.

The ITC implementation is advancing under the guidance of a common roadmap, agreed to in April 2020 by energy ministries, regulators and transmission system operators from Estonia, Finland, Latvia and Lithuania (the latter is conducting a cost-benefit analysis to underpin the foundations of this ITC).

Trading activity and price overview with a focus on 2021

GET Baltic hub traded volumes reached an all-time high of 8 TWh in 2021 (+10% YoY). This is around 12% of the total regional wholesale Baltic-Finnish demand. However, the record-high gas prices and the extreme price volatility forced some market participants to limit their trading activity in Q4 2021 (even if the number of market participants remained stable). In this context, the Inčukalns UGS was filled below normal levels in 2021 due to the record-high prices, which also made the use of alternative fuels for heating more competitive. Furthermore, gas-fired power generation has become uncompetitive in the last months, limiting gas hub trading activity (power generators account for a relevant share of total gas-traded volumes). When high prices became apparent in Q4 2021 in NWE hubs; the EU gas hub references that served as index to the prices of bilateral supply contracts in the Baltic region led to enhanced correlation between the Baltic-Finnish prices and EU gas hubs. The record-high prices at EU hubs in contrast to the delayed BGSi price increase, but also the usage of Inčukalns underground gas storage, made GET-Baltic trade at a discount.

As [Figure v](#) shows, trading activity at GET Baltic is today centred on spot trading. One of the reasons for this is a relatively inconvenient payment system that does not offer effective clearing services and margin trading. That makes the trading of long-term products inconvenient and hence trading activity focuses on more affordable short-term products. Ongoing work by GET Baltic and NRAs is aimed at facilitating custom-made and clearing services. The new cost model is expected to make long-term trades more attractive and as such they could account for a much larger part of total traded volumes.

While GET Baltic day-products can be traded for up to 30 days, 90 percent of trades focus on day-ahead, within-day and previous-day trades¹¹³. In addition, in recent years, the Baltic market has seen an increased demand for the usage of BGSi index in bilateral and supply contracts. This trend will likely to encourage market participants to trade more actively at the GET Baltic exchange. The usage of BGSi in bilateral and supply contracts reduces the financial risk of purchasing and supplying gas with the same price index. More details on GET Baltic trading results can be found in GET Baltic monthly Trading Reports¹¹⁴.

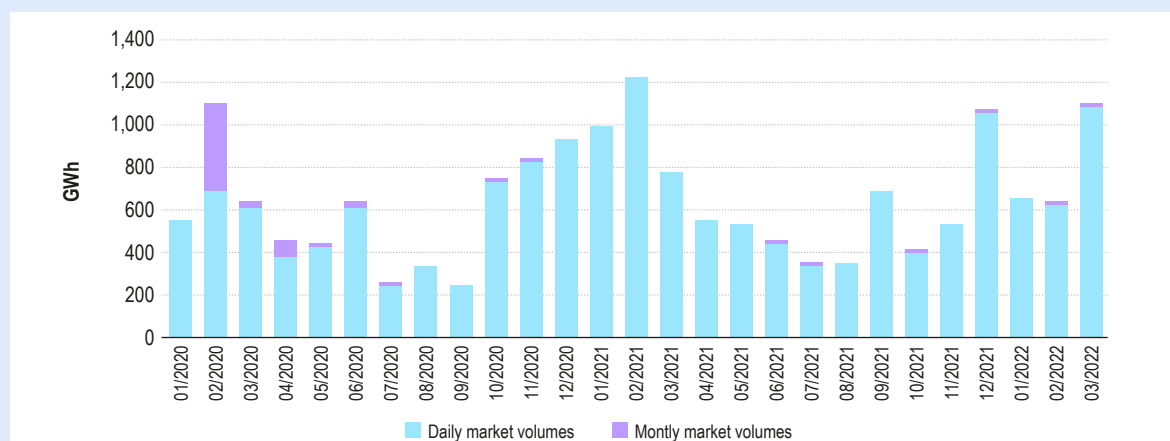
111 BEMIP infrastructure was one of the priority corridors identified by TEN-E regulation.

112 Lithuanian TSO did not sign the MoU, nor the ITC-agreement. Hence, Lithuania remains a fully separate entry/exit area. Once the ITC is revised based on the cost-benefit analysis, Lithuania may join.

113 The previous-day product was used chiefly as a balancing product available only in the Lithuanian market area. In March 2022, the trading of previous-day products was discontinued.

114 GET Baltic Trading Reports are published every month on [GET Baltic webpage](#).

Figure v: Monthly volumes traded at GET Baltic gas exchange per market (Daily/Monthly) – 2020 – March 2022 – MWh



Source: VERT based on GET Baltic.

Others – daily products from D-4 to D-30.

- 191 ACER has consulted the considerations expressed in the case study with relevant stakeholders active in the Baltic-Finnish gas market. They offered additional expert views about the drivers described in the case study and highlighted the challenges that could still hinder its further development.
- 192 The stakeholders recognise an enhanced role of the GET Baltic hub for sourcing and transiting regional supply, backed by the recent infrastructure expansion and the enumerated regulatory developments. However, the general perception is that the Baltic hub liquidity is very limited beyond the short-term horizon. The exchange is chiefly a spot physical trading venue, although stakeholders also recognise that it is more and more used as price reference to link the prices of selected supply contracts in the region. However, the opportunities to hedge forward prices and do financial trade are still very narrow.
- 193 One stakeholder underlines that the price differences among the three different trading areas (i.e., Lithuania, Estonia-Latvia and Finland) and the congestion at the cross-border IPs result in still rather separated markets. In its view, the implicit capacity allocation mechanism has had a limited impact yet in further uniting the markets. The same stakeholder also underscores that the Lithuanian market zone liquidity is the highest in view of the regulated provisions that compel the incumbent electricity and district heating producer to procure part of the gas volumes at the hub in conjunction with the role of the Klaipeda terminal.
- 194 Consulted stakeholders note that congestion has further increased since recently, after the decision to shift away from Russian supply. They are of the view that reducing the congestion between Lithuania and the Latvian-Estonian zones would particularly assist the development of the market. They also underline that the new Finnish-Estonian FSRU LNG terminal would contribute to alleviate congestions and back trading activity in the two related areas. Finally, stakeholders acknowledge that the regulatory efforts to formally merge the Baltic markets are delivering progress and that when they will further mature, the hub functionality will be further increased.

3. Impact of gas network codes on market functioning

195 This Chapter looks at the market effects brought by the implementation of the gas Network Codes and Commission Guidelines¹¹⁵. However, this year, the analysis does not include a comprehensive overview of the individual NCs' provisions and their impact¹¹⁶. The Chapter is structured across individual subsections, each dedicated to a key policy issue. Each subsection contains first the results of selected pieces of analyses and then adds some considerations to help contextualise the results of the analyses.

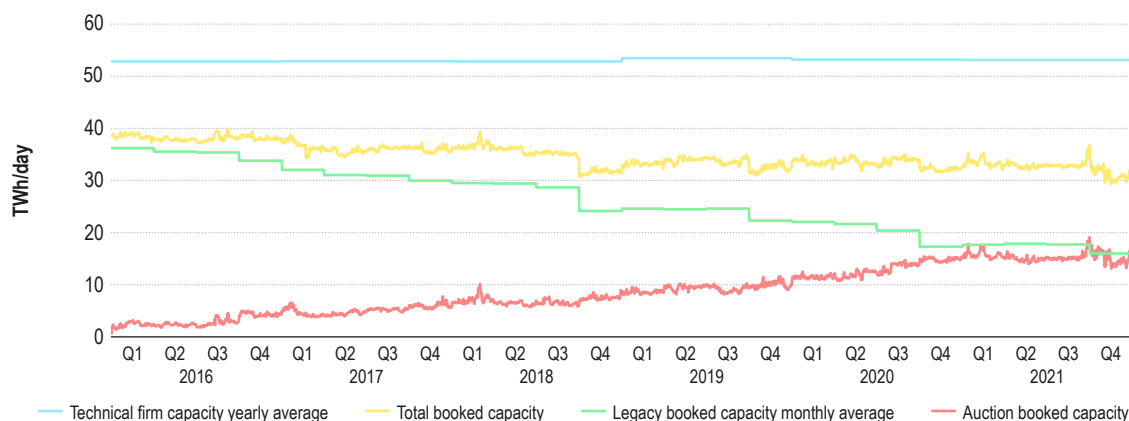
196 The Chapter contains four analytical sheets referring to two NCs: the Capacity Allocation Mechanism (CAM) and the Balancing (BAL) NCs.

Expiration and replacement of legacy transportation contracts

Subject: Evolution of the type of capacity products underlying the booked capacity at EU cross-border interconnection points (IPs).

Context: The assessment aims at measuring if the IPs' capacity underlined by so called 'legacy contracts' (i.e. those capacity contracts in place before the implementation of the CAM NC, most of them signed for a long duration) have been replaced by new bookings. The new contracts allow more profiling and follow the product structure and principles established by the CAM NC (i.e. products of various lengths that are allocated by competitive capacity auctions with the possibility to book both short and long-term capacity products).

Figure 50: Evolution of booked capacity at EU CAM interconnection points: total, legacy and CAM auction booked capacity – 2016 – 2021 – MWh/day



Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA data.

Note: The figure includes data for the CAM relevant IPs that have been in operation throughout the monitored period and excludes IPs that have ceased to be bookable points (e.g. Liaison Nord-Sud in France, Julianadorp the Netherlands, etc.). Interconnectors linking zones to LNG regasification facilities are out of scope of the CAM NC and are therefore not included in this assessment. Interconnectors with third countries are included only if the CAM NC applies to them, based on the decision of the relevant regulatory authorities.

115 The EU legislation comprises four gas network codes and one guideline. The Congestion management procedures guidelines (CMP GL) sets out rules for identifying and alleviating contractual congestion at interconnection points. The Capacity allocation mechanisms network code (CAM NC) sets out rules for allocation of transportation capacity rights at interconnection points. The Balancing network code (BAL NC) sets out the rules for gas balancing with a view to incentivise network users to manage their own daily gas flexibility by buying and selling gas. The Interoperability and Data Exchange network code (INT NC), which sets out rules for harmonisation of interconnection agreements between adjacent TSOs and data exchange procedures for key business processes. The Tariff network code (TAR NC) sets out the principles and rules for harmonised tariff structures for transmission networks.

116 In previous MMR editions the chapter dedicated to network codes has been structured in different sections. Each section offered selected considerations about the NCs' provisions, their implementation progression, the market context where the codes applied and the market outcomes resulting from the implementation of the codes.

Results:

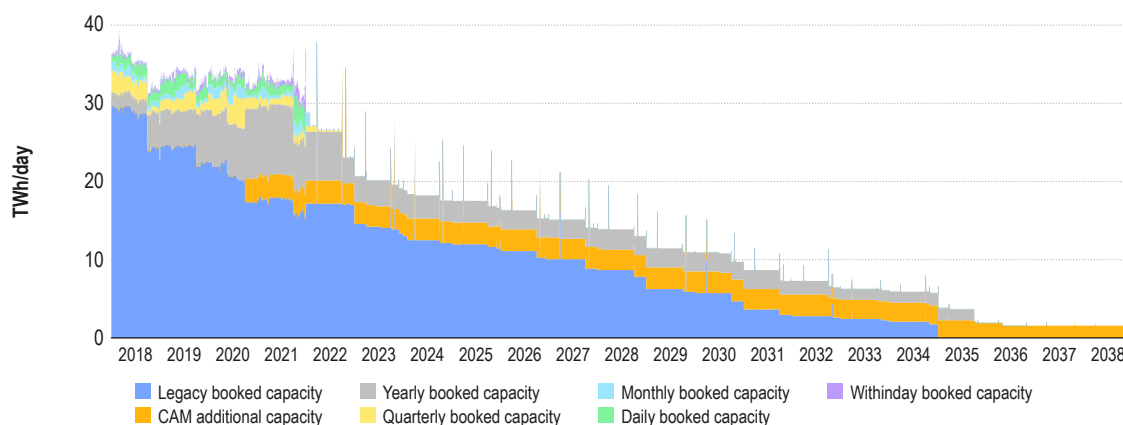
- At EU scale, the total booked capacities accounted for 60% of the total technical firm cross-border capacity at offer in 2021. This includes both legacy and CAM-based bookings.
- On EU average, capacity bookings made before the CAM NC implementation have halved since 2016. 85% of those expiring legacy bookings have been replaced with new CAM products (labelled as 'Auction booked capacity' in Figure 49). This is notwithstanding relevant differences in substitution ratios across national systems¹¹⁷.
- At the end of 2021, the IP bookings underlined by CAM products exceeded the capacity bookings underlined by legacy capacity commitments.
- While total booked capacities slightly decreased across 2021 in comparison to 2020, total bookings recovered in Q4 2021. The rise was backed by new bookings at a selected number of IPs that assisted new flow directions mainly to flow LNG across border into non-coastal markets and optimise flows given these new sources configurations.

Expiration and replacement of legacy transportation contracts in the coming years

Subject: Expiration calendar of legacy capacity contracts against the bookings committed until the end of 2021 with CAM auctioned products.

Context: The assessment aims at measuring the forthcoming degree of substitution of legacy contracts by CAM products. Figure 50 also presents the type of CAM products that are being contracted. CAM bookings are deemed facilitating more efficient and flexible bookings also available for the shorter timeframes. The assessment connects to the analyses and overview provided for the long-term supply contracts and their expiration calendar already discussed in Chapter 1, Figure 14.

Figure 51: Evolution of booked capacity and expiration of legacy capacity contracts at CAM relevant points – 2018 – 2038 – MWh/day



Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA data.

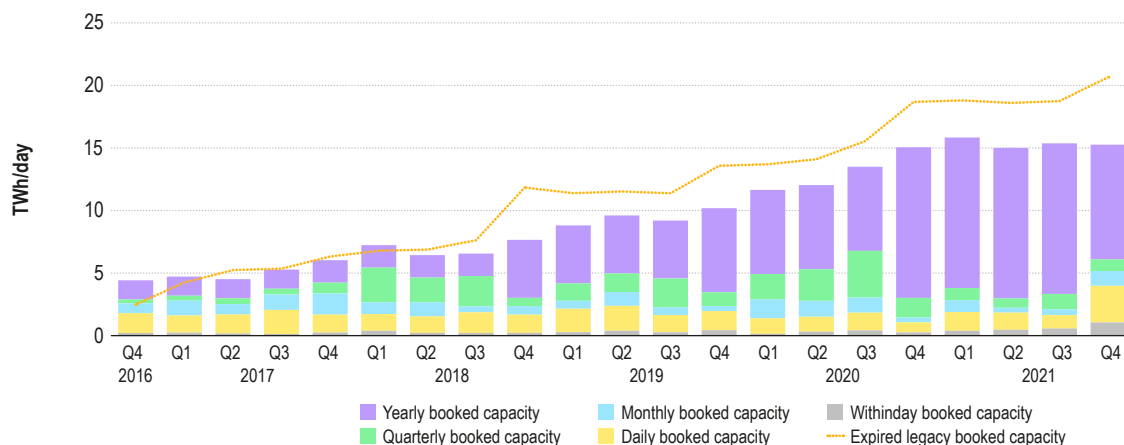
Results:

- At several IPs legacy capacity contracts will expire in the next couple of years. By 2035, all pre-CAM capacity contracts will have almost completely expired.
- The expectation is that the average bookings at EU IPs will gradually decrease. Their utilisation will be driven by the rising role of LNG supplies and the shift away from Russian supply and the increased injection of low-carbon gases, which are expected to be mostly produced domestically. The foreseen stagnation of demand will nuance the utilisation needs. (Other uses of the gas pipelines such as CO₂ and hydrogen will be subject to the chosen decarbonisation trajectories.)

117 Figure 33 in MMR 2020 offers a comparison of the changes in booked capacities across EU market areas.

- While legacy contracts have gradually decreased, CAM products of longer duration have gradually replaced them. Longer duration products, (i.e. quarterly and yearly products) attracted relatively less market interest in the first years of CAM NC implementation. However, as of 2019-2020, they became more prominent and the old legacy capacity contracts replaced by them. However the duration of these new contracts is of a shorter timeframe than the historical legacy contracts. There are some exception to that rule such as the long-term bookings committed by shippers and mainly Gazprom may cover longer timeframes, which could reach up to 15 years¹¹⁸. This is analysed in more detail in Figure 52 below.

Figure 52: Gas capacity booking trends – breakdown of CAM booked transportation capacity and expired legacy booked capacity – Q4 2016 – Q4 2021 – MWh/day yearly average



Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA.

Residual role of EU TSOs in balancing – volume of TSOs balancing actions

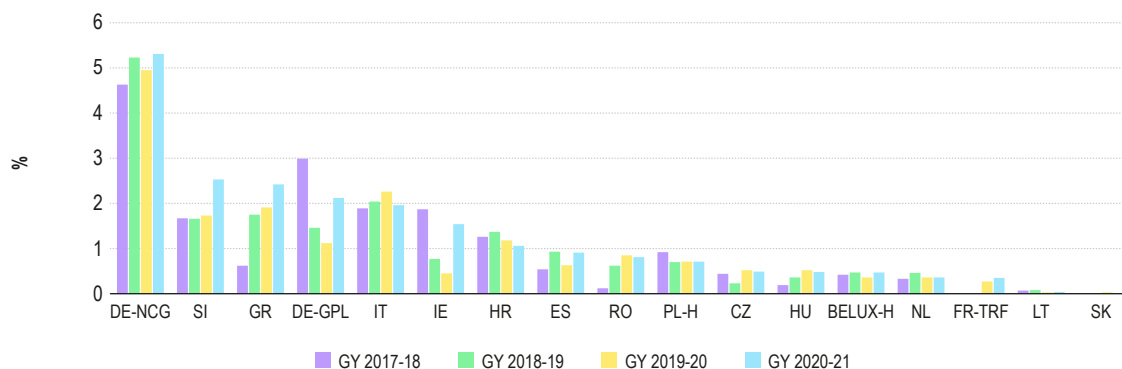
Subject: The residual role of TSO (or MAM¹¹⁹) in gas balancing: TSO (or MAM) transactions in the market area or balancing zone which they operate in a given gas year.

Context: The BAL NC creates the foundations of a market-based balancing regime by giving the main balancing responsibility to individual network users and requiring that TSOs/MAMs procure daily balancing products from the market. This changed role of the TSOs/MAMs enables the network users to trade imbalances on a non-discriminatory basis. The desired outcome of the code is to develop the short-term wholesale market and enhance gas-to-gas pricing by enabling network users to participate in these short-term markets and by incentivising them to do so. In this context, the TSOs were left with a residual balancing role.

118 The category CAM additional capacity includes specifically the long-term capacity allocated in 2017 via auctions in an ad-hoc open season for two interconnection points located along the onshore routes for further transport from Nord Stream II: Lubmin II and Deutschneudorf-EUGAL. This capacity was assigned before the incremental capacity amendments to the CAM Network Code entered into force

119 MAM means Market Area Manager.

Figure 53: TSO balancing volumes relative to gas entering the transmission system (per Gas Years) – 2017 – 2021 – % by volume



Source: ACER indicators based on ENTSOG data

Results:

- In most of the analysed balancing zones, the TSOs or MAMs balancing actions amount to 2% to 0.5% of gas entering the balancing zone on an annual basis.
- The German market area manager NCG stands out as their balancing actions represent a comparatively larger share of gas entering their market area, while the Lithuanian and Slovak TSOs stand out by the use of minimal volumes for balancing purposes.
- Other things being equal, higher (relative) volumes of TSO balancing actions indicate that market participants, who ought to be primarily responsible for keeping the system in balance, are having challenges. This may be because market participants do not have sufficient information on their own or system-level imbalances to know how to bring value to the system, or do not have access to a liquid spot market in which to trade their imbalances, or lack adequate incentives to balance by the combination of the listed factors. Very limited TSO volumes can be a typical challenge in smaller markets, where the TSO's role is key in bringing additional liquidity to the market. Limited TSO volumes might be connected as well to limited market participation and consequentially limited market liquidity. Having a dialogue between networks users and TSOs is key in evolving the balancing regimes' commercial design, a dialogue that ACER has consistently encouraged.
- Balancing zones have different levels of linepack flexibility – the extent to which the balancing zone can safely tolerate being physically imbalanced – which can substantially alter the frequency for a TSO to intervene for operational safety.

Network users' imbalances

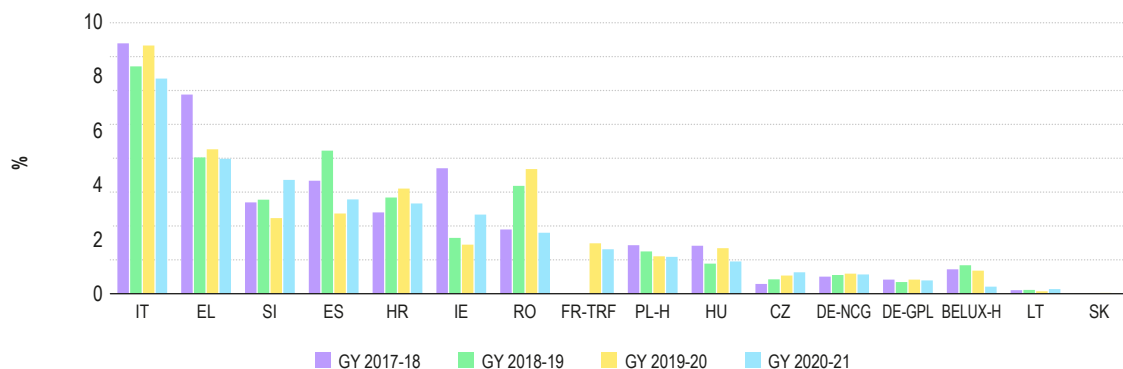
Subject: Aggregated cashed-out volume of network users imbalances in a given gas year. This indicator measures how network users are balancing their positions.

Context: Network users' imbalance shows the difference between network users' inputs and offtakes in/from a balancing zone. If a network user is short of gas at the end of the balancing period, they will be charged or cashed out by the TSO for the missing gas at a price higher than the market price. Similarly, if a network user is long at the end of the balancing period, they will be credited or cashed out by the TSO for the excess gas at a price lower than the market price. Such a system is meant to encourage network users to proactively manage their imbalances by buying or selling gas on the spot market during the Gas Day¹²⁰.

Network users' imbalances are closely related to their ability to forecast demand and their ability to respond to unforeseen demand changes. Liquid markets also play a role in allowing network users to change their position. Furthermore, how the non-daily metered offtake is handled in a balancing zone, in other words how non-daily metered users play a role in a daily market has an impact on this indicator.

¹²⁰ Gas Day has a harmonised start and end from 5.00 to 5.00 UTC the following day for winter time, and from 4.00 to 4.00 UTC the following day when daylight saving is applied.

Figure 54: Total imbalance quantities relative to gas entering the transmission system per Gas Year – % by volume



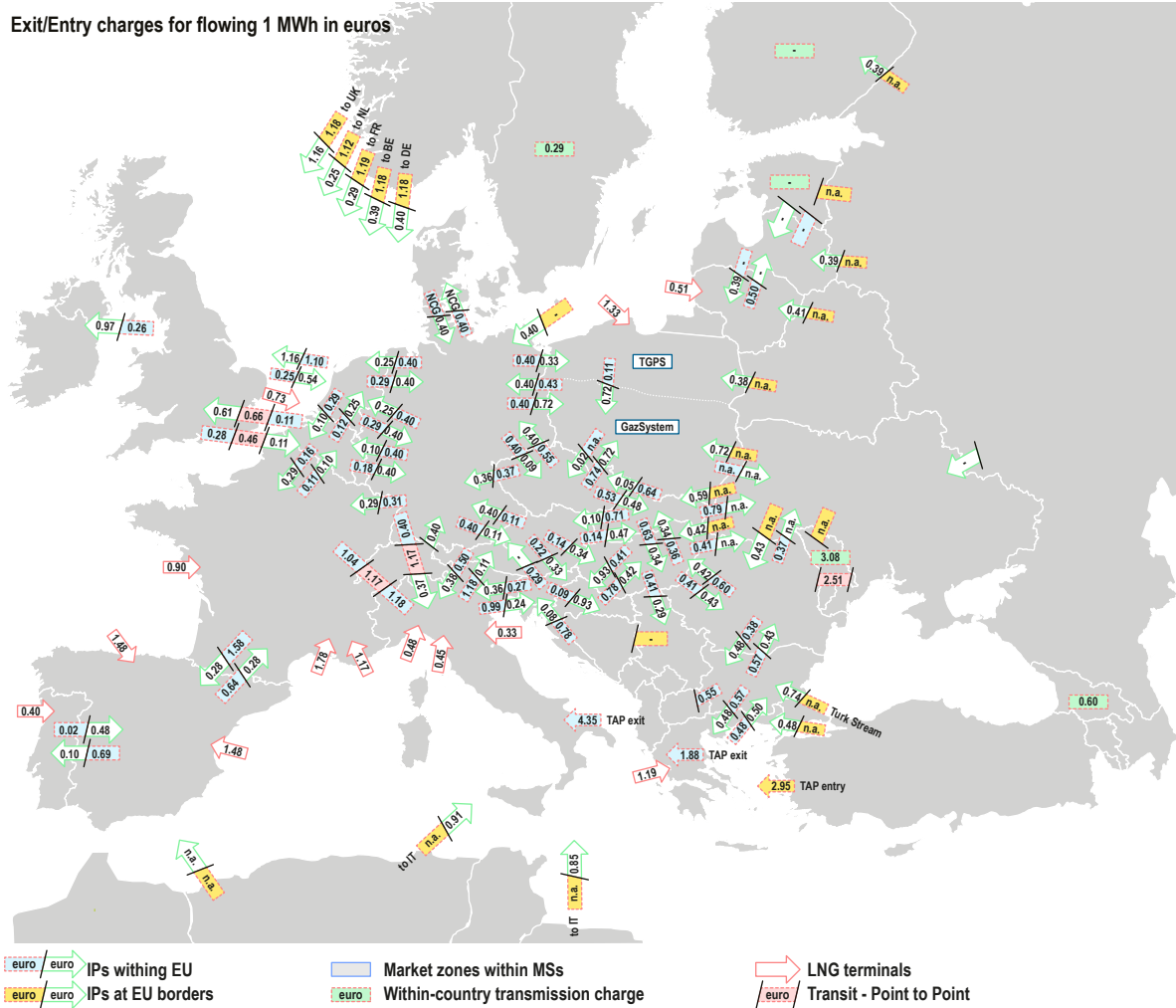
Source: ACER indicators based on ENTSOG data

Results:

- There are considerable differences in the aggregated volume of network users’ imbalances amongst the analysed group of balancing zones. Market areas ranging from close to 8% of all gas volumes entering the balancing zone in Italy to below 1% in the Slovak, Lithuanian, German, Czech and the Belux (high-calorific) gas balancing zones.
- The variation in total network user imbalances is not only the result of differences in balancing performance of network users in different zones but of differences amongst balancing regimes. Crucial differences that influence network user imbalances include, amongst others, obligations for network users to either balance their input against a projection of offtake or against actual offtake; an obligation for network users to balance their inputs and offtakes either over a gas day or in shorter time intervals; and the possibility for network users to access the system’s linepack flexibility to avoid being cashed out when out of balance.
- Network users’ imbalances are also closely related to their ability to forecast demand and their ability to respond to unforeseen demand changes.

Annex 1: Back-up figures

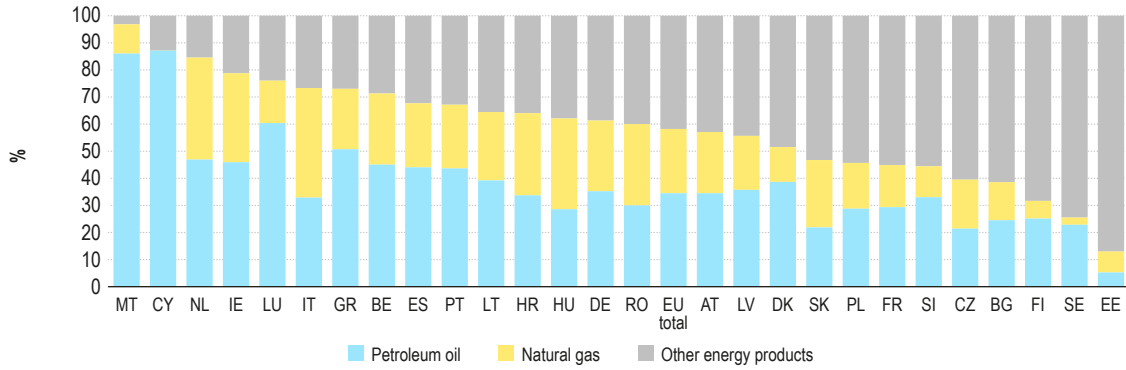
Figure i: Comparison of average gas cross-border transportation tariffs and LNG system access costs – April 2022 – euros/MWh



Source: ACER calculation based on ENTSO, CEER and individual TSOs (2022).

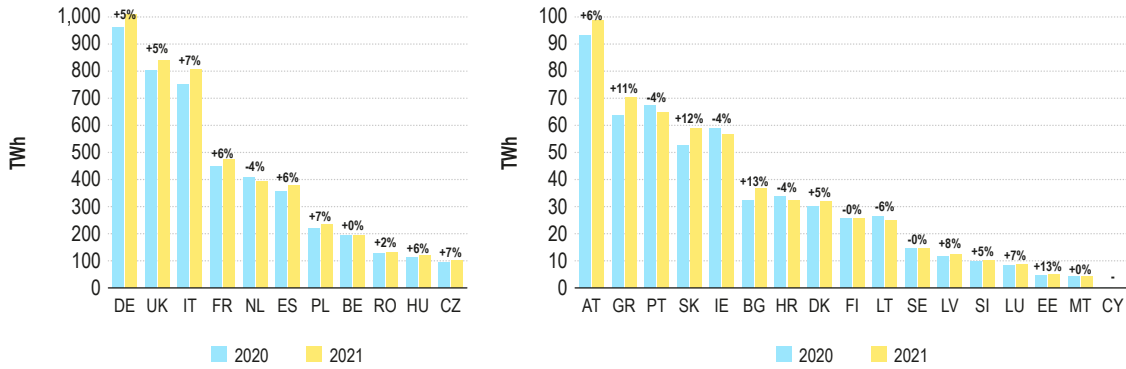
Note: For cross-border IPs, the map displays 2022 exit/entry charges in euros/MWh for the yearly product. See MMR 2016 annex 1 for further clarifications. For LNG terminals the tariff refers to 2022. The figure considers the costs derived from the bundled service (unloading + storage + regasification) of a 1,000 GWh LNG cargo, which regasifies the whole amount in a period of 15 days, plus the entry tariffs from the LNG terminal into the transportation network. Besides physical flow between the Yamal Pipeline (TGPS) and the Polish VTP (Gaz-System) a backhaul reverse flow is possible.

Figure ii: Share of natural gas and oil in MS's primary energy consumption – 2020 - %



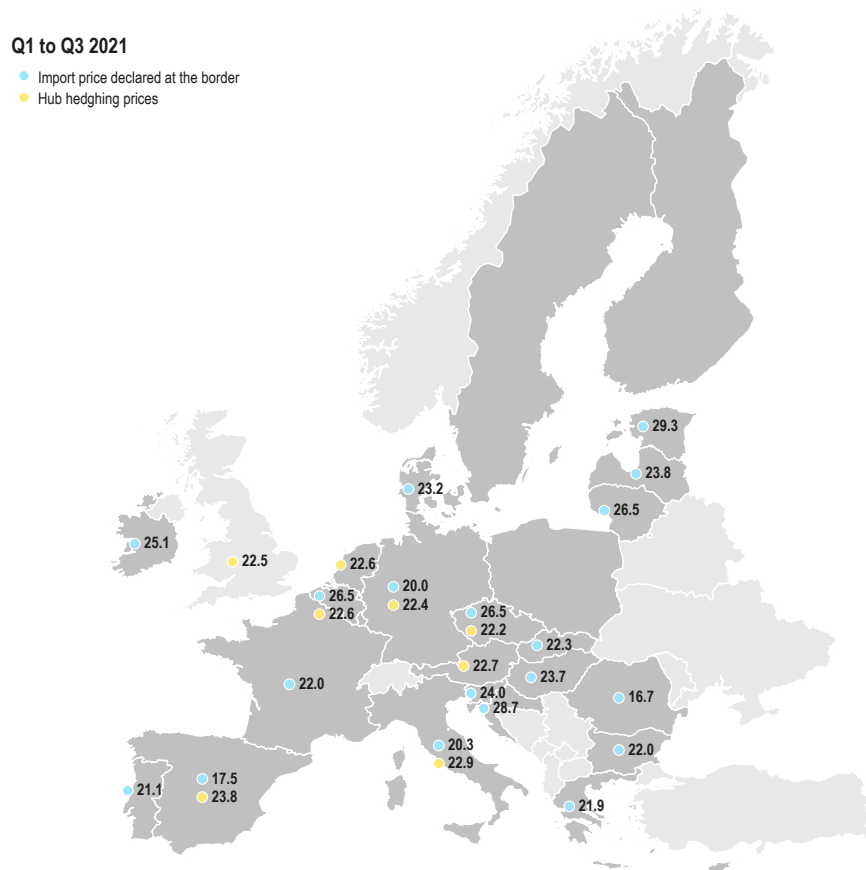
Source: Eurostat

Figure iii: Natural gas consumption per EU MS – 2020 – 2021 – TWh/year and YoY change in %



Source: Eurostat

Figure iv: Estimated average suppliers' gas sourcing costs at selected MS – Q1 – Q3 2021 – euros/MWh.



Source: ACER calculation based on Eurostat Comext, ICIS and NRAs.

Note: Import prices for Austria, Netherlands, France, Finland, Romania and Poland could not be assessed.

Figure v: Overview of gas flow changes across interconnection points and LNG terminals – First half of 2021 vs first half of 2022 - % of variation



Source: ACER calculation based on ENTSOG and Refinitiv (2022).