Global Gas Report 2023

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Foreword

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We are pleased to present the 2023 edition of the **Global Gas Report**, which offers a significant perspective on the evolution of the global gas markets amidst a historical global energy crisis. This crisis has been unfolding in parallel with the energy transition towards a more sustainable future, as the world has struggled to align with the decarbonisation goals outlined in the Paris Agreement. Global emissions grew in 2022 with coal related emissions reaching an all-time high, due to gas to coal switching amidst the gas price and supply crunch.

In 2022, the global gas markets experienced shifts demonstrating remarkable flexibility and exceptional resilience, in the face of unprecedented shocks from supply and demand sides. These shocks included the conflict between Russia and Ukraine, which exacerbated to the extreme the already tight global supply situation and drove gas prices to the highest ever recorded, as the supply of Russian pipeline gas to Europe dropped, causing a pressing search for additional imports to the continent. The unaffordable prices were detrimental to many developing countries, especially in South Asia, who suffered painful energy supply shortages and prolonged blackouts.

Nevertheless, by September 2023, European storage levels exceeded required capacity, thanks to expanded import infrastructure, massive additional LNG inflows, and increased production of domestic natural gas. While Europe's commendable rapid development of new infrastructure and efficient utilisation of existing gas networks has been critical in rebalancing the regional situation, we should not forget that it does not eliminate the lingering supply risk, as global gas supply remains just as constrained.

Undoubtedly, we saw greater focus on energy security by governments, energy companies, and financial institutions, with investments in infrastructure for source diversification and alternative energy sources. This helped to establish a new equilibrium in the gas market, although it remains unstable and seems already challenged by the new conflict in the Middle East between Israel and Hamas.

We are also continuing to witness a high level of uncertainty in energy supply planning for 2030 and beyond. The substantial discrepancies in major energy and gas demand and supply outlook scenarios have introduced a significant level of risk into the gas markets going forward, raising questions about the necessary investments to achieve a more stable equilibrium. We delve into this issue in-depth in the report, exploring the ranges of variability across different scenario assumptions and their implications for supply security in the future.

Foreword

We emphasize that the prolonged period of low investment in the development of natural gas resources over the past decade has been a major factor contributing to the current supply shortage. To achieve balance in the market and to ensure affordability, sustainability, and security of supply, new investments in natural gas are required, alongside investments in low carbon gaseous energy, including renewable natural gas, hydrogen and carbon capture and storage.

As we think about how much gas we will need in the coming decades, we mustn't forget about the emerging regions of the world where population and energy needs are quickly growing. The huge economic engines of the most populous countries in the world, China, and India, still rely heavily on coal, and the gas crisis contributed to an upward trajectory of its use. Africa is the fastest growing region of the world with the youngest population, 600 million of which lacks access to power while many others are faced with unstable energy systems and weak infrastructure that require reinforcement for any energy transition to happen.

Importantly, while natural gas will continue to play a pivotal role in the energy transition facilitating the decarbonisation of the global economy, the gas sector itself will also undergo a process of decarbonisation. This is imperative, and we call for an acceleration in the deployment of carbon capture, low-carbon, and renewable gases. We also stress that doubling down on the elimination of methane emissions is required to make this transition possible. Realising these ambitions will require collaboration within the gas industry and, importantly, the implementation of appropriate policy tools and frameworks, including emission pricing, the removal of barriers to deployment, and access to finance.

To this end, this year's report explores future pathways for natural gas, low-carbon, and renewable gases to drive the energy transition, in conjunction with the increasing share of renewable energy and storage technologies. Amongst the pathways, we underscore the critical importance of energy conservation and efficiency to minimise demand, with numerous readily available opportunities to pragmatically reduce gas consumption without hurting the economy.

Finally, as we have seen in a clear case example last year when it saved Europe, LNG is a critical energy source that is flexible, abundant, and efficient. The report includes a highlight section on the role of LNG in delivering essential energy transition flexibility now and in the future, as it will become increasingly necessary in a decarbonised world, while also progressing to decarbonising the fuel. So, we emphasize that only gas investments capable of demonstrating their future-proofing and excellence in reducing methane emissions are likely to succeed.

Today more than ever, the world requires comprehensive energy planning to achieve a better balance between security, sustainability, and affordability, because when security and affordability are compromised, sustainability fades out of focus. Hence, balancing this trilemma is essential for the global energy transition to take place and to achieve the deep emissions reduction necessary in the fight against climate change.

We invite you to delve into this report and explore the future pathways for the gas industry, learning how gas will continue to provide the assurance of sustainable, secure, and affordable energy for the world.

Contents

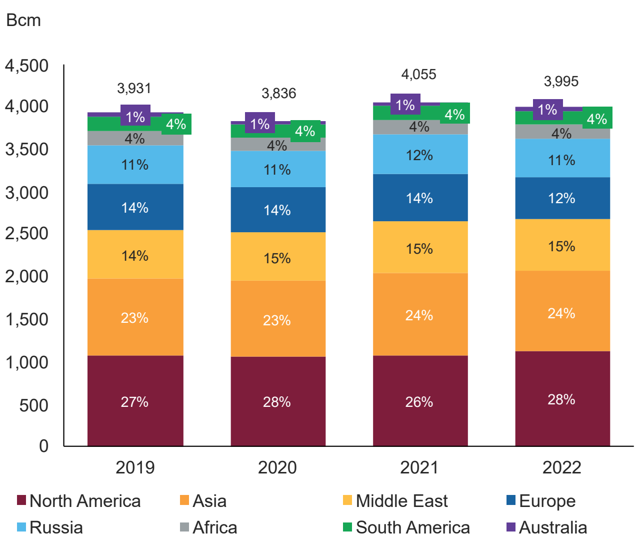
Executive Summary

2022 became the most turbulent year in the history of the gas industry, marked by unprecedented supply and price shocks. In 2023, as supply remains tight and demand outlook uncertain, the market entered an "unstable" equilibrium, remaining highly sensitive to any movements on either supply or demand side.

The energy trilemma has come into sharp focus when the world was reminded that energy security and affordability are necessary to stay on the course of the energy transition. Prior to the crisis, the policy focus was positively on sustainability; however, it was also deprioritising security and affordability, as those two seemed to be assured at the time, until they returned to become the priority in 2022. As evidenced by growing coal use and emissions, sustainability cannot be fully realised without the pillars of security and affordability, and therefore all three need to be in balance. Natural gas, low carbon, and renewable gases are crucial contributors in this sense, as they enable development and industrialisation in developing regions, enhance sustainability by addressing air quality problems from coal use, make the grids more resilient to support massive scale-up of renewables, and foster competitive industry decarbonisation. For regions looking to transition to renewables in the short term, gas and its infrastructure serve as key flexible and dispatchable sources tackling long-term intermittency, enhancing the reliability of grids.

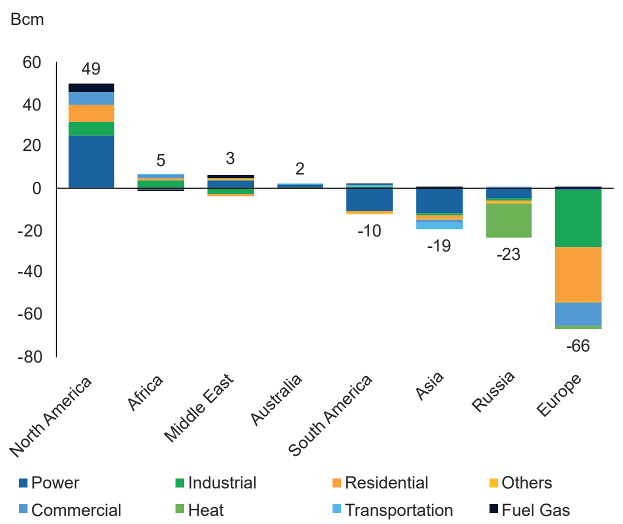
Global gas demand decreased by 1.5% in 2022 compared to 2021, with large declines in Europe and Asia offset by strong growth in North America. Falling demand in the regions hit hardest by the energy crisis persisted during H1 2023 and was primarily driven by industrial slowdown and decreased heating demand caused by a mild winter in the northern hemisphere. Although global demand dropped by 1.5% in 2022, regional demand destruction was a lot more pronounced. Europe's gas demand decreased by almost 12% in 2022 year-on-year, in response to the supply and price shocks coming on the heels of the Russia-Ukraine war. The good luck of a very mild 2022-23 winter was a major contributor to Europe's reduced gas demand, together with significant losses in industrial demand, gas to coal switch, and renewables uptake. Spikes in international spot LNG prices caused the demand in Asia to fall by 18 Bcm (1.9%) in 2022 compared to 2021. Significant demand destruction also happened in South Asia, where the price of LNG became unaffordable, causing switching to coal wherever possible and leading to shortages and blackouts. For instance, Pakistan and Bangladesh saw a 12% and 15% reduction in gas demand, respectively. On the contrary, North American gas demand grew by 4.8% or 49 Bcm year-on-year in 2022, a notable increase driven primarily by increased gas-fired power

Figure 1: Global gas demand, split by region



Source: Rystad Energy

Figure 2: Global gas demand sector year-on-year change, split by region (2021 – 2022)



Source: Rystad Energy

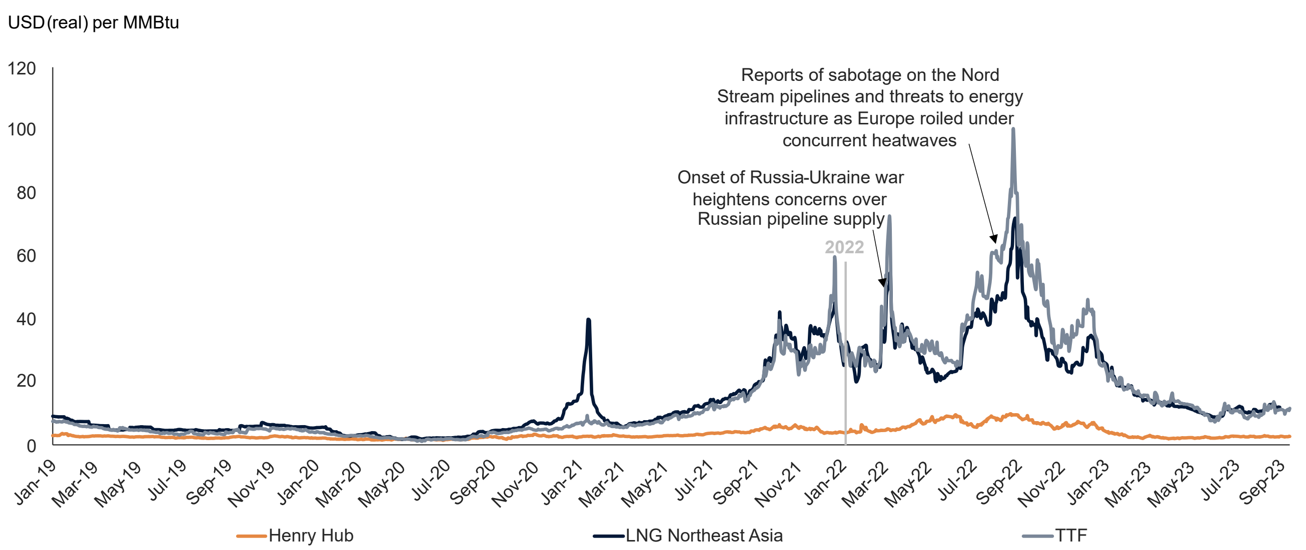
generation as well as residential and commercial applications. The North American market prices remained largely isolated and affordable, due to its predominantly regional nature with domestic production. Looking at 2023, from January to August, the European Union (EU) saw a cumulative gas consumption decrease of roughly 10% year-on-year (both an effect from industrial slowdown and the EU's intentional switch from gas to other energy sources), while China saw gas demand grow by 5.4% year-on-year during H1 2023.

Global gas production in 2022 stayed flat in comparison to 2021 with a marginal 8.3 Bcm uptick, which is less than a 0.5% increase year-on-year. The first half of 2023 saw a mild revival in global gas supply, yet the final annual result remains uncertain. Looking back at 2022, curtailment of Gazprom's output in Russia was offset by supply growth in North America, which grew from 1,160 Bcm to 1,213 Bcm, and in the Middle East, which grew from 670 Bcm in 2021 to 687 Bcm in 2022. In Europe, incremental production in 2022 largely came from Norway, which has been maximising output (7% growth year-on-year) to increase exports to the rest of the continent. In Asia, gas production rose modestly from 696 Bcm in 2021 to 712 Bcm in 2022, driven mainly by higher production in China and Central Asia. By contrast, Africa experienced falling gas production of 1% (2.9 Bcm) between 2021 and 2022.

2022 witnessed unparalleled turmoil in gas prices. Since late 2021 gas prices had been elevated and volatile, and trade balances tight. The commencement of the war in Ukraine in 2022 created a perfect storm causing gas prices to rise to the highest record ever, as the world struggled to allocate the scarce gas supply. Gas prices experienced multiple record spikes after the onset of the war and triggered a cascade of geopolitical and energy sector responses. The situation was further impaired with the explosion of the Nord Stream pipeline in September 2022. The peak gas price was seen in late August 2022, when prices reached an all-time high as the Netherlands-based Title Transfer Facility (TTF) closed at around 90 USD/MMBtu and Asian spot LNG prices surged past 60 USD/MMBtu. Asian prices consistently traded below the TTF, thanks to a combination of factors that includes fluctuating demand due to Covid-19-related lockdowns in China, price-induced demand contraction in the south, southeast regions, and fuel-switching.

Gas prices have cooled in 2023, largely due to demand-side adjustments in Europe and Asia, yet they remain above pre-covid and pre-energy crisis levels. The shortage of global supply, which was the key reason behind last year's shocks, is still there: the market is in a state of a fragile and unstable equilibrium. This cooling has been driven by demand contraction, marginal supply growth and infrastructure debottlenecking. Nonetheless, Europe's growing dependence on LNG has rendered global gas prices increasingly vulnerable to global LNG supply risk, as shown during recent price movements due to the strikes in Australia. At the time of writing, the new development, and the

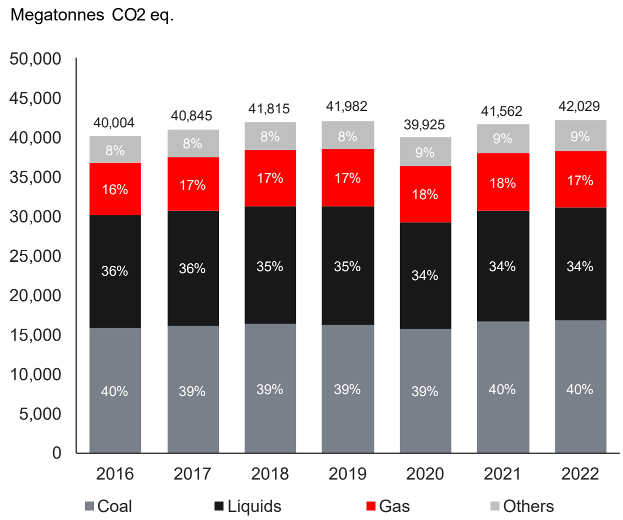
Figure 3: International gas prices



Source: Rystad Energy; Argus (LNG Northeast Asia) ongoing escalation of the conflict in the Middle East is sparking further price volatility and tension in the market, highlighting once again how in a general context of tight markets, gas hub prices are highly sensitive to geopolitical turmoil and supply dynamics.

LNG has been crucial in navigating through the gas market crisis, playing a key role in offsetting the shortage in Europe, with trade growing by 4%. Over H1 2023, global LNG exports saw a 4.1% year-on-year increase, despite volatilities due to facility maintenance and outages during the Northern hemisphere summer months. In the context of the globally tight LNG supply, while it was instrumental in keeping the lights on in Europe, the unaffordable prices left some countries in Asia in the dark. In 2022, Europe's natural gas imports shifted from Russian pipelines towards LNG leading to a 69% increase in its LNG imports, reaching 124 million tonnes (169 Bcm) and making Europe the biggest importing market, absorbing a significant share of the global LNG volume by outbidding other customers. Roughly two thirds of the additional volumes (~30 million tonnes) came from the United States. In Asia, China reduced LNG imports from Australia and the United States by a total of 21 million tonnes, while it increased imports from Qatar by approximately 7.4 million tonnes. In September 2023, there was disruption in gas supply from Australia due to rolling strikes, work bans and stoppages at the Gorgon and Wheatstone LNG facilities, potentially affecting around 5% of global LNG production, impacting volatility and level of international gas price indexes.

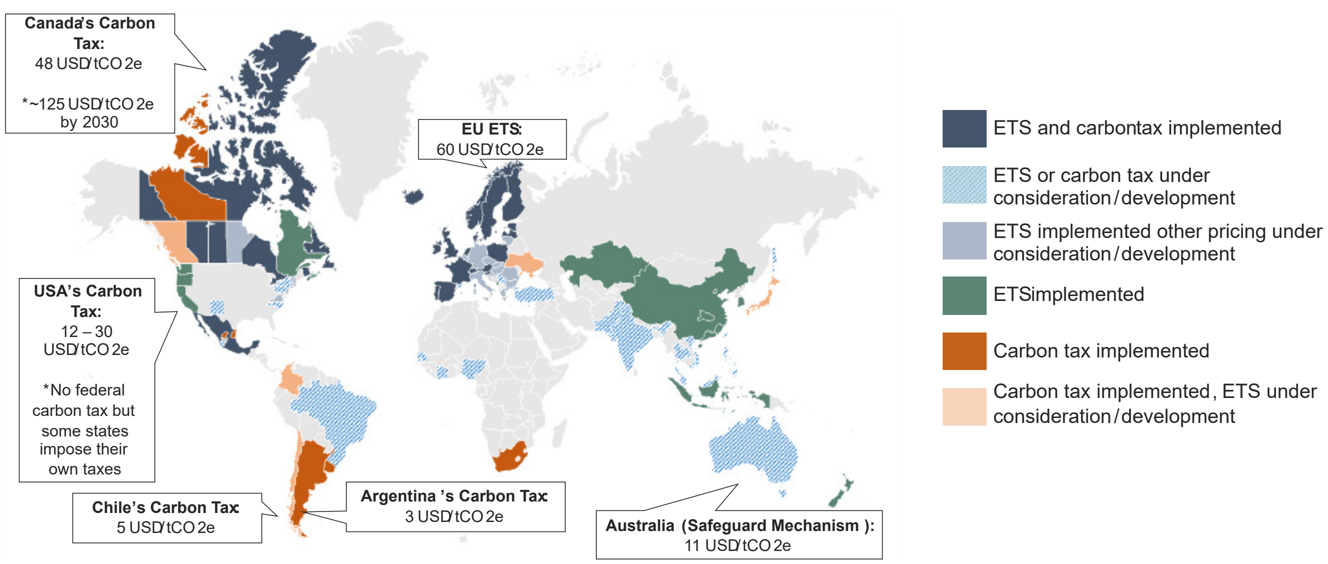
Figure 4: Global energy emissions, split by energy source



Source: Rystad Energy

Total global energy CO2 emissions in 2022 continued an upward trajectory with a 1.1% yearly growth, reaching another record. Emissions from combustion of natural gas saw a minor decline in 2022, totalling about 7.2 giga-tonnes CO2-e, partly attributed to price spikes which incentivised gas-to-coal and gas-to-oil switching. An all-time high in emissions from coal was reached at about 16.8 giga-tonnes of CO2-e, despite worldwide initiatives to diminish dependency. 2022 and 2023 continued the decade-long trend with coal having a 40% share of global power sector emissions, while

Figure 5: Global carbon pricing map



Source: Rystad Energy; World Bank

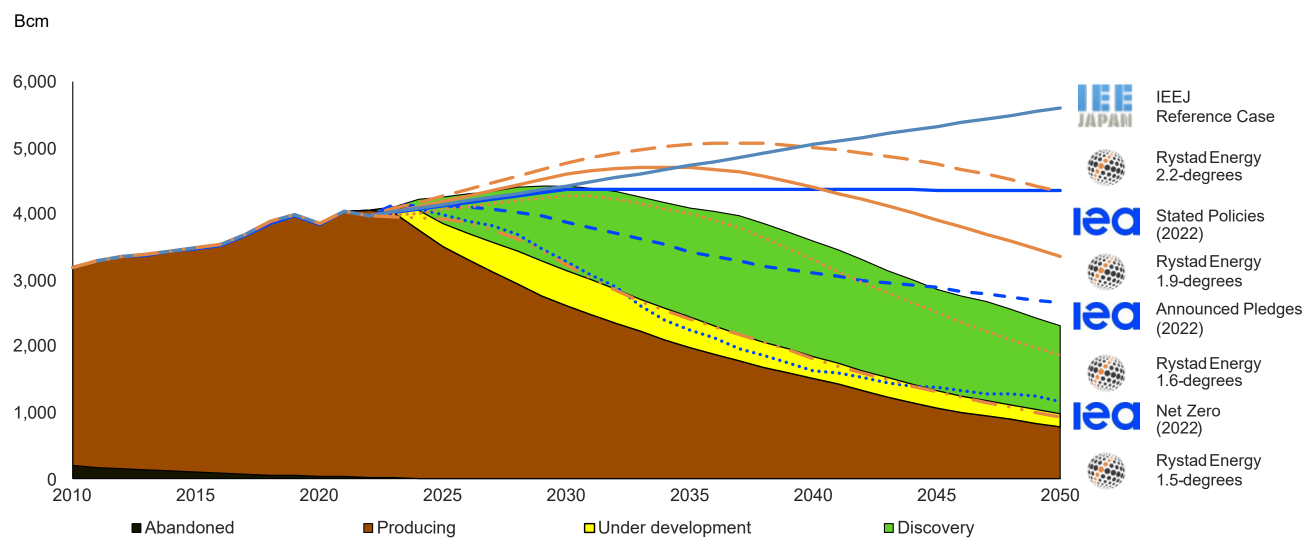
the global economic engines and major energy consumers like China and India increased their coal usage and approved new coal plants to mitigate energy security risks. Coal usage growth shows the importance of stability in global gas markets in minimising emissions. In H1 2023, lower gas prices, nuclear recovery, and power production from renewable energy sources have reduced coal consumption and emissions, especially in Europe.

Analysis of future potential trajectories of global gas demand from a wide range of existing energy transition outlooks towards 2030 and beyond reveals unprecedented uncertainty and illustrates that continued investments in the natural gas value chain are needed to cope with natural supply decline, global demand dynamics, and likely growth in several regions. Gas demand scenarios have important implications for policy decisions, as the supply will need to be developed ahead of demand. For this reason, comprehensive and balanced energy planning is needed to avoid further supply crises. Otherwise, the required natural gas supply may not be developed to meet demand resulting in heightened emission levels and increasing frequencies of blackouts. Restoring a sustainable balance in the global gas market is imperative and requires addressing the existing supply shortfall, an outcome of a prolonged under-investment period. Investment levels in gas supply development have been reduced by 58% in the period between 2014 and 2020, and only started to marginally recover in 2021. Without additional injections, the current total existing and approved gas production level is expected to reach about 4,100 Bcm in 2023. These output volumes are projected to decline to about 3,100 Bcm in 2030 due to asset maturation and natural decline. The projection indicates a further decline to 1,850 Bcm in 2040, followed by a decrease to just under 1,000 Bcm in 2050.

Amidst the energy transition targets and shifting supply dynamics, decarbonisation policies have been disproportionately focused on the supply side, while energy conservation and demand-response have been overlooked as powerful tools for emissions reduction through reducing overall energy usage. Proactive demand management planning will promote a more efficient use of energy and simultaneously reduce tightness of the global gas market by reducing gas demand in an economically and industrially sustainable way, while efforts to bolster supply through optimisation must occur in parallel. These actions can improve resource availability, shore up energy security, and stabilise the energy landscape. Measures fall into "preventive" and "reactive" categories, respectively managing consumption proactively and responding swiftly to periods of resource constraints or grid stress.

The acceleration of low carbon gaseous energy is an essential building block of the energy transition. Abated natural gas with CCUS, green and blue hydrogen (including derivatives like clean ammonia), biomethane and e-methane, will play an increasingly significant role in an achievable and just transition, offering a viable decarbonisation option in

Figure 6: Global gas demand scenarios from various institutions versus operational, approved and discovered assets (2010 – 2050)[1]

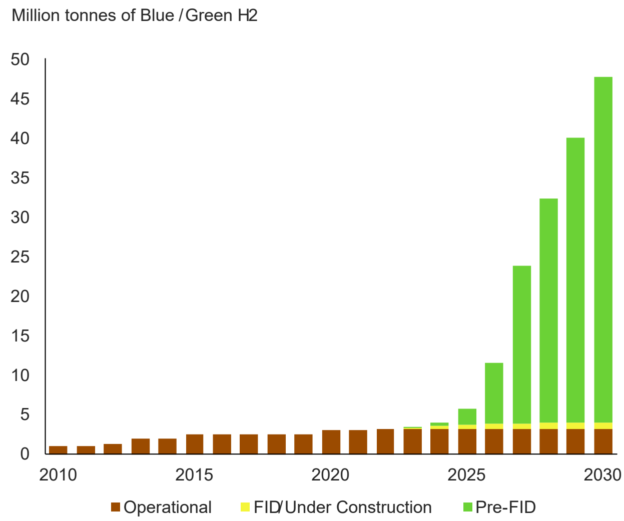


Source: IEA; IEE Japan; Rystad Energy

[1] All historical and forecasted values are scaled to be identical in 2022 to account for different heating and caloric assumptions.

many applications such as power generation, reactant/feedstock need, heating, and heavy transport, provided they are accessible in sufficient quantities and are cost-effective. During the transition, blending can be performed between methane and low carbon and renewable gases, to reduce emissions. Although there is momentum in low carbon and renewable gas supply growth, reinforced significantly by the energy crisis and ambitious new energy transition policies, the scale of current supply projects remains minimal in contrast to the pressing need to accelerate production and infrastructure availability. At the end of 2022, the global supply capacity of low carbon hydrogen stood at 3.2 million tonnes per annum (MTPA), with most of the capacity coming from blue hydrogen, and biomethane stood close to 7 Bcm. However, recent policy introductions, such as the Inflation Reduction Act (IRA) in the United States and the European hydrogen bank, have improved the economic viability of all hydrogen types, supporting the acceleration of desired hydrogen supplies. Europe and the United States maintain their leading positions in biomethane production, producing about 6.1 Bcm combined as of September 2023 – Europe has ambitions to increase biomethane production to 35 Bcm by 2030, compared to 2021 level of around 3.5 Bcm. Meanwhile, China's biomethane capacity buildout has fallen short of projections. CCUS is expected to grow sevenfold, from around 50 MTPA in 2023 to 370 MTPA by 2033.

Figure 7: Clean hydrogen cumulative capacity by status, including pre-FID projects (2010 – 2030)[2]



Source: Rystad Energy

The growth of renewable energy sources within the power mix is directly correlated with a growing need for reliable, dispatchable, and flexible capacity resources to balance grids during periods of renewable energy sources intermittency. Gas-fired generation is a critical source of long-duration flexibility, as opposed to short-term balancing which can be effectively delivered through batteries. Gas is the most cost-effective grid resilience resource, and high renewable energy sources capacity additions will likely require pairing with gas-fired generation capacity to maintain grid security. The level of gas-fired generation would vary, based on the pace of the energy transition in different countries and regions. Emerging economies, such as those in Africa where general energy poverty is still high, and in Asia where coal plants still dominate, gas presents a stable and sustainable alternative to energise economies while lowering the carbon intensity of the grids. When these countries move towards adoption of intermittent renewable energy sources, their grids can also be balanced with dispatchable gas generation. In Africa, even regions with high levels of access have weak and unstable grids, frequently suffering from outages. These electricity grids would require additional reinforcement and flexible capacity to integrate large-scale renewables without risking a collapse.

China is the largest energy consumer in the world and is expected to remain a natural gas demand powerhouse, as gas represents a key pillar of its decarbonisation policy - forecasting that gas imports will make up a significant share of its future gas needs. In 2022, natural gas represented 8% of China's energy mix while coal supplied 56% of the country's energy consumption. China plans to increase natural gas' share in its energy mix significantly. Natural gas power generation is expected to increase alongside renewable energy generation, from 0.3 PWh hours in 2022 to 0.6 PWh in 2030 and 0.8 PWh in 2040. The additional gas-fired capacity acts as a backup and dispatchable energy source in the event of a shortage of renewable power generation, enabling China to call on a stable source of energy with quick ramp-up capability. China's existing gas-fired power generation capacity of 115 GW is primed to nearly triple by 2040 to 330 GW, which will equal to around 380 Bcm of gas per annum.

[2] Most blue and green hydrogen capacities are located in China, Saudi Arabia, and the United States of which approximately 96% involve green hydrogen. One-third of the pre-FID pipeline is blue hydrogen, which signals a call for further natural gas demand. Given the substantial size of the pre-FID pipeline and the gradual pace of FID decisions, the progress of low carbon hydrogen projects has been relatively slow.

Executive summary

Effective capacity assurance mechanisms will be imperative to sustain a rapid and orderly energy transition, requiring planning and market attributes to promote the stability of electrical grid development. Capacity mechanisms, akin to insurance for grid stability, are designed to ensure adequate supply being available to meet demand peaks. Short-term capacity mechanisms compensate electricity generators for being available in reserve and on-call, even if not always operational. Long-term mechanisms can involve central planning and procurements, or market-based capacity auctions to secure investment for future supply in anticipation of demand growth needs. The latter is particularly important because of the long lead time required for building new electricity generation and network infrastructure that cannot react quickly enough to real-time market signals.

LNG has unmatched scalability and flexibility, which makes it fundamental as a critical global enabler of resiliency through the energy transition. The surging share of renewable energy coming through the energy transition will intensify the need for responsive and dispatchable balancing sources, with natural gas, and low carbon and renewable gases playing a key role for long intermittency and peak periods (while batteries are expected to fulfil most of the balancing needs for shorter duration periods). In addition to the dispatchable characteristics of natural gas, its conversion to LNG introduces scalability and accessibility. The dynamic distribution modes of LNG, centring primarily around shipping, but also increasingly trucks in smaller-scales, function as "virtual pipelines", supplying developing regions and remote areas where piped gas is not a viable option. This often reduces emissions and improves air quality due to the replacement of higher-emitting sources like coal and gasoil. The flexibility of LNG has been displayed on numerous occasions - particularly during the war in Ukraine, when the United States increased its exports to Europe by 159% from 2021 to 2022. LNG is effective at democratising energy in developing regions and in remote areas with scarce natural resources. The adoption of small-scale LNG (ssLNG) bears lower capital investments and shorter lead times, offering new opportunities for the gas producing areas of the world.

New infrastructure investments should be designed to ensure compatibility with low carbon and renewables gases. Future proofing investments in gas and LNG infrastructure will ensure project longevity, guaranteeing long-term asset use in parallel with the growing adoption of low carbon and renewable gases. For instance, biomethane and synthetic methane can be liquified and can leverage existing natural gas infrastructure. The potential of utilising existing LNG infrastructure for liquid hydrogen carriers like ammonia or liquid hydrogen is gaining traction with rising investments and R&D efforts.

1 / Review of the most turbulent year in the history of gas

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2022 brought about a seismic shift in the global gas market, predominantly due to the dramatic reduction of Russian pipeline gas exports to Europe. Gas prices in Europe and Asia soared to historic highs, with a significant surge in European LNG demand pushing prices above those of Asian benchmarks, thereby establishing them as the highest ever recorded worldwide. Domestically, at the wholesale level, natural gas prices were at historic highs in all regions except North America and Russia. 2022 proved to be a year that would leave a lasting mark on the gas sector, with trends continuing into September 2023. The global gas market has sustained through the 2022 emergency and is now in the second half of 2023 entering into a phase of unstable equilibrium – prices remain elevated and highly fragile, but much lower than what was observed in 2022.

In this chapter, we delve into the developments that unfolded from the second quarter of 2022 until September 2023, offering a comprehensive overview and analysis of the forces at play and their impact on the global gas market.

Highlights

- **Global gas demand was 3,995 Bcm in 2022, having decreased by about 60 Bcm or 1.5% year-on-year, mainly due to prices spiking. The first half of 2023 saw mixed demand signals with growth mainly driven by the United States and China, offsetting major declines in Europe and other parts of East Asia.** In 2022, reduced Russian supply, amidst an already tight market which was set in 2021, led to record price hikes causing increasing fuel switching and industrial shutdowns, thereby reducing demand. Growth in renewable energy and a dip in gas use for heating and cooling thanks to milder weather conditions in 2022 further reduced overall gas demand.

- **Global gas production in 2022 was relatively flat, increasing by about 8.3 Bcm or less than 0.5%. The first half of 2023 saw a mild revival in the global gas supply, yet the net result of the year is still uncertain.** The flat development in 2022 was primarily driven by significant reductions of about 87.2 Bcm in Russian gas production, offset by substantial increases in North America of about 53.1 Bcm.

Table 1: Key year-on-year changes in global gas market from 2021-2022

	Consumption		Production		Gross imports		Gross exports	
Regions	Bcm	% change	Bcm	% change	Bcm	% change	Bcm	% change
Asia	− 18.9	− 2.0%	+ 16.4	+ 2.4%	− 33.2	− 7.1%	− 6.7	− 3.9%
Europe	− 66.1	− 11.9%	+ 8.6	+ 3.8%	+ 59.0	+ 11.5%	+ 79.8	+ 38.8%
North America	+ 49.4	+ 4.6%	+ 53.1	+ 4.6%	+ 2.9	+ 1.7%	+ 13.1	+ 5.0%
South America	− 10.4	− 6.6%	+ 4.1	+ 2.8%	− 14.5	− 35.9%	+ 1.6	+ 5.6%
Africa	+ 5.2	+ 3.1%	− 2.9	− 1.1%	+ 1.8	+ 13.5%	− 6.7	− 6.4%
Middle East	+ 2.6	+ 0.4%	+ 16.9	+ 2.5%	− 8.1	− 7.7%	+ 5.5	+ 3.2%
Russia	− 23.3	− 4.9%	− 87.2	− 12.3%	− 7.0	− 46.5%	− 86.4	− 34.2%
Australia	+ 1.7	+ 3.3%	− 0.7	− 0.4%	0.0	0%	+ 0.7	+ 0.6%
World	− 59.8	− 1.5%	+ 8.3	+ 0.2%	+ 0.9	+ 0.1%	+ 0.9	+ 0.1%

Source: Rystad Energy

1 / Review of the most turbulent year in the history of gas

- **2022 saw a steep reduction in available pipeline gas in Europe, resulting in an approximate 65% increase in LNG imports to compensate for lost volumes, with this trend continuing into 2023.** Abrupt changes of Russian pipeline flows triggered fierce competition for supply, mainly between Europe and Asia, causing prices to spike to all-time highs. In Europe, the sudden increase in LNG imports led to regasification facilities being overutilised over extended periods and significant inter-regional price differentials caused by infrastructure limitations. On the exporting side, final investment decision (FID) activity, especially North America, showed strong growth in liquefaction facilities for further exports. Considering REPowerEU's requirement to maintain minimum gas storage stocks, Europe saw robust growth in gas storage buildup, remaining strong in September 2023. Globally, LNG SPA contracts signed in 2022 demonstrated a sustained emphasis in the market on long-term commitments, while Europe continued to prefer short-term mechanisms.

- **In 2022, gas prices reached unprecedented levels and exhibited extreme volatility, with the TTF and LNG Northeast Asian peaking at around 90 USD/MMBtu and 60 USD/MMBtu respectively. Although volatility has toned down in 2023, the TTF still registers roughly three times higher average prices and five times higher average volatility compared to pre-covid and pre-energy crises levels in 2019.** There was a visible deviation between gas prices in some regions due to infrastructure constraints in moving the gas from abundant areas to those in demand. The soaring gas prices seen in 2022 inflicted severe damage on numerous sectors, resulting in industrial shutdowns, economic downturns, and power blackouts, with the consequences still being felt in September 2023. Gas prices remain fragile with limited supply coming on stream in the coming years.

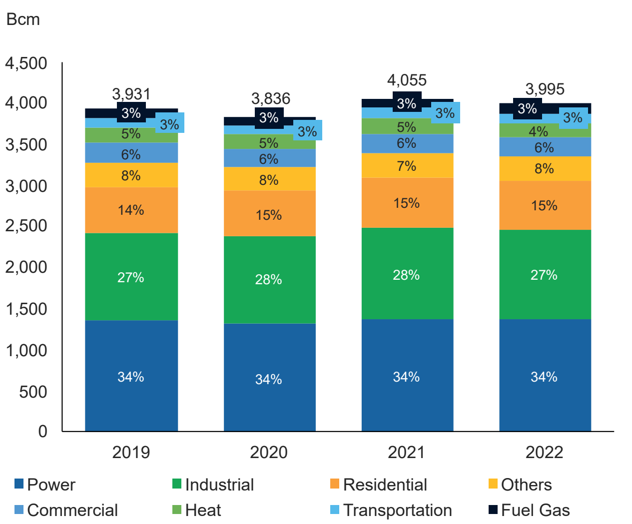
- **Due to the high gas prices in Europe and Asia, the economic attractiveness of coal improved in 2022, resulting in increased consumption through gas-to-coal switching and a corresponding growth in emissions. Europe's and Asia's coal consumption for power generation increased by 1.3% and 2.6%, respectively.** The price spikes in Asia and Europe caused the Asian spot and TTF to raise above their respective gas-to-coal-switching bands for the majority of 2022, making coal a lot more attractive. In the context of power, coal consumption increased even as overall power consumption declined. Subsequently, the emission intensity of global power production increased in 2022. This occurred despite record growth in renewables generation, without which the increase would have been even worse. Leading up to September 2023, the economic justification for coal switching in Asia and Europe has weakened as gas prices have decreased.

- **While low carbon gases are still small in scale, growth has been improving, albeit still falling significantly behind the needed decarbonisation trajectory. Thus, aggressive action is required to scale up the supply of low carbon gases if the said targets are to be met.** Globally, policies have been improving the economic viability of all hydrogen types, although green hydrogen is generally the most favoured by policy support measures. While green hydrogen saw its nameplate capacity double, blue hydrogen saw limited growth considering spiking natural gas prices. Europe and the United States maintain their leading positions in the renewable natural gas or biomethane production, whereas China's capacity buildout falls short of general projections. In September 2023, biomethane accounted for approximately 0.2% of the natural gas global market share, which falls significantly short of the potential.

- **The supply shock coming out of the Russia-Ukraine war reminded the world about the need to re-focus on energy security and underscored the need for reliable and diversified energy sources. Moving forward, a more integrated approach on the three dimensions of the energy trilemma is essential.** The developments observed in 2022 and the first half of 2023 demonstrate that when energy security and affordability are compromised, short-term crisis response measures prioritise security over sustainability. Hence, gas emerges as a key energy source needed to balance the energy trilemma towards an equilibrium encompassing all three dimensions: security of supply, sustainability, and affordability. Not only is gas abundant and affordable when timely investments are made, but it also has a lower carbon footprint than other fossil fuel alternatives even when unabated. Moreover, the gas system can be further decarbonised with the use of carbon capture and with the scaling of biomethane and other low carbon gases.

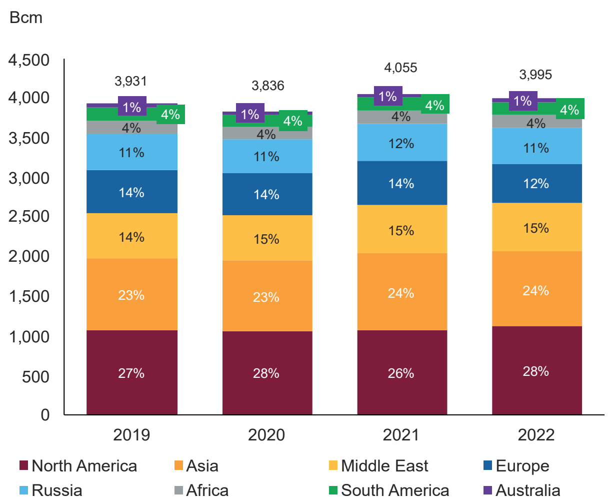
Developments in gas demand

Figure 8: Global gas demand, split by demand sector



Source: Rystad Energy

Figure 9: Global gas demand, split by region

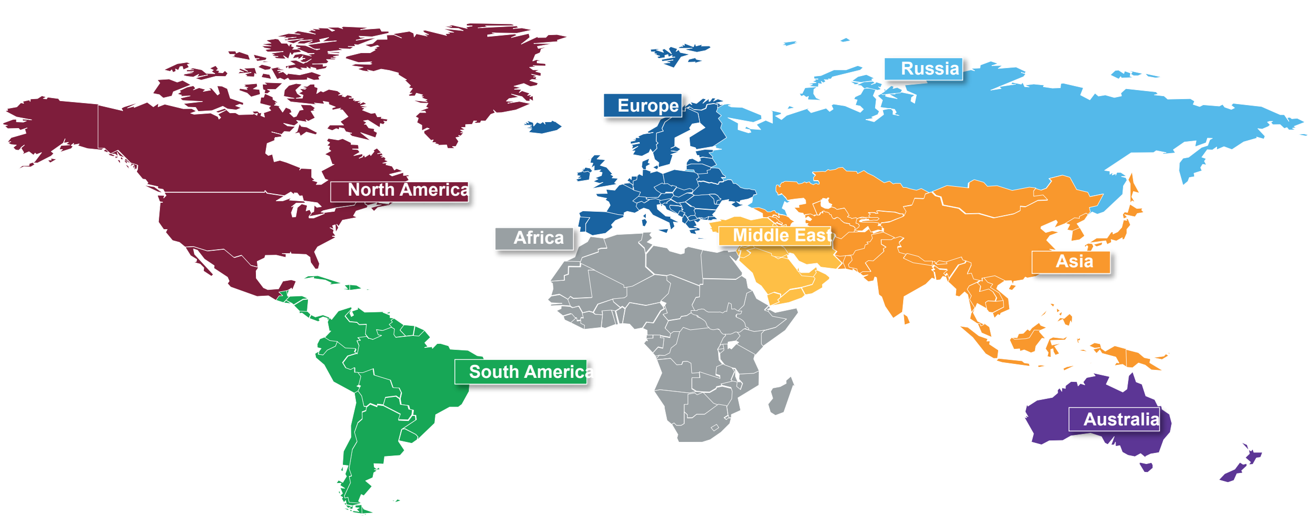


Source: Rystad Energy

Global gas demand decreased by about 60 Bcm (1.5%) overall in 2022 compared to 2021, although still being above the pre-Covid year 2019. The main drivers of the decrease were increased gas-to-coal switching and industrial shutdowns in response to higher prices, coupled with growth in renewable energy and a dip in gas use for heating and cooling in many parts of the world due to mild weather conditions. In terms of prices, the TTF gas price reached an all-time high in 2022 of about 90 USD/MMBtu, mainly attributable to significant reductions in Russian production and exports to Europe of about 87.2 Bcm and 79.8 Bcm respectively.

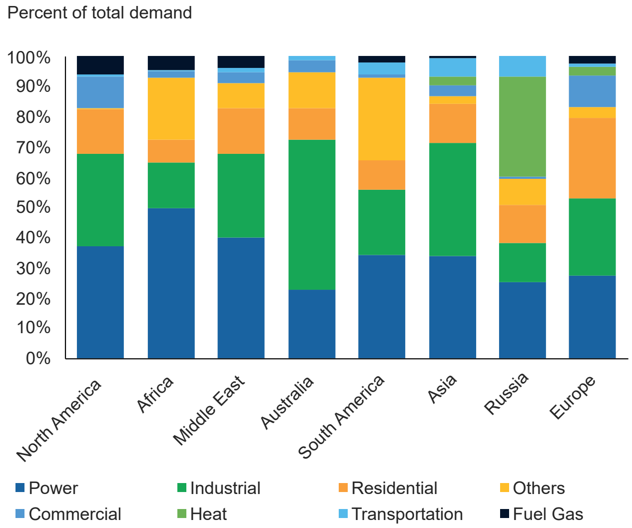
Despite a relatively stable gas demand sector mix on a global scale in 2022, regional changes in gas consumption from 2021 were evident. The demand decline in 2022 was particularly pronounced

Figure 10: World map coloured by regions



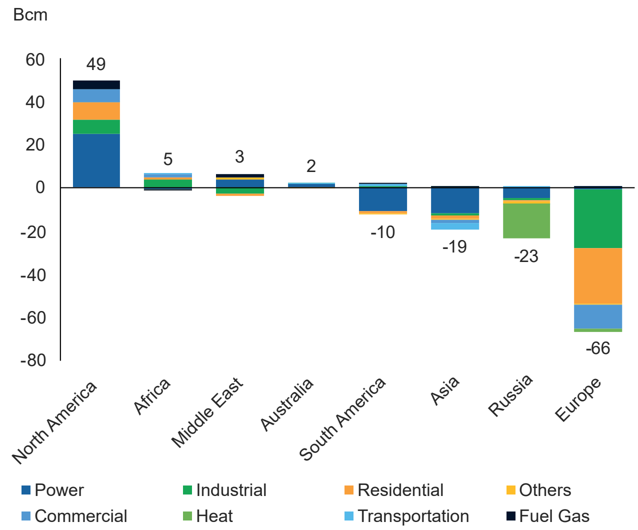
Source: Rystad Energy

Figure 11: Gas demand sector mix in 2022, split by region



Source: Rystad Energy

Figure 12: Global gas demand sector year-on-year change, split by region (2021 – 2022)



Source: Rystad Energy

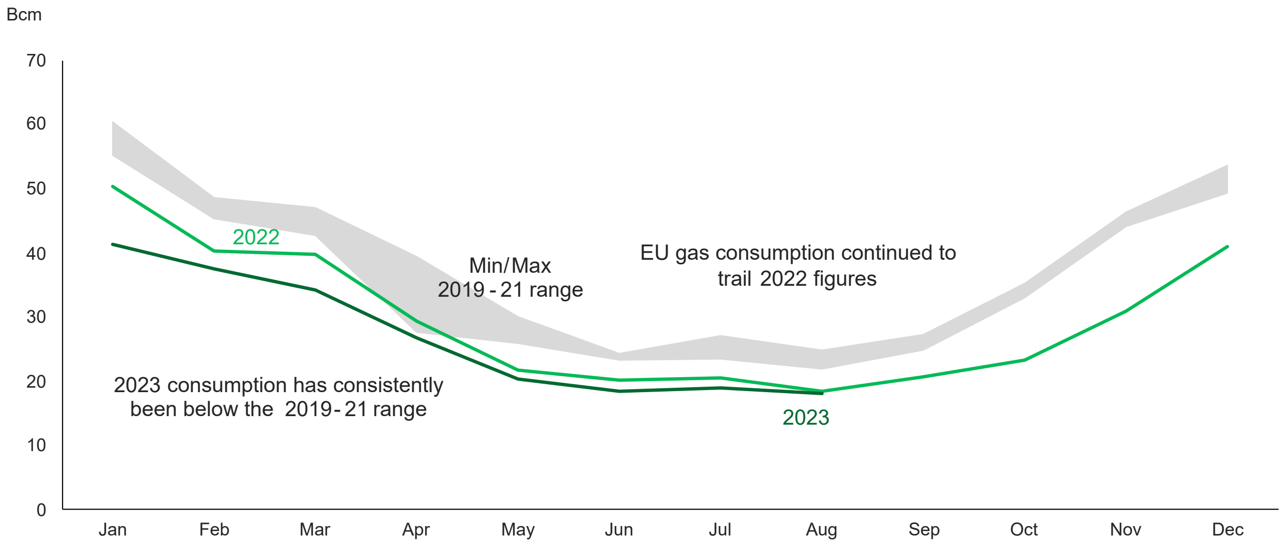
in Europe, caused by market disruptions resulting from the Russia-Ukraine conflict. Further, Asia's previously robust growth trajectory saw stagnation, primarily caused by elevated gas prices and subsequent demand destruction. By contrast, North America saw a notable increase in year-on-year gas demand in 2022.

Europe saw the steepest demand reduction globally in 2022 of about 66.1 Bcm, equalling a 12.0% contraction from 2021. The major drivers of this reduction were reduced industrial consumption and decreased residential and commercial usage. Although industrial consumption is typically stable, elevated gas prices in 2022 caused industry shutdowns in Europe, accounting for about 41.5% of the region's total demand contraction. For instance, in September 2022, Yara International, a Norwegian chemical company and a major global fertilizer producer announced reductions in ammonia production in Europe due to rising gas prices. Additionally, some industrial players adopted the strategy of switching from producing themselves to importing cheaper finished commodities and intermediary goods. Consequently, by mid-2022, Germany's chemical industry reportedly, according to the European Central Bank, began importing ammonia instead of producing it domestically. Furthermore, Europe's extensive gas distribution networks for residential and commercial buildings saw a substantial decrease in gas demand, accounting for about 55.6% of the region's total demand contraction. According to the IEA, over 60% of the decrease in residential and commercial buildings can be mostly attributed to mild winter temperatures, while the adoption of about 2.8 million heat pumps coupled with increased use of electricity to heat buildings reduced the gas demand by an additional estimated 1.4 Bcm. Despite increased electricity-based heating, Europe's power sector faced a compounded supply challenge in 2022. In addition to the gas supply constraint stemming from Russian pipeline curtailments, Europe experienced a drop in nuclear power generation due to facility downtime, as well as limited hydropower generation. These factors together created significant stress in the power sector. Regardless, the gap was partially met by robust growth in non-hydro renewables, coal switching, and the mild winter temperatures, resulting in unchanged gas demand for power in 2022.

The substantial reduction in gas demand observed in Europe during 2022 raises the question: is the decline fleeting or indicative of a lasting trend?

Although some price-driven trends such as industrial shutdowns are reversible, 2023 September shows no clear indication of recovery in the gas demand by Europe's biggest consuming nations, even though the cost situation has improved, and prices have retreated. However, the prices remain above pre-crisis levels and fear of returned volatility is still present. Gas consumption in the EU from January to August 2023 was around 215 Bcm, a reduction of about 25 Bcm from the same period in 2022. When compared with EU's pre-crisis gas consumption in the first eight months in 2021, the decrease is even more significant, totalling over 53 Bcm. However, it is still too early to definitively determine whether

Figure 13: EU27 monthly gas consumption



Source: Eurostat; Rystad Energy

the reduction represents a permanent shift in demand. There is a high degree of uncertainty surrounding whether the decreased demand is solely driven by pricing factors, or if it signifies a more enduring trend. Nevertheless, the evidence observed up until August 2023 indicates that there may be lasting changes in gas demand.

Russia too saw a demand reduction of 23.3 Bcm or 4.9%, largely attributed to a mild winter[3]. As seen in Figure 12, Russia's gas consumption mix stands out since its heating relies heavily on gas-powered centralised heating systems. Although Europe and parts of Asia have similar systems in operation, most regions apart from Russia predominantly rely on electricity and distribution of piped gas and local heat boilers for heating. Consequently, during the warm winter of 2022, Russia was the only affected region to see significant reductions in gas usage for such heating purposes, accounting for about 71.1% of the region's total demand contraction. The decline in Russia's natural gas demand for power generation can primarily be attributed to the expansion of nuclear energy and the development of various renewable energy sources.

In Asia, gas demand fell by about 2.0% from 963.3 Bcm in 2021 to 944.4 Bcm in 2022, mainly driven by high LNG prices, prolonged pandemic-related lockdowns in China, and a milder winter in Northeast Asia. The high LNG prices, driven by a surge in LNG demand in Europe to replace Russian piped-gas supplies, triggered demand destruction of LNG in Asia. It pushed countries with relatively weak purchasing power, like Bangladesh and Pakistan, to attempt to switch to highly emitting energy sources like fuel oil and coal, resulting in a 12% and 15% reduction in gas demand, respectively. This challenge persisted from 2022 and continues into September 2023, particularly in meeting power demand. Although Pakistan and Bangladesh contemplated turning to alternative fuels to sustain power generation, Pakistan faced issues related to its older oil-fired power plants, which are less efficient and more costly to operate compared to newer gas-fired plants, while Bangladesh faced constraints due to shortages in alternative fuel sources. Ultimately, these challenges resulted in power blackouts in both countries, dealing a harsh blow to their economies and living conditions.

In China, continued lockdown measures and reduced gas demand from price-sensitive industrial players resulted in a decline of natural gas demand by 0.8% from 370 Bcm to 367 Bcm, which is the first drop in gas demand in 30 years. Furthermore, the mild winter in Northeast Asia reduced space heating requirements and dampened gas consumption, contributing to the overall decline in Asia's gas demand. Recent developments in Asia have signalled possible divergence between policies supporting growth in coal to gas switching and the continuing expansion of coal. In 2022, China approved a

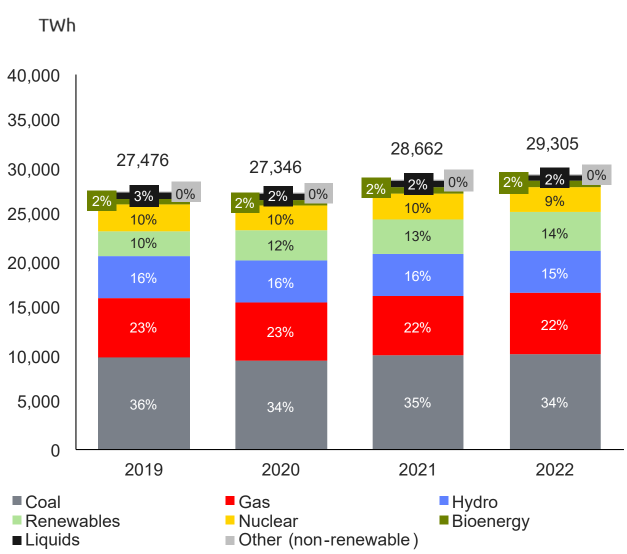
[3] *Transparency on Russian figures have been reduced post the onset of the Russia-Ukraine war, yet Rystad Energy believes the fall is real and attributable to heating and power.*

record-breaking 86 GW of new coal-fired plants, while other countries like Pakistan pledged to quadruple its coal-fired generation from 2 GW in 2022 to 10 GW by 2030. This would undermine energy transition targets like "peak emissions 2030" for China and "50% reduction of emissions by 2030" for Pakistan, which require gas to progress towards decarbonisation goals, and at the same time meet industrialisation needs. This has resulted in much uncertainty surrounding Asia's future gas demand and the overall energy landscape, as the switch back to coal deviates away from sustainability and could potentially set emerging economies in Asia back in terms of industrialisation and risk significant delays in local decarbonisation efforts and global net-zero targets.

In the first half of 2023, China saw gas demand recovering and growing at 5.6% year-on-year to reach 194 Bcm, largely attributable to fully reopening its economy from the Covid lockdowns. China's total LNG and pipeline imports increased by 5.8% from 2022, reaching 76 Bcm. Nonetheless, its imports are still lower than the 81 Bcm pre-crisis level in the first half of 2021, due to China's efforts in boosting domestic gas production and a mild economic rebound. In contrast, Japan saw gas consumption and LNG imports decreasing 9% to 48 Bcm in 2022 and 14% to 33 Bcm year-on-year in the first half of 2023. In 2021, before the Russia-Ukraine crisis, Japan's LNG imports amounted to 53 Bcm. The drop from 2022 is attributable to Japan's expanded nuclear and solar generation capacity and a high 5.4 million tonnes inventory level by June 2023. Before the 2023/24 winter season, Japan, and South Korea plan to have an additional combined 6 GW of nuclear capacity online, further softening their demand for LNG due to less dependence on gas-fired power generation.

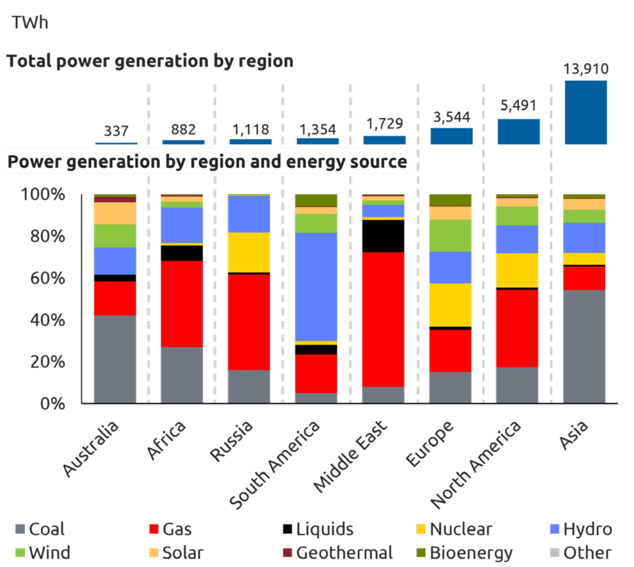
North America's gas demand by contrast grew by 4.8% or 49 Bcm year-on-year in 2022, a notable increase driven primarily by increased utilisation of gas for power generation as well as residential and commercial applications. In the power sector, this was largely due to the retirement of coal-fired plants, relatively higher coal prices, and below-average coal stocks. Consequently, there was a noticeable shift towards increased utilisation of gas for power generation. Additionally, the United States experienced record-high temperatures in summer of 2022, boosting power demand for cooling. In the residential and commercial sectors, colder-than-average temperatures in January 2022 resulted in increased demand from gas boilers for space heating in residential and commercial buildings. In 2023, the gas market experienced a dent in demand primarily in residential and commercial sectors for heating during the mild winter in the northern hemisphere. Conversely, there was also a rise in electricity generation for cooling when heatwaves affected large parts of the same region. For example, in the United States, the gas consumption in the residential and commercial sectors dropped

Figure 14.1: Global power mix split by energy source



Source: Rystad Energy

Figure 14.2: 2022 global power mix by region, split by energy source



Source: Rystad Energy

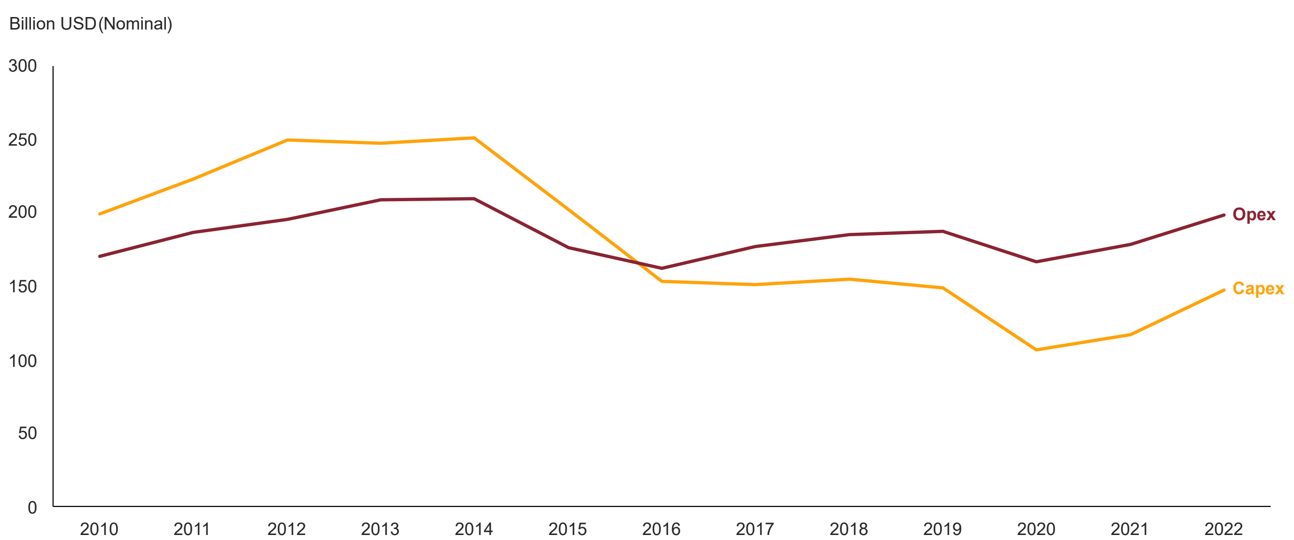
by 9% year-on-year to 3.2 Bcm in the first quarter, while consumption in electricity generation rose to 33.2 Bcm in June, a 2.3% increase from June 2022.

South America's gas consumption reduced by 6.6% or 10 Bcm in 2022, from 159 Bcm in 2021, due to improvements in hydroelectricity generation conditions in Brazil and lower demand from the industrial sector amid high gas import prices. Conversely, Africa's gas demand saw a 3.1% or 5 Bcm increase in 2022, compared to 167 Bcm in 2021, primarily due to increased needs within the power and industrial sectors and ongoing efforts to democratise energy and gas to bolster economic development. In the Middle East, gas demand increased modestly from 612 Bcm in 2021 to 615 Bcm in 2022, driven by higher electricity demand and improved gas supply for power generation. Australia witnessed a slight uptick of 1.6 Bcm in gas demand, despite the growth of renewables in the power mix, as coal plant closures required gas to step up as a dispatchable source.

In the context of the worldwide power mix, gas utilisation remained largely stable between 2021 and 2022, even in the face of a substantial increase in installed renewable capacity and gas-to-coal switching. Nevertheless, it is worth noting that regional disparities persist, as seen in the chart above. As discussed in the following chapters of this report, even in areas where the power sector is expected to gradually transition to large-scale renewables, the dispatchability and flexibility of gas-fired power makes it an essential part of the decarbonised power system, providing resilience and grid stability.

Supply and gas investments

Figure 15: Capex and Opex in global gas production (nominal upstream gas field-related expenditures)



Source: Rystad Energy

Turning to the supply side, we examine the evolution in investments in the cycle leading up to the energy crisis starting in 2021. There has been a pronounced downward trend in upstream investment over the previous decade, setting in after the oil downturn in 2014.

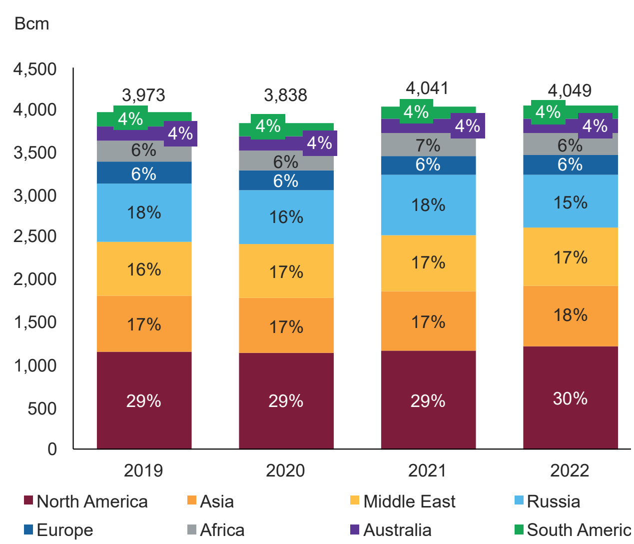
The period from 2014 to 2016 saw reduced investments in oil and gas as global oil prices declined significantly, with abundant injections of supply into the market from the strong United States shale production that was bearing fruit from investments prior to 2014. Then, from 2015 to 2019, capital expenditure stagnated due to the lingering aftermath of the oil and gas price drop accompanied with a growing policy uncertainty amidst the stronger focus on climate change mitigation. Many operators faced elevated debt and lower profits, prompting cautious investment decisions focused on cost reduction and capital discipline. This period led to many companies introducing cost saving programmes to reduce expenditure and allocate capital more efficiently. Without significant cost reductions, this period would have been much more volatile in terms of energy costs. Global average well costs fell by more than 28% from 2015 to 2021. Inflationary pressure in 2022 marked the first year of increasing unit costs, with average well costs growing by 8% year-on-year.

The decline in investments continued from 2019 to 2020, largely due to the Covid-19 pandemic. Uncertainties in future demand and policy directions led to a frugal investment stance across industries, including energy. This decline in investment levels in 2020 further compounded the previously observed trend of reduced investments since 2015. In 2020, a temporary reduction in operational expenditure can be attributed to the pandemic's disruptive effects. The recovery from the pandemic in 2021 and 2022 was marked by a sharp rebound in industrial activity, transportation, and consumption of commodities, including natural gas. Low investment into the upstream sector during this period continues to contribute to high commodity prices and energy scarcity today.

The rebound helped expenditure levels to recover in 2021 and in 2022, capital expenditure on gas fields increased by 26%, attributed to both a high inflationary environment and increased economic activity levels. Capital costs have been rising due to multiple supply chain pressures exacerbated by the crisis, tight markets for specialised labour and services, and the effect of higher energy prices on essential construction materials such as steel and cement.

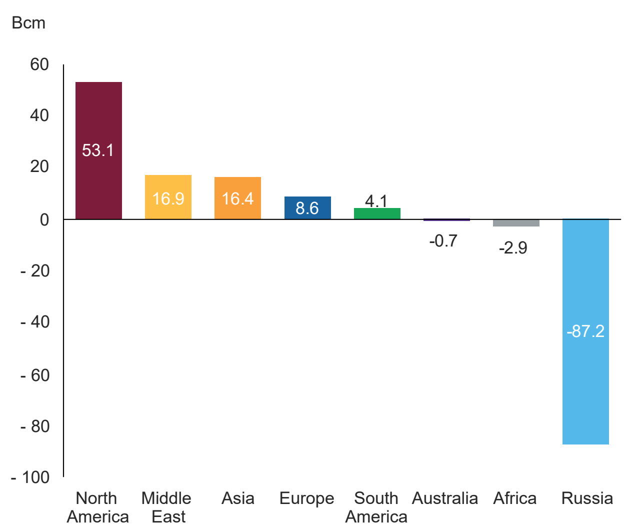
It is important to note that most of the current capital expenditure is associated with expansion projects rather than exploration in greenfield areas. Most operators are still relatively cautious and unwilling to take on increased risks associated with new exploration, due to ongoing energy transition trends, uncertainty about accessible financing and political risk, as policies continue to be issued to ban future use of natural gas. Rystad Energy's overview shows that E&P exploration budgets have been revised down from almost 160 billion USD in 2013 to around 65 billion USD in 2023, both nominal figures. This is a troubling fact, because sustained exploration and upstream investments are essential to rebalance the energy market and restore security of supply, avoid production shortages and price spikes and to enable coal replacement, that would otherwise limit and challenge environmental goals and reverse decarbonisation efforts. Consequently, in a bid to improve energy security, some countries have committed to attracting upstream investment climate to increase its domestic production of gas. Indonesia, for example, has announced an ambitious target to increase its domestic gas production from 58 Bcm in 2022 to 124 Bcm by 2030. This is in line with its goal to increase the share of natural gas in the primary energy mix from 17.8% in 2013 to 22.4% in 2025 and 25% in 2050, according to its National Energy Plan (RUEN). The upstream regulator of Indonesia, SKK Migas estimates additional annual upstream investment of 18 to 20 billion USD to fulfil the

Figure 16: Global gas production, split by region



Source: Rystad Energy

Figure 17: Global gas production year-on-year change (2021 – 2022)



Source: Rystad Energy

target. However, its fiscal regime remains as one of the most complex and stringent in the world, with government take averaging between 60% to 75%, disincentivising foreign investment to development its gas resources. Policy alignment between energy policies and regulations underpinning investment climate is especially important for developing countries like Indonesia, which is still highly reliant on coal. The development of gas resources provides a pathway to a more sustainable, secure, and affordable future, and aids its industrialisation for further economic growth.

On a global level, gas production remained relatively flat in 2022 compared to the previous year. On the other hand, on a regional level, 2022 brought a shock to local markets.

Following the Russia-Ukraine crisis, production in Russia decreased by 87.2 Bcm or 12.3% from 709.7 Bcm in 2021 to 622.5 Bcm in 2022. The reason for the decreased output is two-fold. First, the division of Russia's gas supply system into two distinct segments, one in the west and one in the east, without interconnection, posed a complication for redirecting gas exports. Consequently, lack of gas infrastructure in the east, other than solely the Power of Siberia pipeline, forced Gazprom to cut production in line with reduced gas exports to Europe. By contrast, the independent LNG producer Novatek boosted gas output in 2022, mainly thanks to its LNG portfolio which is more resilient to market turbulence. Second, the explosions in the North Stream infrastructure in September 2022 significantly diminished Russia's export capabilities to Europe. A further examination of these developments can be found under the Trade Flows section.

North America conversely increased production from 1,160 Bcm to 1,213 Bcm, an increase of about 4.6% year-on-year. About 72.8% of the increased North American production stemmed from the United States, where gas supply growth was largely driven by increased shale activity in the Permian, Haynesville, and Eagle Ford plays. Unlike Haynesville and Eagle Ford, natural gas production in the Permian is primarily the result of associated gas production from oil wells. Haynesville is a strategic location for operators to drill for natural gas because of the proximity to the Gulf Coast, where industrial demand and LNG production and export terminals have been growing.

The Middle East saw the second largest growth in gas production in 2022, rising from 670 Bcm in 2021 to 687 Bcm last year, with 40.2% and 24.1% of the increases stemming from Iran and Saudi Arabia, respectively. The significant increase stems from the region's goal to boost self-sufficiency and further export potential.

In Asia, gas production rose modestly from 695.9 Bcm in 2021 to 712.2 Bcm in 2022. Most notably, there was a significant surge in Chinese production, amounting to a remarkable increase of 12.5 Bcm. The increase is in alignment with the strategic objectives outlined in the country's latest five-year plan for 2020-2025, which seeks to bolster domestic gas production to enhance energy security. Apart from China, the region's upturn can be primarily attributed to expansions in Turkmenistan and Azerbaijan, with the rest of Asia experiencing either marginal growth or a decline in production during 2022. With the aforementioned additions, the year of 2022 marks the first time since 2013 that Asia's gas self-sufficiency rate has grown. This reversal of the trend signifies a notable shift from the past, where gas production struggled to keep up with the region's surging demand. Despite this development, imports will continue to play a crucial role in meeting demand growth in Asia.

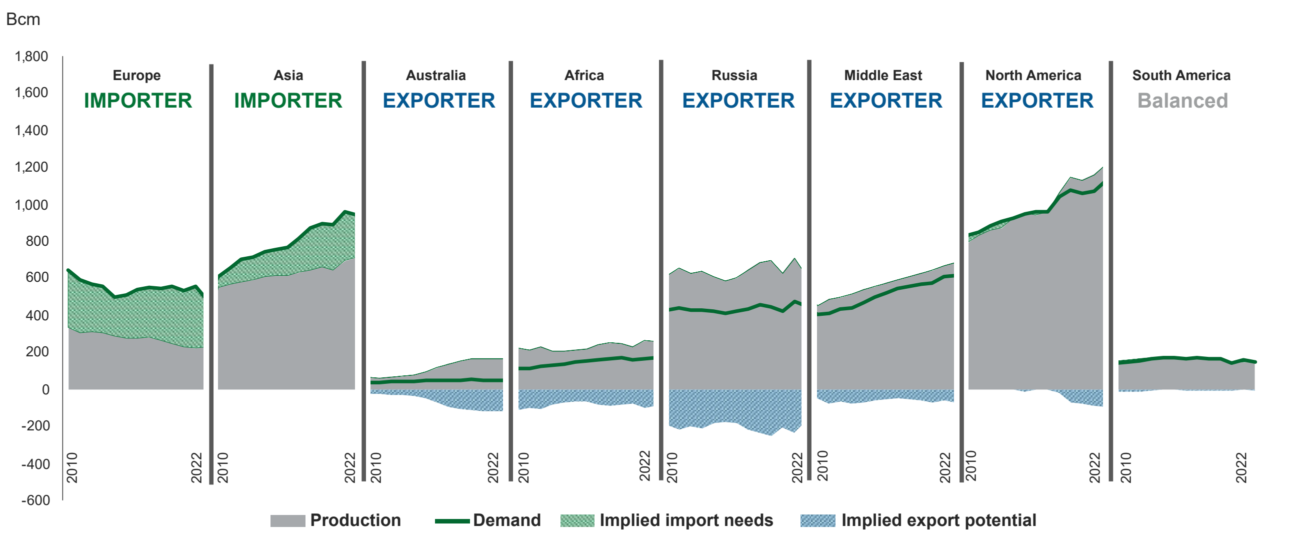
European production increased by about 8.6 Bcm in 2022, an increase of approximately 3.8%. The incremental production primarily stemmed from Norway, as the country strategically ramped up output, resulting in a remarkable increase of over 9.2 Bcm (approximately 7.5%) year-on-year. This surge was aimed at augmenting exports to continental Europe, effectively countering the decline in Russian supply. Increased production permits issued by the Norwegian Ministry of Petroleum and Energy allowed Equinor to maintain high production levels at its Troll, Oseberg and Heidrun gas fields, increasing production by around 1.6 Bcm. This was further supported by the restart of the Hammerfest LNG facility in early June 2022, with all its 40 cargoes shipped to Europe.

By contrast, Africa saw gas production dip by 2.9 Bcm (about 1.1%) between 2021 and 2022, mainly due to declining production from large, maturing fields in Egypt. However, net production increases from Algeria and Libya remained strong, increasing in total about 2.9 Bcm in 2022, partially offsetting the declines in mature field production. The potential for additional growth in the supply development in Africa is high, as the continent holds 8% of the world's gas reserves and has ambitious plans for their development. Importantly, more gas will be needed to fuel domestic industrialisation and improve modern energy access to its growing population. With 600 million Africans lacking access to electricity and with its young and fast-growing population, Africa is a good candidate for development of domestic gas markets. However, capturing this potential will require concerted effort from the key regional actors to address existing barriers such as securing capital and buildout of significant infrastructure, as well as streamlining policy and improving business climate and project delivery timelines[4]. According to the IEA, Africa's energy sector still faces challenges in rebounding from the sharp decline in oil and gas spending levels in 2014.

South America saw a modest supply growth of 4 Bcm in 2022, mainly attributable to Argentina and Peru. This region too has significant potential in the onshore resources that could be developed to meet growing local demand and even facilitate for exports.

Trade flows

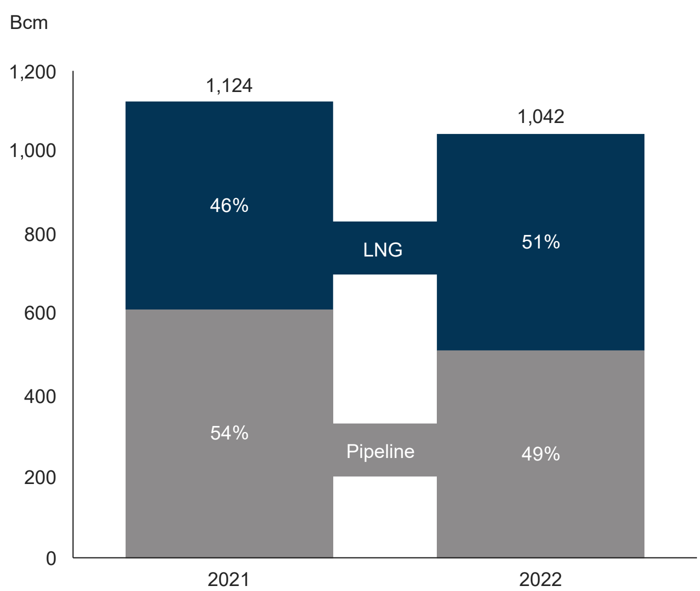
Figure 18: Gas demand, production, and import/export volumes, split by region



Source: Rystad Energy

Figure 18 illustrates the disparity in gas production and demand across various regions. Some regions exhibit a surplus of gas production over their local demand, categorising them as exporting regions, while others experience a deficit, classifying them as importing regions. In the case of exporting regions, the volume they can export without tapping into their stored gas reserves is termed the "implied export capacity". Conversely, for importing regions, the quantity they can import without resorting to their stored gas reserves is denoted as the "implied import requirements".

Figure 19: Global net gas export volumes, split by flow type



Source: Rystad Energy

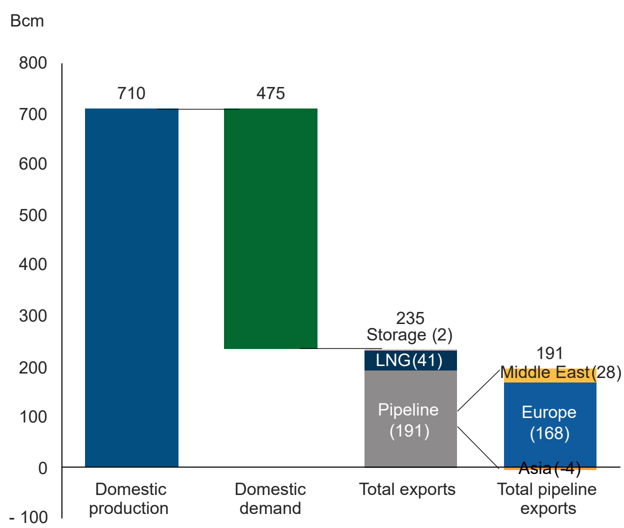
[4] IGU "Gas for Africa 2023"

1 / Review of the most turbulent year in the history of gas

As previously highlighted, the year 2022 brought substantial fluctuations in both the supply and demand of gas. These fluctuations in turn had notable consequences on global trade flows, especially for the two largest gas importing regions, Europe and Asia, and large exporting regions, namely Russia and North America, as illustrated in Figure 18. 2022 witnessed a substantial shift in the share of exports from pipeline to LNG, primarily attributed to the reduction in Russian pipeline exports following the commencement of the Russia-Ukraine war, the explosion of the Nord Stream 1 pipeline, and the surge of LNG flowing into Europe. This sub-chapter examines how the changes in Russian pipeline flows triggered cascading impacts on LNG trade patterns, influenced developments in European gas storage and infrastructure, and shaped trends in the SPA contract scene.

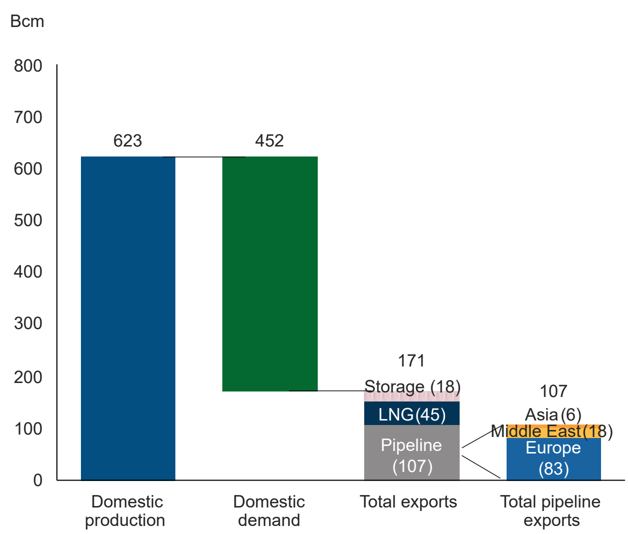
Developments in Russian pipeline trade flows

Figure 20: Russian gas flows 2021



Source: Rystad Energy

Figure 21: Russian gas flows 2022



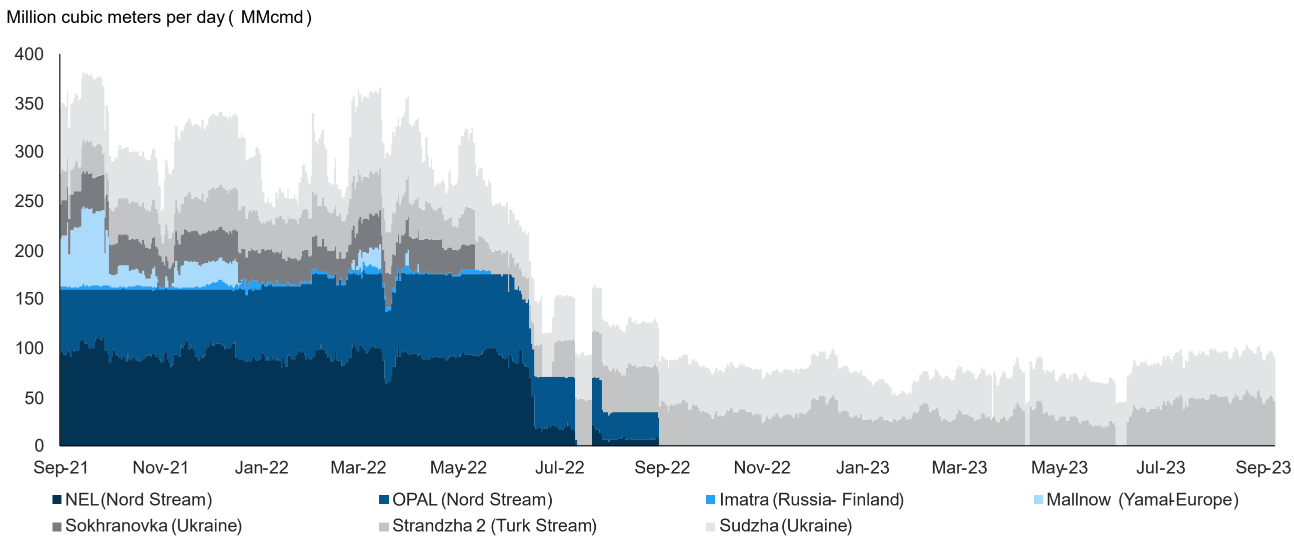
Source: Rystad Energy

In 2022, Russian production plummeted by around 87.2 Bcm amidst the war in Ukraine due to curtailments by Gazprom. In turn, net pipeline exports were reduced by about 44%, from 191 Bcm to 107 Bcm, with Europe being the most affected importing region.

Europe saw the number of operating pipeline gas supply routes from Russia reduce from six to two during 2022, which remains the case in September 2023. Consequently, more than 84 Bcm of Russian pipeline gas stopped flowing to Europe, equivalent to about 34% of European imported gas volumes and 17% of total gas consumption in the region. The largest impact came from the reduction in exports through the Nord Stream 1 pipeline. Exports through this pipeline were reduced by Russia from June 2022, before halting completely following an explosion of the Nord Stream 1 and 2 pipelines on 26 September 2022. Prior to this, Nord Stream 1 was responsible for almost 50% of Russian exports into Europe. Russian pipeline gas exports to Europe via Ukraine, totalling about 27 Bcm yearly, continued through 2022 and persist in terms of daily volumes as of September 2023, although the agreement for transits through Russia's exit point at Sudzha is due to expire on 30 December 2024. If the agreement is not renewed by Russia and Ukraine, or the flow being redirected through alternative routes via Turkey or Poland, it could reduce Russian gas pipeline flows to Europe even further.

To counter the curtailed imports, European producers attempted to maximise output within the limitations of existing infrastructure. Among the notable European production boosts, Norway, and the United Kingdom achieved production increases of 9.2 Bcm and 5.5 Bcm, reflecting year-on-year growth rates of 7.5% and 17.1%, respectively. As alternative gas pipelines to Europe were already operating close to full capacity or was constrained by upstream supply availability, Europe turned to LNG imports for the rescue, a subject covered in more detail later in this sub-chapter.

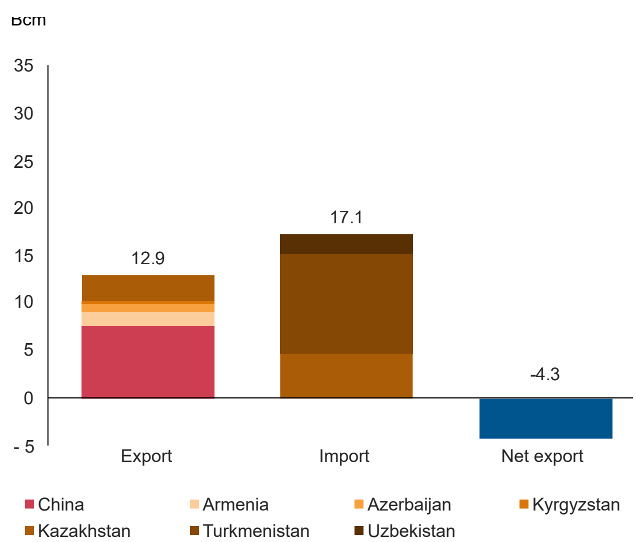
Figure 22: Russian pipeline gas flows to Europe by entry point



Source: Rystad Energy

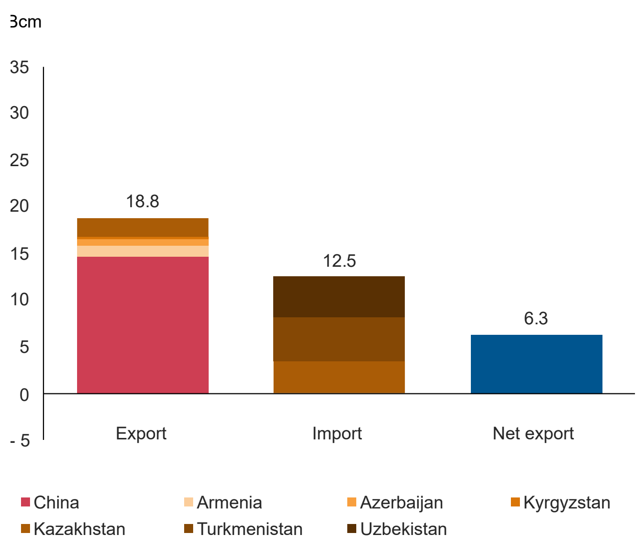
In Asia, Russia's net pipeline exports turned positive, as imports, primarily from Turkmenistan, decreased while exports, primarily to China, increased. The main contribution to this development was Power of Siberia 1 increasing pipeline exports to China by over 50%. Further, it was communicated that Russia plans to further boost exports to China by 50 Bcm annually through Power of Siberia 2, while the existing Power of Siberia 1 pipeline is set to deliver 38 Bcm per year by 2025.

Figure 23: Russian pipeline gas imports/exports with Asia 2021



Source: Rystad Energy

Figure 24: Russian pipeline gas imports/exports with Asia 2022

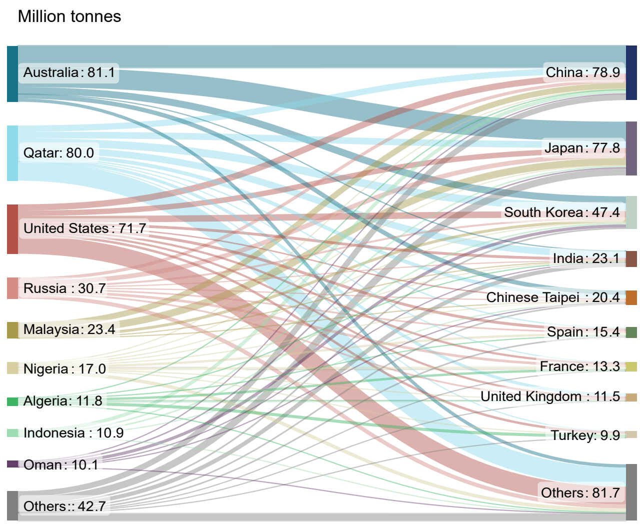


Source: Rystad Energy

Limited supply of LNG brought fierce competition

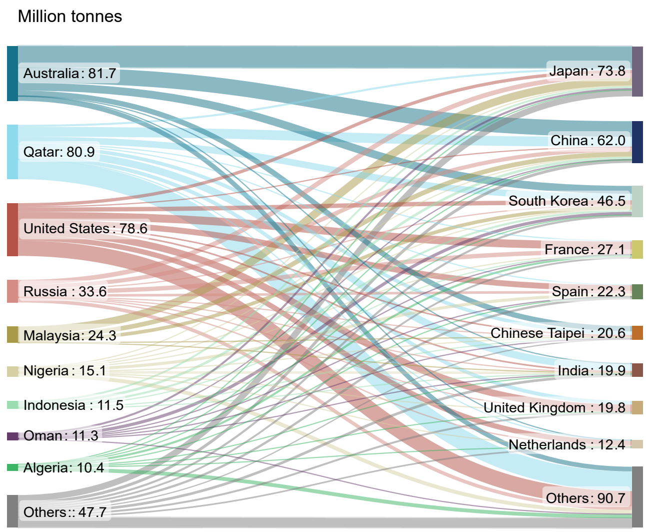
To replace all the curtailed Russian gas supply to Europe with LNG would require more than 21% of the total traded LNG globally, underscoring how profound the potential shift would be. Europe attempting to cover as much of the demand as possible brought a cascade of far-reaching effects. In 2022, roughly 13% of the world's total gas production was exported in the form of LNG, at an estimated 401.5 million tonnes. This represents an approximate 6.8% rise in LNG exports from the 375.9 million tonnes recorded in 2021. On a regional level, the most notable shift was the increased consumption of LNG in Europe. This shift was driven by a greater willingness to pay a premium price, resulting in a redirection of traded LNG, predominantly sourced from the United States, and also from Asia to Europe.

Figure 25: Global LNG trade flows 2021



Source: Rystad Energy

Figure 26: Global LNG trade flows 2022



Source: Rystad Energy

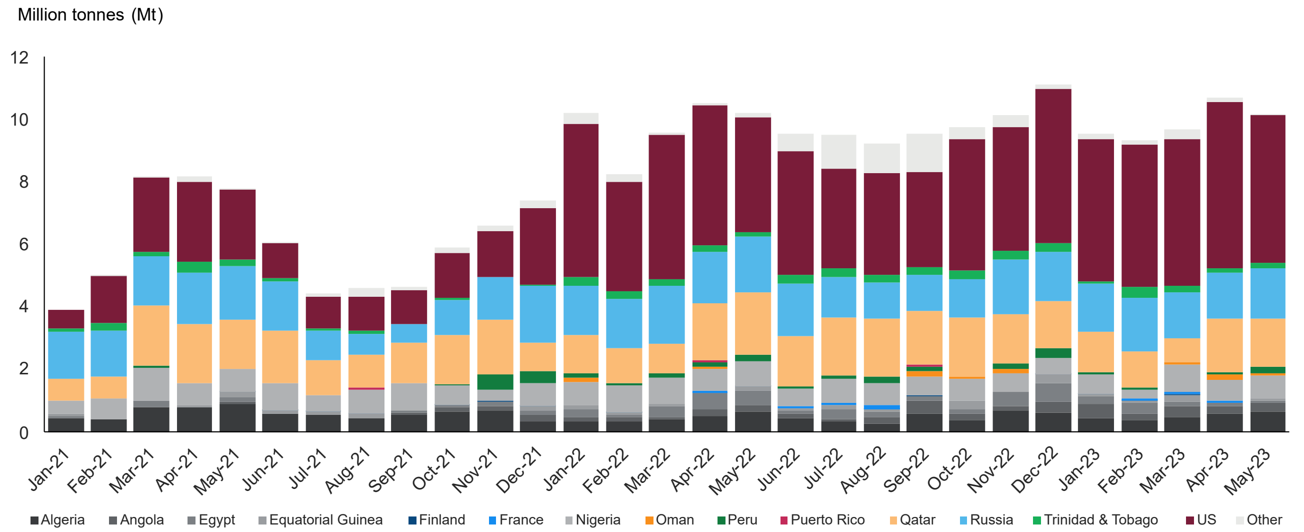
Europe saw the largest increase in imported LNG, rising from 74 million tonnes in 2021 to 124 million tonnes in 2022, an increase of almost 68%. Out of exporters to fill the European demand, the United States increased exports to Europe by more than 30 million tonnes from 2021 to 2022, a 159% year-on-year increase. Within Europe, France was the dominant LNG importer, more than doubling LNG imports from 13 million tonnes to 27 million tonnes year-on-year, of which over 64% came from the United States. Other large European importers Spain, the United Kingdom, the Netherlands, and Italy also increased LNG imports by 43%, 75%, 98% and 44% respectively in 2022, with most of the increases coming from the United States. Although gas demand in Germany was high during 2022, the country imported insignificant LNG volumes for much of the year due to a lack of regasification facilities until its first FSRU came online towards the end of 2022.

Monthly traded volumes of LNG are shown in Figure 27, with the uptick of the United States exports clearly visible at the beginning of 2022 and remaining high ever since. Qatar, Russia, and Nigeria are the next three dominant exporters of LNG to Europe, with the region's largest being France, Spain, Belgium, and the Netherlands. Significantly, despite the pipeline gas curtailments, Russian LNG exports to Europe have maintained a consistent growth trajectory, increasing by more than 260% in 2022 compared to 2018.

In Europe, the EU27 saw the largest reduction of Russian pipeline gas imports, amounting to 80 Bcm between 2021 and 2022. To offset this shortfall, there was a notable surge in gas imports predominantly from the United States in the form of LNG, and from Norway and the United Kingdom in the form of piped gas. This was further complemented by an increase in imports of Russian LNG. The collective effort managed to bridge 97% of the gap in pipeline gas supply caused by the Russian pipeline gas reductions. Even though the EU27 successfully mitigated the majority of the losses, gas consumption still decreased by around 41 Bcm and at the expense of rising coal consumption. It is worth noting that the EU27 accumulated a substantial storage buildup of 33 Bcm during that year.

As a result of Europe's surging demand for LNG in 2022, many leading importing nations in the region operated regasification facilities close to, or even exceeding, nameplate capacity for prolonged durations, as illustrated in Figure 29. For example, regasification facilities in the Netherlands saw a consistent utilisation rate over 100% in the first half of 2022, a trend which only reversed once a new import facility started operating later that year. Consequently, European newly installed regasification capacity

Figure 27: European LNG imports by origin

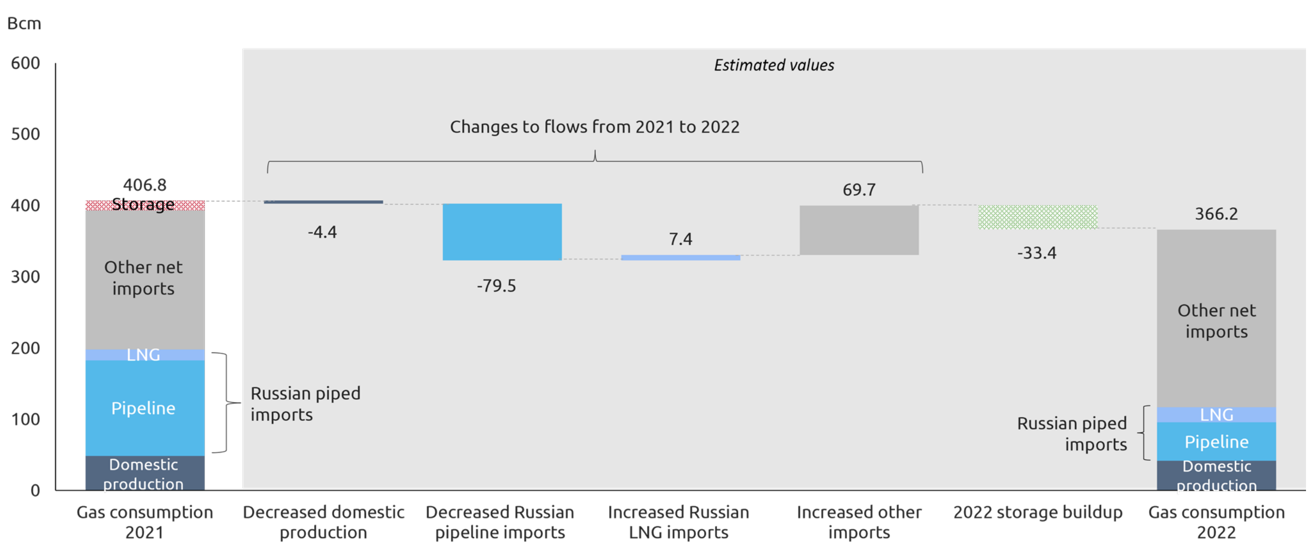


Source: Rystad Energy

grew by more than 14 million tonnes per annum (MTPA) in 2022 and about 11 MTPA so far in 2023 (as of September), a significant increase compared to earlier years. Nearly 80% and 100% respectively of new European LNG import capacity has involved FSRUs, as these have shorter lead times than traditional onshore terminals and enabled Europe to rapidly scale up import capacity to offset the declining gas pipeline flows from Russia.

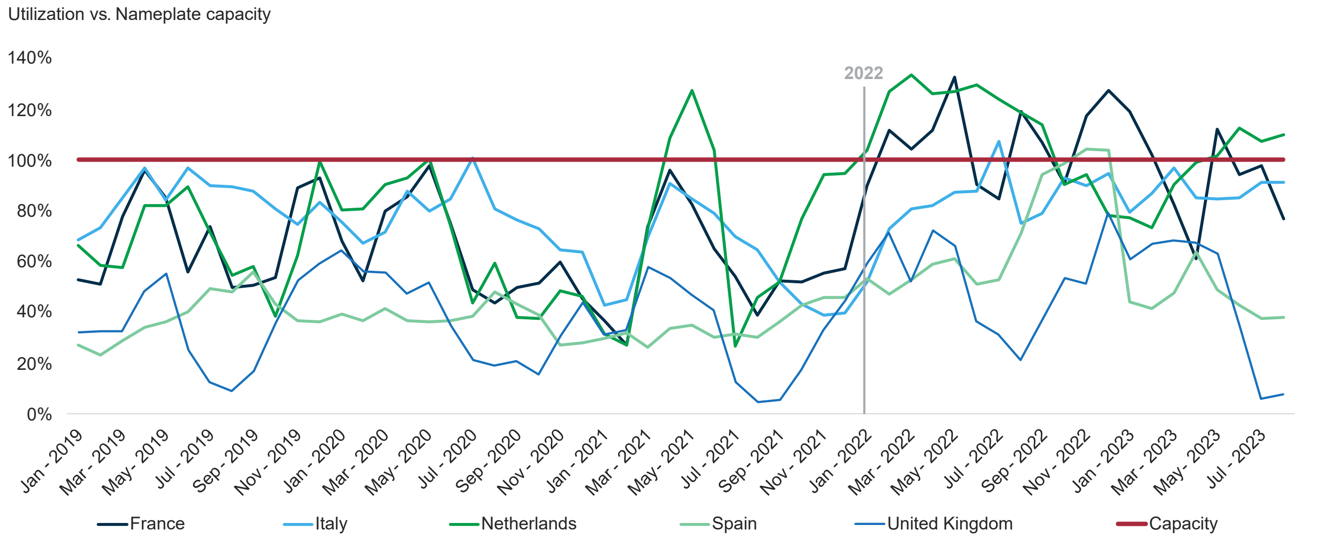
In Asia, the most significant shift in 2022 was China reducing LNG imports from Australia and the United States by 10.9 million tonnes and 10.1 million tonnes respectively, while boosting imports from Qatar by approximately 7.4 million tonnes. About 36% of the reduced Australian exports to China were redirected to Japan, with South Korea, Chinese Taipei, and Thailand accounting for approximately 51%. Conversely, a significant portion of Qatar's exports that were previously destined for Japan were redirected to China in 2022 via long-term contracts signed with Chinese gas importers. Further, during the first half of 2023, lower spot prices, higher contracted volumes, and

Figure 28: Estimated changes in EU27 gas availability from 2021 to 2022, split by source



Source: Rystad Energy

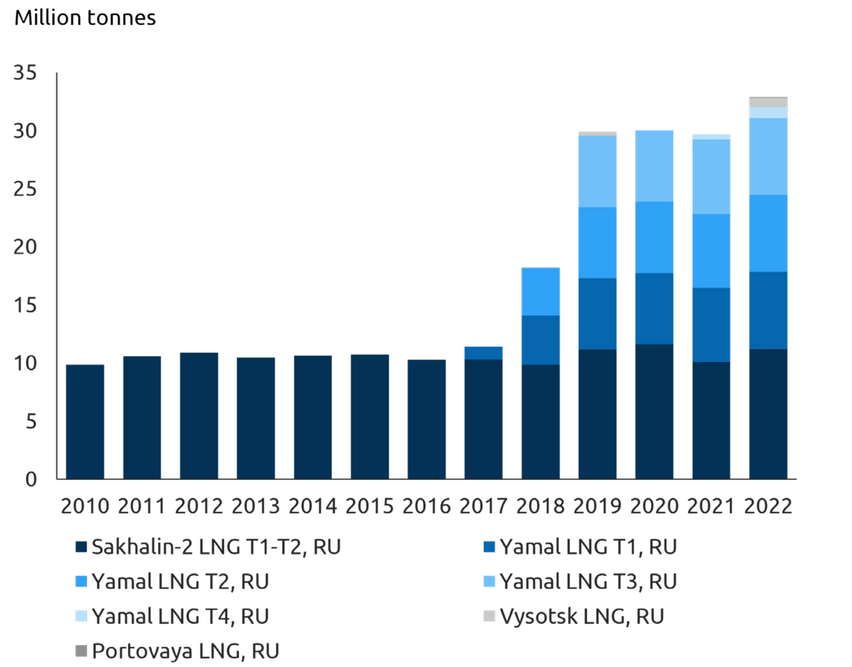
Figure 29: Regasification utilisation in selected European countries



Source: Rystad Energy

record-breaking warm temperatures led to a rise in LNG imports to China. In recent decades, Japanese entities have been acquiring equity stakes in foreign upstream gas projects and LNG developments to ensure supply into Japan. Mitsui, Mitsubishi and Inpex are the largest acquirers, with town gas companies in Tokyo and Osaka also securing a presence further down the value chain. Japanese entities have been investing significantly in Australia, the United States, Indonesia, Canada, and other areas with gas resources. Similar investments are being undertaken by Chinese operators Sinopec, CNOOC, and PetroChina which have been investing in Turkmenistan, Kazakhstan, Australia, Egypt, and other gas-rich countries.

Figure 30: Russian LNG production capacity



Source: Rystad Energy; IGU LNG Report

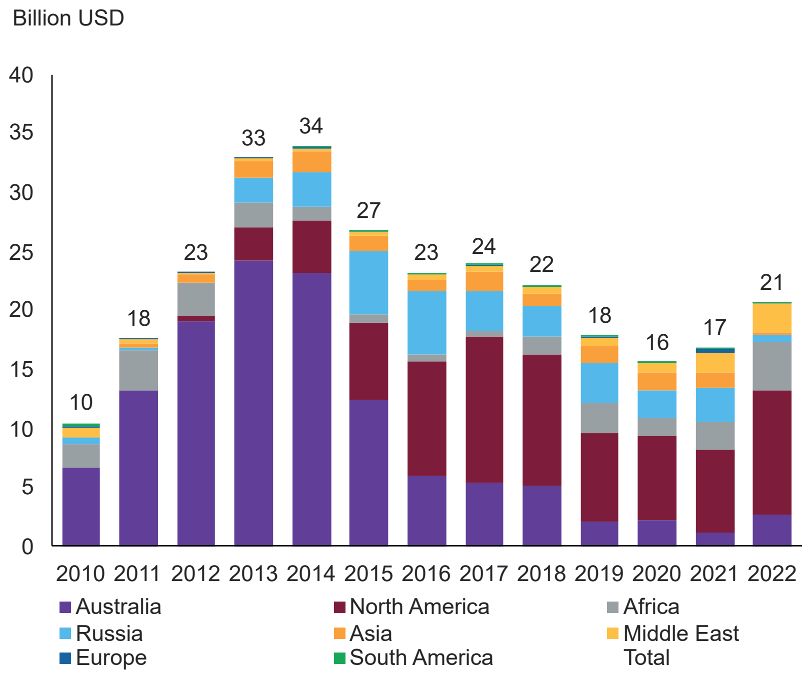
During the first half of 2023, monthly global LNG exports consistently surpassed the 2022 levels, resulting in a cumulative year-on-year increase of 4.1% and totalling 205 million tonnes. During the northern hemisphere summer, LNG supply experienced some volatility due to facility maintenance and outages. May 2023 saw the biggest month-on-month decrease primarily from producers in Qatar, Norway, and Australia, which were unable to be remedied by modest increase from Indonesia Malaysia, and Mozambique. This led global LNG exports to fall from 34.9 million tonnes in April 2023 to 32.3 million tonnes in May 2023, below the 2022 average of 33.9 million tonnes, a difference translating to about 37 cargoes. Nonetheless, LNG exports rebounded in July and kept above 33.2 million tonnes level in August. In September 2023, there have been disruption in gas supply due to rolling strikes, work bans and stoppages at the Gorgon LNG and Wheatstone facilities in Western

Australia, potentially impacting about 5% of global LNG production. Gorgon LNG has three liquefaction trains with a combined capacity of 15.6 MTPA of LNG, while Wheatstone's two LNG trains have a combined capacity of 8.9 MTPA. This poses threats if the strikes and outages last until peak winter season.

Russian LNG export volumes have been, and are still in September 2023, exported to both Asian and European buyers. Since 2017, Russia has more than tripled its LNG export capacity through the development of the Yamal LNG facilities. Further, The Portovaya LNG export terminal was completed in 2022 and is expected to contribute towards even higher LNG export capacity in 2023 which will be its first full year of production. The three trains at Arctic LNG currently in development will bolster export capacity through the northeastern passage and to Europe. Noteworthily, the second train, Arctic LNG T2, has faced delays and is currently expected to start operation in 2024. The Baltic LNG project is being developed by Gazprom in proximity to European buyers, expected to add 13 million tonnes of LNG capacity. Although previously expected to finish in 2023, the project is now facing an expected two-year delay.

Globally, liquefaction investments recovered in 2022, growing by 23% compared to 2021. Yet,

Figure 31: Global liquefaction capex, split by region



Source: Rystad Energy; IGU LNG Report

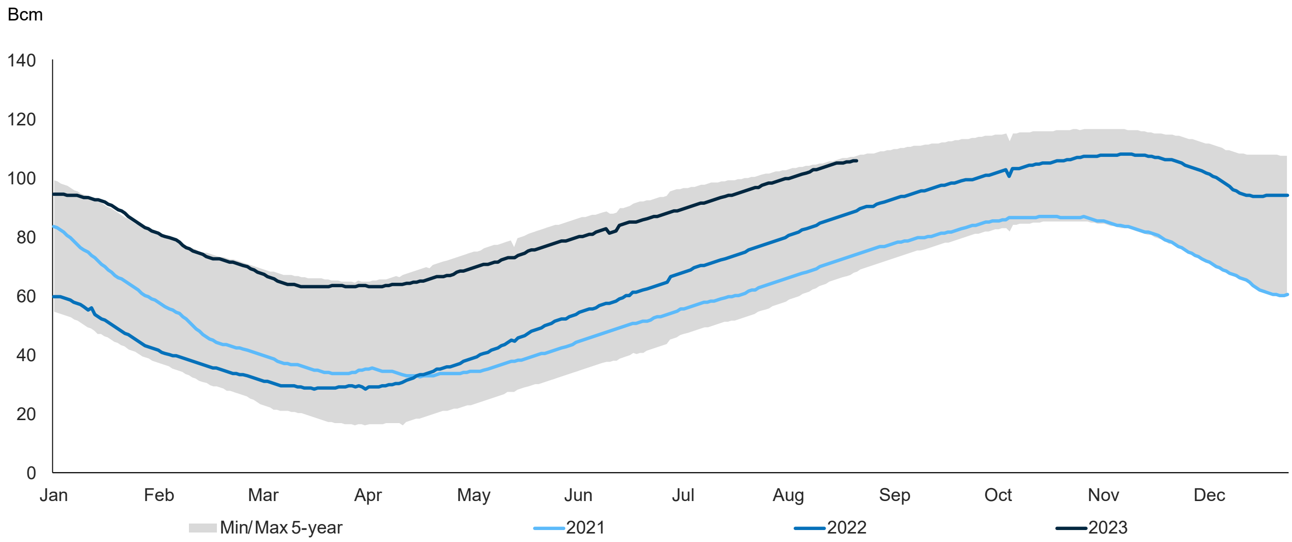
the growth additions remain significantly below the high points of 2013-14. New liquefaction investments in 2022 were mainly led by the United States, Canada, Mozambique, Australia, Qatar, and Mexico. From the beginning of 2022 to September 2023, about 81.2 MTPA of new capacity reached FID or construction, with the United States and Qatar representing about 70.6% and 19.2% of the additions respectively. In 2023, there has been a remarkable surge in newly installed capacity, as the installations by September have already exceeded the totals for each of the individual full years of 2020, 2021, and 2022. Despite growth and positive sentiments amidst current market events, significant uncertainty arouond the LNG market's future trajectory and the role of gas in the energy transition continues to weigh heavily on, and in some cases delay, investment decisions. This in turn poses significant challenges for several critical aspects, including supply security, industry development predictability, unmet demand, and pricing, among others.

European gas storage goals were surpassed

Despite tight gas balances throughout the winter of 2021/22, European storage levels rebounded in mid-2022 after the EU revised gas storage regulations to increase stocks in response to the Russia-Ukraine crisis. Through the REPowerEU initiative, the EU mandated that storage facilities should be at least 80% full by November 2022 and 90% full by the same date in subsequent years. On an aggregate level, 2022's goal was reached by end-August 2022, exceeding the targets, although some countries still struggled to adhere to their obligations. For 2023 August, storage levels in Europe have consistently stayed close to, or at, record levels, exceeding the storage objectives set by the EU.

Considering the recent advancements in gas storage levels, Europe is expected to encounter a winter season that is more robust and resilient than the previous year. Yet, it is important to acknowledge that there are several potential factors, such as temperatures and further supply events, that could significantly upset the balance.

Figure 32: Daily European gas storage volumes and range in underground storage, excluding Ukraine

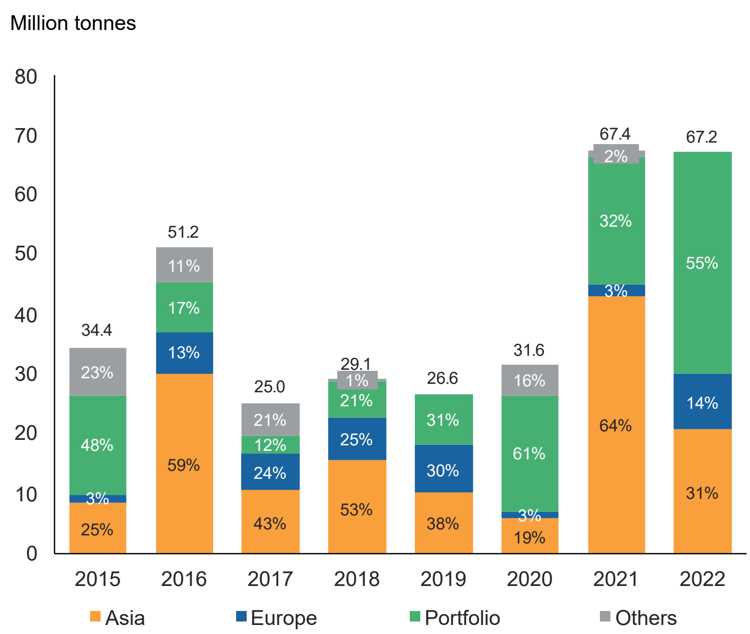


Source: Rystad Energy

Global LNG contracts mainly focused on longevity

Historically, Asia has been the largest purchaser of LNG volumes, followed by Europe, with the Asian region actively contracting even larger and longer-term volumes over the last decade (see Figure 34 for contract durations). However, following the natural gas supply crunch in 2021, newly signed contracts for LNG volumes spiked during 2021 and 2022, mainly aimed at bolstering energy security in the face of growing uncertainty. This trend was primarily caused by strategic decisions taken around energy supply in Asia and Europe. While Asia continued to secure contracted volumes, Europe mainly focused on obtaining spot volumes through portfolio contracts. It is noteworthy that volumes stemming from portfolio contracts will eventually end up in the spot market, available not only to Europe but also Asia and other regions opting to import LNG. The strategic divergence between Asia and Europe ultimately results in different levels of predictability and reliability for their respective LNG supplies, with Asia's strategy positioning it

Figure 33: LNG contracted volumes, split by region and portfolio



Source: Rystad Energy; IGU LNG Report

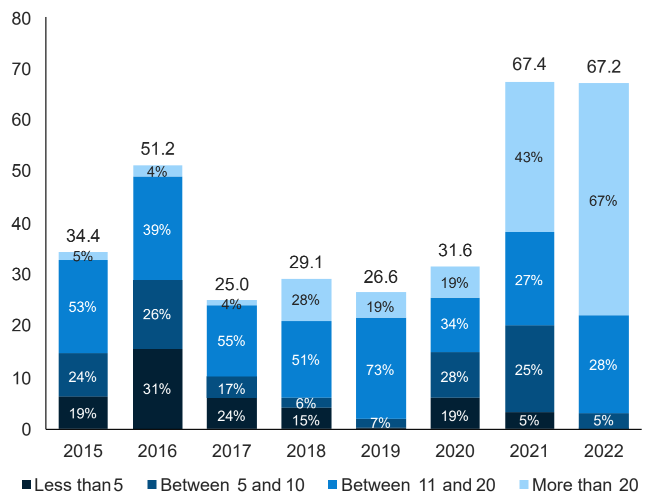
for more reliable LNG supply than Europe. While the total contracted volume of LNG has surged in recent years, a large share of this comes from an uptick in the proportion of long-term agreements. This shift in focus continued in 2022, with an even higher percentage of new contracts being long-term in nature. As much as 67% of all new volume signed in 2022 was for over 20 years in length, an increase of 24 percentage points from 2021 which was already at record-high levels.

Table 2: LNG contract types

LNG transaction types	Description
Spot	• Purchase or sales of LNG are made at prices in real time • Most spot market transactions are settled in a few days
Portfolio contracts	• By players who hold LNG supplies from different regions, and have shipping, storage, and regasification assets • Contracts can be either short -term or long -term • Prices can be on a spot or term contract basis
Long-term contracts	• Price is often linked to natural gas and oil benchmark prices • Contract period is typically more than 15 years

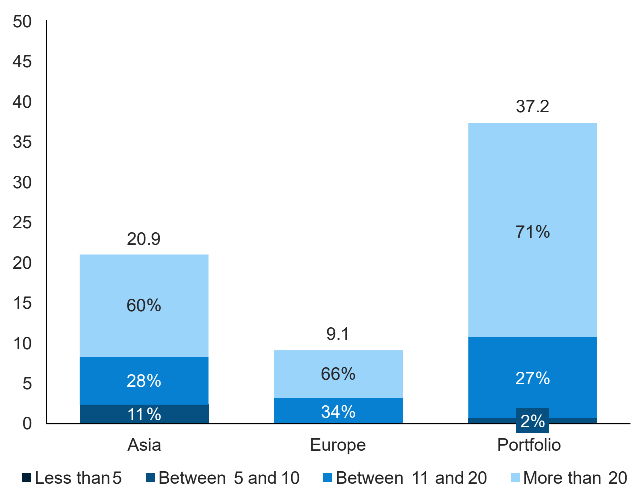
Source: Rystad Energy

Figure 34: New LNG contracted volumes, split by duration



Source: Rystad Energy; IGU LNG Report

Figure 35: New LNG contracted volume durations (2022), split by duration



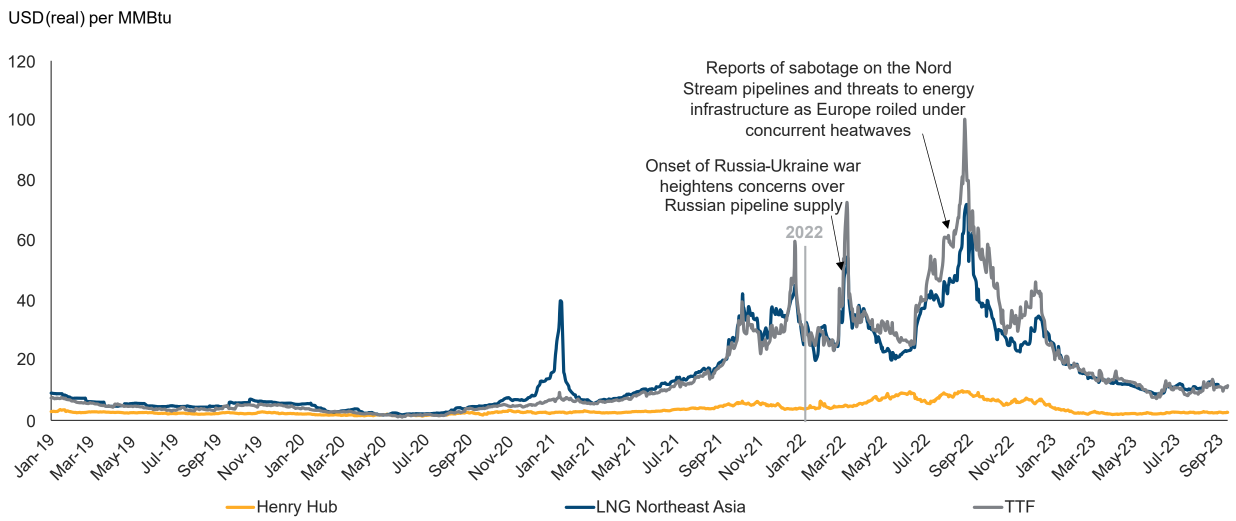
Source: Rystad Energy; IGU LNG Report

Pricing

In general, 2022 stands out as a year of unparalleled turbulence for global gas markets, coming on the back of already elevated 2021 prices amidst a tight global market. The year began with an air of uncertainty over Russian pipeline supplies to Europe. From there, gas prices experienced their first record spike after the Russia war with Ukraine began in late-February 2022, and triggered a cascade of geopolitical and energy sector responses. Thereafter, gas prices embarked on a streak of re-cord-breaking surges. The peak of this chaotic period came in late-August 2022, when natural gas prices reached an all-time high as the Netherlands-based Title Transfer Facility (TTF) closed at around 90 USD/MMBtu and Asian prices surged past 60 USD/MMBtu. Amidst the hike in prices, several European Union member states called for a price cap on natural gas prices within the EU.

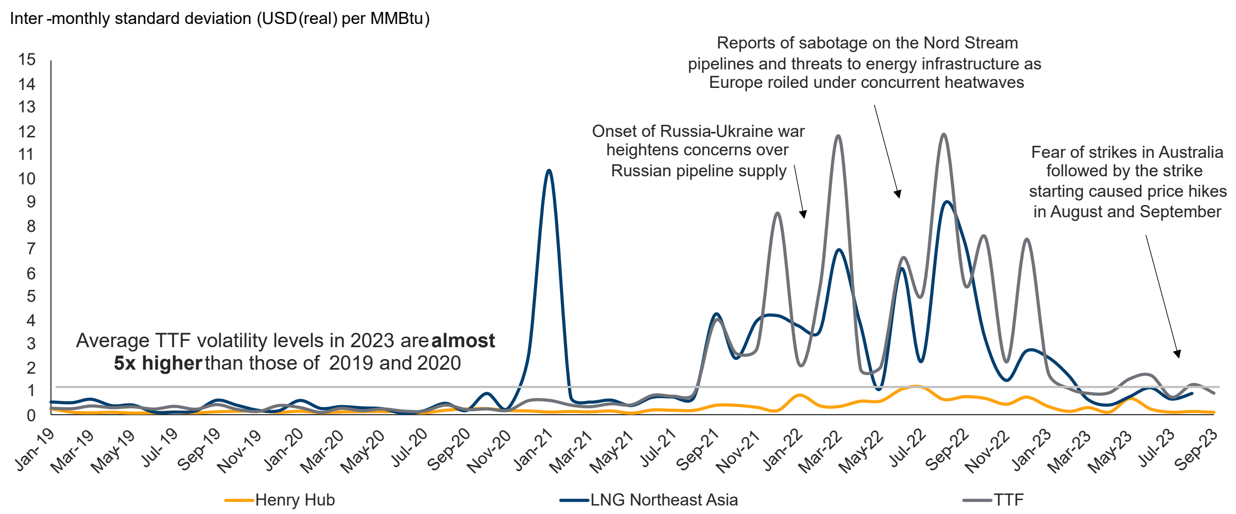
In response, the European Council reached a consensus in December 2022, setting a price limit at 180 EUR per megawatt-hour (equalling about 55 USD/MMBtu). Across Asia in 2022, a combination of factors including fluctuating demand due to Covid-19-related lockdowns in China, price-induced demand contraction in the South and South-East, and fuel-switching led to Asian gas prices consistently trading below TTF.

Figure 36: International natural gas prices



Source: Rystad Energy; Argus (LNG Northeast Asia)

Figure 37: International natural gas price volatility



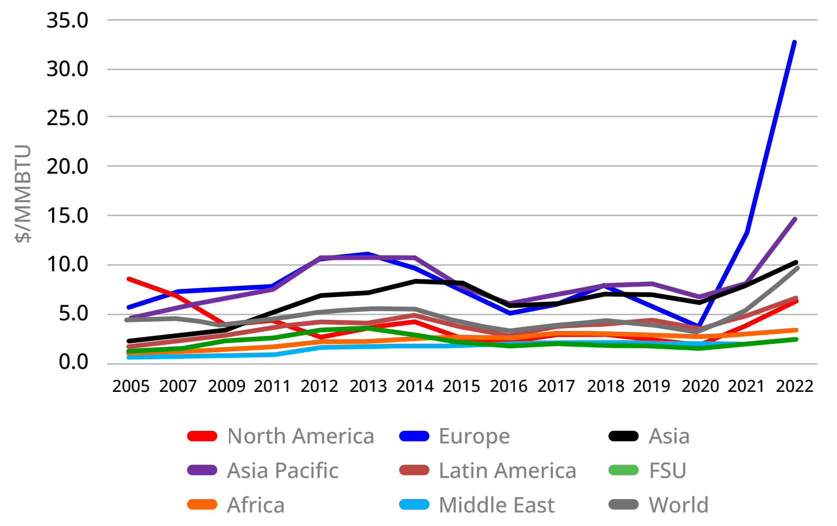
Source: Rystad Energy; Argus (LNG Northeast Asia)

So far in 2023 (September), natural gas prices have predominantly been on a downward trend, where factors such as demand contraction and a relatively warm beginning to the northern autumn have led to price reductions. On the supply side, Freeport LNG in the United States returned to production in February 2023 after being out of service due to a fire in June 2022, restoring a significant share of liquefaction capacity and putting downward pressure on European and Asian gas prices. At the same time, price reductions in early 2023 triggered some spot buying activity from price-sensitive markets in Asia. So far in 2023, the prices remain much lower and less volatile in than in 2022. Despite the improvements seen from 2022, gas prices and price volatility in 2023 remains significantly higher than in pre-crisis years (as depicted in figures 36 and 37). As of September 2023, the gas prices show extreme sensitivity to any change in market conditions, real or expected, mainly due to the exceedingly tight market balances with no major new supply additions to come for the next two years. This vulnerability was clearly demonstrated by the market's price response to the labour strikes at Chevron's facilities in Australia in September 2023, which have now been resolved. Going forward, any notable shift on either demand or the supply side, like a harsh winter or a supply shortage bound for Europe or Asia, could disrupt the fragile equilibrium once again.

Turbulent LNG markets caused local gas prices to spike

For importing regions, the gas prices in local markets are determined by the supply of gas at the market entry point, where these entry point prices in turn are dependent on localised factors, including infrastructure capacity. These regions are typically priced against global LNG prices, as they compete for the same scarce LNG volumes. Throughout 2022 and extending into 2023, the massive demand for LNG imports to Europe led to a bidding war between Europe and Asia for these scarce LNG volumes, leading to local gas prices soaring in both regions. This was in turn reflected in Asian spot and TTF pricing developments .

Figure 38: Wholesale price levels 2005 to 2022 by region



Source: IGU

As Europe's dependence on traded-market LNG has surged, while its previous cushion of long-term contracted Russian pipeline gas has largely disappeared, there is a greater interdependence between Europe's market and the other regions. As 2022 demonstrated, this dependence works both ways in an environment of tight global supply where greater demand competes for limited resources. The impact of the September 2023 strikes in Australian on European gas future prices serves as a compelling illustration of the development of these dynamics, where disruptions that would previously have had limited impact on European markets now caused the price to soar by about 18% and 13% following the strike warning and the commencement of the strike, respectively.

Henry Hub's correlation with other LNG markets has, and could continue to, strengthen

Markets that rely primarily on domestic production to meet local demand have historically developed almost independently of other markets, with prices set by local forces, as can be seen in most of the Middle East and the United States. In 2022, and continuing into 2023, this dynamic was mirrored in the developments of the Henry Hub which averaged a price about five and six times lower than Asian spot and TTF respectively. Yet, in both 2022 and up to September 2023, Henry Hub's correlation with other LNG markets exhibited a notable increase compared to previous periods, as it followed the price increases more closely. While LNG exports contributed to these developments, increased local gas demand in the United States, coupled with constraints in the pipeline infrastructure to meet this demand, also played a significant role. Thus, the increased correlation was not necessarily a causal effect of exports alone.

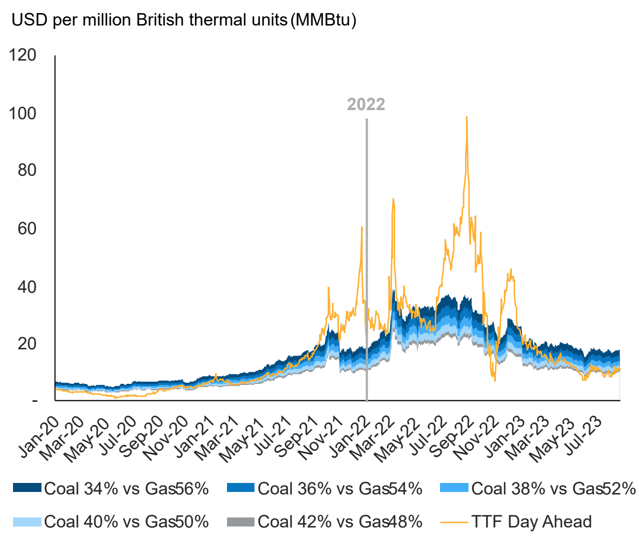
Through a thorough examination, the IGU's Wholesale Gas Price Survey for 2023 revealed a notable surge in the coefficient of variation of prices[5] on a global scale. In 2022, it soared to nearly 100%, marking a substantial increase from around 60% in the previous year. In the foreseeable future, Europe expanding its re-gasification capacity and engaging in more spot volume trading, coupled with the United States expanding their pipeline network, especially from the Permian basin, and increasing liquefaction capacity, could set the scene for further price convergence. However, prevailing uncertainties persist regarding various factors, including European gas demand and

[5] *The coefficient of variation of prices of a dataset in a certain year is determined by the standard deviation divided by the mean value of these prices. The amount of absolute price variation (standard deviation) is thus measured relative to the average price in a certain year. A low coefficient of variation indicates a higher level of price convergence and vice-versa.*

American associated shale gas exports. Nevertheless, efficient LNG markets going forward should entail TTF prices trading at the HH price with additional shipping, liquefaction, and premiums, and as such being more closely correlated with the HH price.

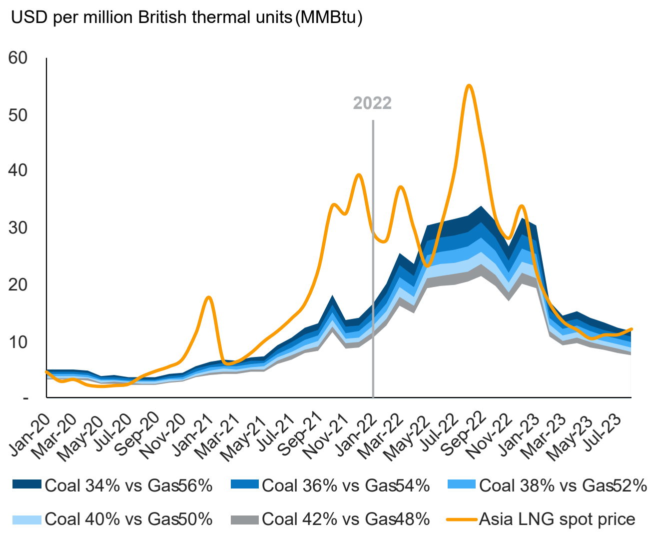
High gas prices drove gas-to-coal switching

Figure 39: Daily European gas prices (TTF) vs coal-switching price in the Netherlands



Source: Rystad Energy

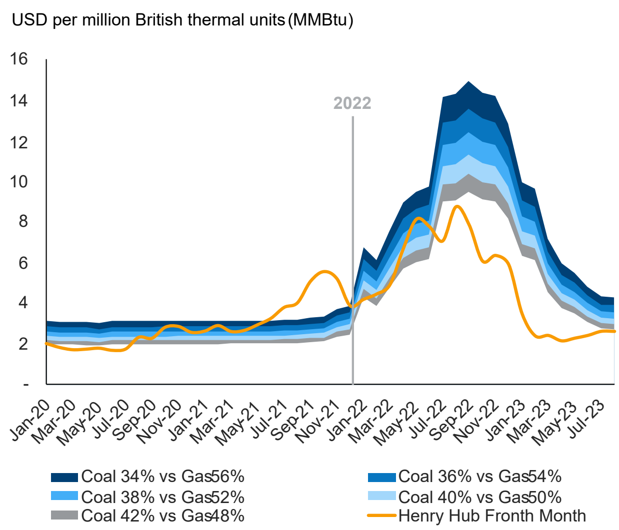
Figure 40: Monthly average LNG prices vs coal-switching price in Japan



Source: Rystad Energy

In figures 39 to 41, Coal 42% vs Gas 48% (grey shaded area) signifies the lower range of the coal-to-gas switching band between high-efficiency coal (42%) and low-efficiency gas (48%), while Coal 34% vs Gas 56% (in dark blue) shows the higher range of the coal-to-gas switching band between low-efficiency coal (34%) and high-efficiency gas (56%). When the yellow line crosses the grey area it is cheaper to turn on the most efficient coal-fired power plants at the expense of the least efficient gas-fired, similarly, if the line is above all of the bands even the most efficient gas-fired power plants are more expensive than the least efficient coal-fired ones.

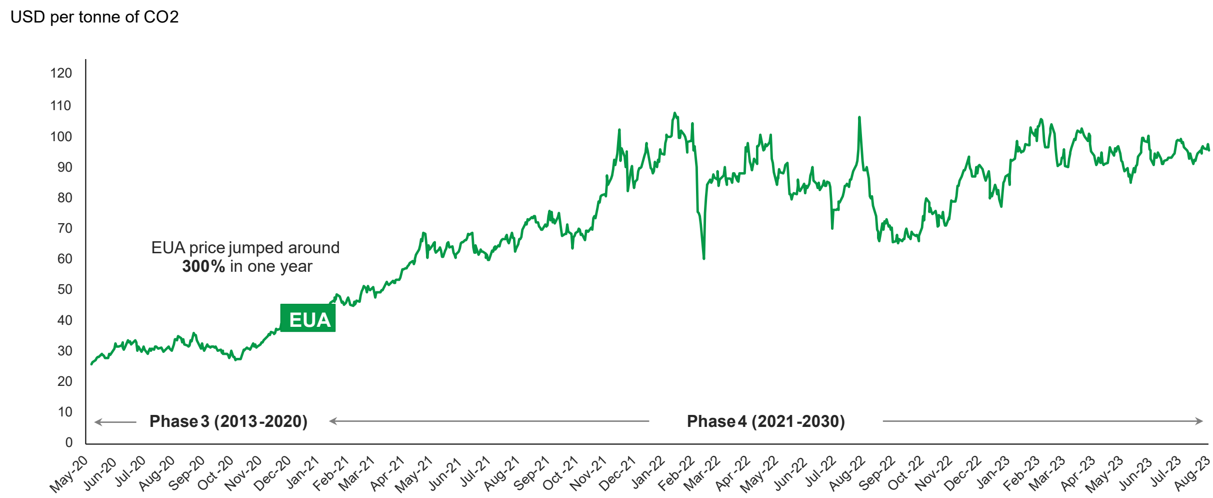
Figure 41: Monthly average Henry Hub gas price vs coal-switching price in the United States



Source: Rystad Energy

If gas prices reach high levels, the potential for switching to alternative fuels comes into play. Typical fuels used in such cases include coal and fuel oil, for which numerous countries have pre-existing infrastructure that has lain dormant due to environmental concerns and the growing integration of carbon pricing. The choice to switch from gas to coal is commonly evaluated using coal switching price bands. Broadly speaking, when the gas price exceeds the band, it becomes economically viable to switch to coal. As illustrated in figures 39 to 41, in

Figure 42: European Emission Allowance (EUA) price – EU Emission Trading System (EU ETS)



Source: Rystad Energy

2021 the gas price surpassed this band at all trading points. This trend intensified in 2022 for both Asian spot and TTF, driven by the soaring gas prices. In 2022 switching was economically attractive and as such, Europe and Asia saw a coal-fired power generation increase of 1.3% and 2.6% respectively in 2022 compared with 2021. Coal prices rose with increased demand with higher gas to coal switching activity. Leading up to September 2023, the economic justification for coal switching in Asia and Europa has weakened as gas prices have decreased, prompting numerous power generation companies to revert to using natural gas.

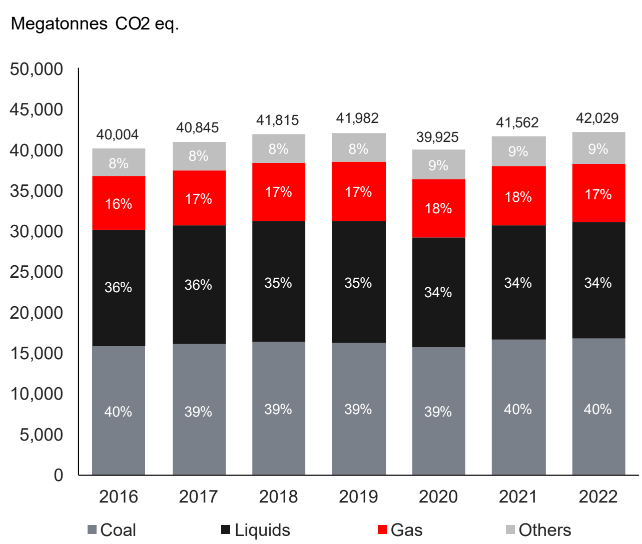
European carbon prices are incorporated in the European coal-switching price bands, as coal is a higher emitter than gas. Consequently, a high carbon price makes gas and other low emitters preferable to coal. The beginning of 2022 saw carbon prices continue to rise from the previous year, favouring coal-to-gas switching. Subsequently, many regions switched from using gas to using coal, driven both by economic factors and constraints such as limited import capabilities. A direct consequence of the increased adoption of gas-to-coal switching was a rebound in carbon prices, as energy and coal-related supply chains were required to buy more carbon allowances.

Emissions

Despite significant reductions in energy use in many regions in response to the global energy crisis, global emissions from energy still reached a record-breaking level in 2022 of almost 42 gigatonnes. 2022 saw the introduction of new energy transition acceleration policies, including the Inflation Reduction Act (IRA) in the United States and REPowerEU in Europe.

In 2022, total global energy-related CO2 emissions grew by about 1.1%, continuing the upward trajectory. Emissions from natural gas consumption saw a minor decline, partly attributed to price spikes which incentivised the adoption of alternative energy sources. As a result of gas-to-coal switching, total emissions from coal increased in 2022 albeit decreasing in portion of total emission mix, reaching an

Figure 43: Global energy emissions, split by energy source



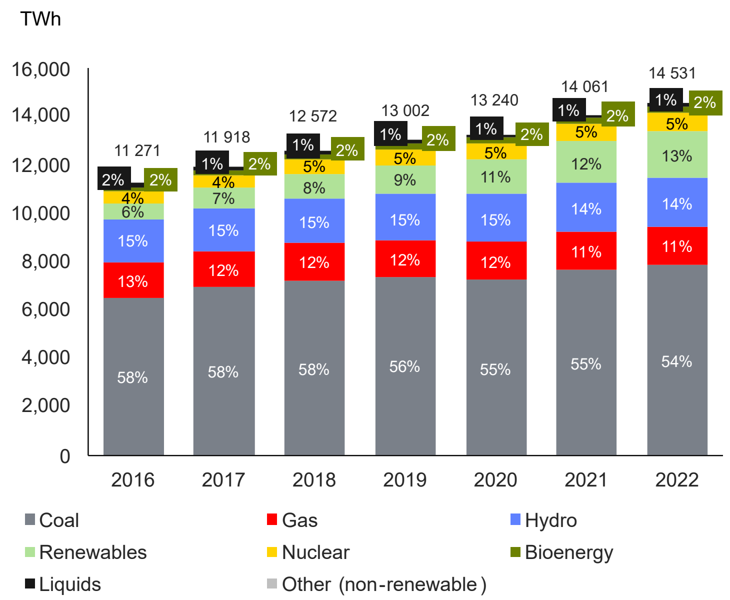
Source: Rystad Energy

all-time high of about 16,752 mega-tonnes of CO2 equivalents. The rise in total coal usage despite worldwide initiatives to diminish its dependency on coal, as it is the main driver of global emissions contributing to climate change highlights that the fuel remains a hard to replace energy source. Coal has been responsible for roughly 40% of the annual energy-related emissions consistently over the last years, as seen in Figure 43.

Asian power production continues strong dependence on coal

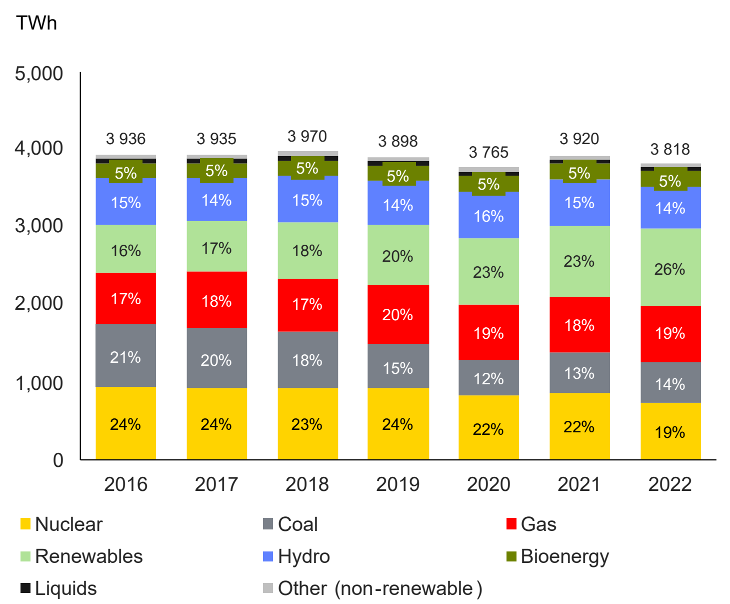
Asia has experienced a substantial surge in power demand coupled with its robust economic growth over the past decade, and this was primarily met by coal as an energy source. From 2021 to 2022, there was a marginal 0.9% reduction in the use of gas for power generation, while coal saw a notable 2.6% increase. These developments were mainly driven by China, accounting for a about 68.7% of the increase in coal consumption and about 37.5% of the reduction in gas. Looking ahead to 2023, both China and India are sustaining the upward trajectory of coal utilisation for power generation. In July 2023, these countries exhibited year-on-year growth rates in coal-based power production, with China experiencing a 7.9% increase and India recording an even more substantial 9.3% growth.

Figure 44: Asia's power mix (2016-2022), split by energy source



Source: Rystad Energy

Figure 45: Europe's power mix (2016-2022), split by energy source



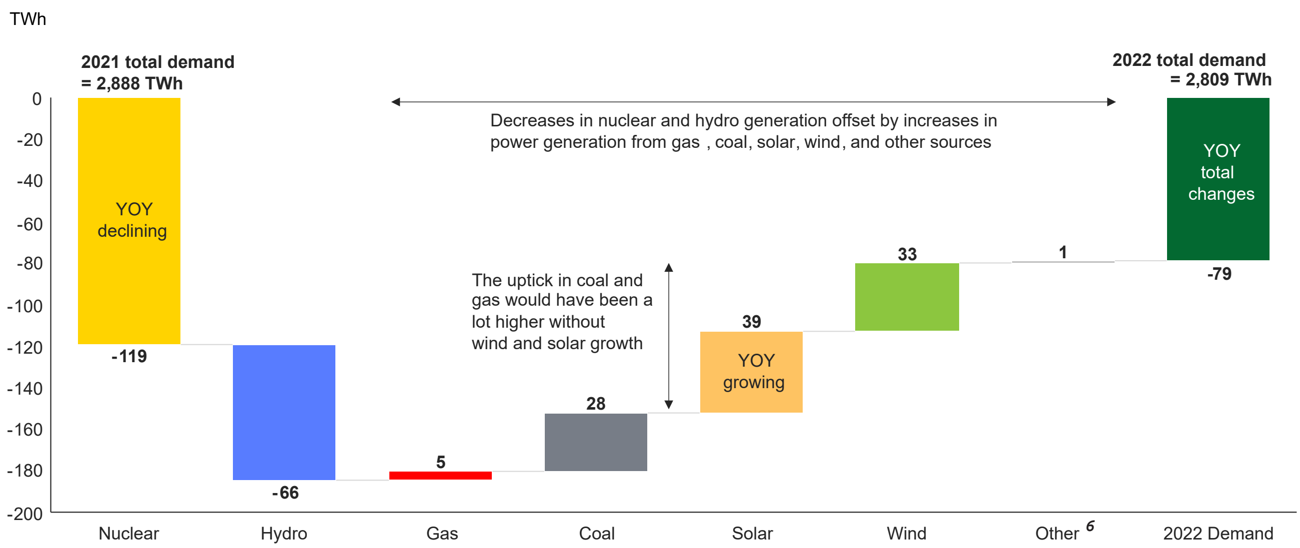
Source: Rystad Energy

Coal's position in the European power mix continues reversed trend

Until 2021, coal-fired electricity generation had been steadily declining in Europe since 2012, in large part thanks to switching to natural gas and renewables.

However, in 2021 coal gained positive momentum again due to growing affordability concerns surrounding gas, coupled with availability concerns of renewable energy. In 2022, the shortage of gas supply in Europe created more positive momentum for coal over gas. Additionally, according to the IEA, EU-countries faced a

Figure 46: Changes to power consumption in EU countries (2021-2022), by generating source



Source: Ember monthly electricity data

loss of 119 TWh of nuclear generation due to nuclear outages in France and 66 TWh of hydro generation stemming from the extreme drought across Europe, which was fulfilled mainly by coal, solar and wind. Consequently, European coal consumption in power production increased in 2022 despite decreases in overall power consumption throughout the year. Germany, due to limited abilities to reroute gas imports (as discussed in the Trade Flows sub-chapter), was in the forefront of this development. Power sector emissions in the EU countries increased in 2022 by about 3.9% from 2021, to 26 million tonnes CO2 equivalents. Yet, the reversal of the long-term trend on cutting down on coal usage is expected to be temporary as EU countries returning to implementing their pledges to phase out coal in the future – Netherlands in 2029, and Germany and Romania in 2030.

The direct effect of gas-to-coal switching on power-related emissions

Table 3 illustrates the different carbon intensities of coal, liquids, and gas. Natural gas has an emissions profile that is about 50% lower than coal and about 20% lower than liquids, making switching from coal and liquids to natural gas in power generation a way to significantly reduce emissions.

There are multiple pathways to drive down the emissions in natural gas further. One primary method involves implementing carbon capture technologies (CCS and CCUS), which are pivotal for the success of the energy transition at large. Another pathway is reducing the carbon content of the fuel through the deployment of green or low carbon gas technologies. This includes the utilisation of renewable natural gas or biomethane, hydrogen, and other potential emerging forms of low-emission gaseous fuels. Further exploration of these strategies can be found in Chapter 2.

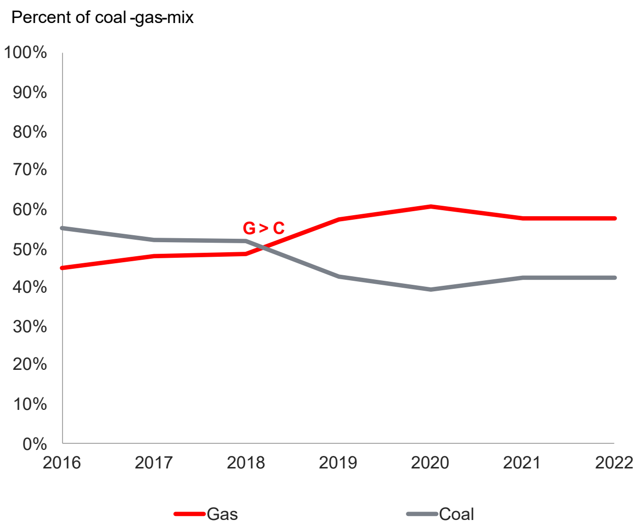
Table 3: Emissions in power applications, by energy source

Energy source	Direct emission factor (Mt CO 2-eq/ TWh)
Coal	0.8
Liquids	0.5
Gas	0.4

Source: IPCC AR6

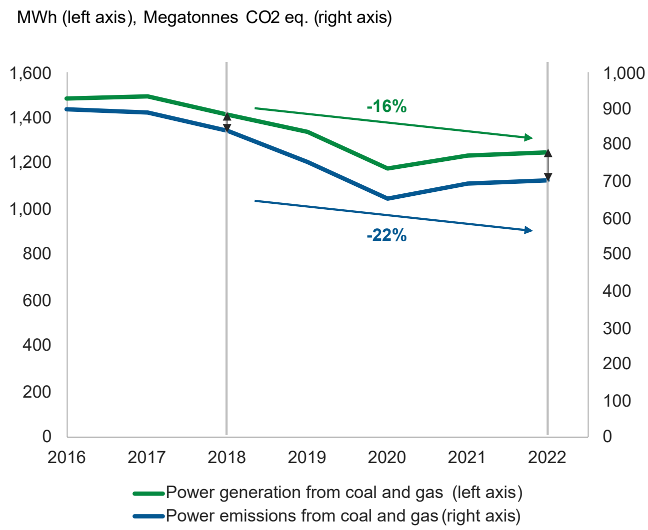
[6] *Includes bioenergy, other renewables, other fossil fuels and net imports.*

Figure 47: Coal and gas in the European power mix



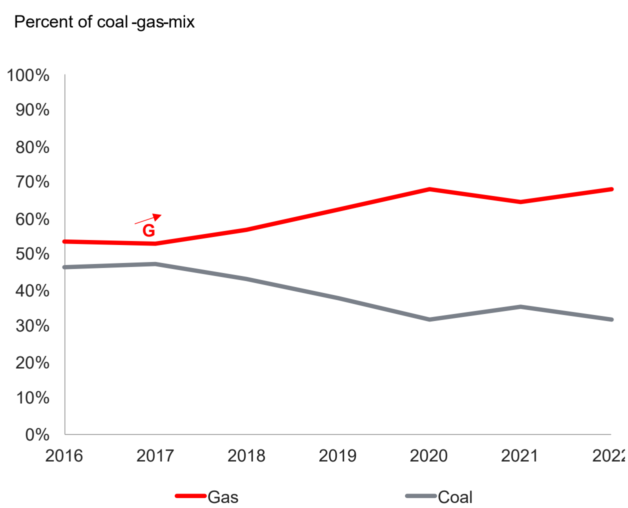
Source: Rystad Energy

Figure 48: Power generation and emissions from coal and gas in Europe



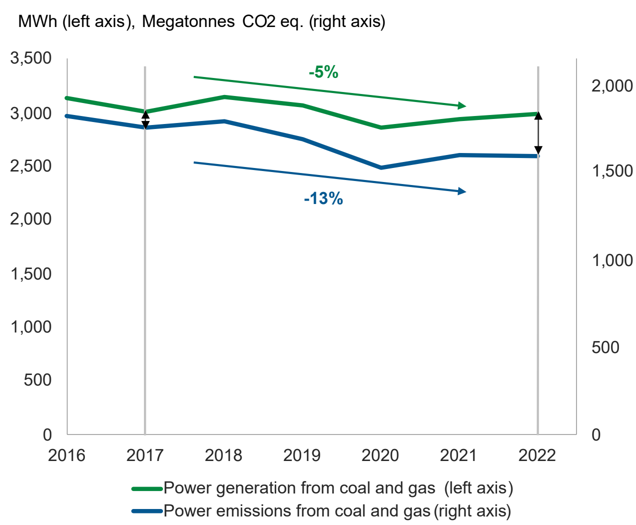
Source: Rystad Energy

Figure 49: Coal and gas in the North American power mix



Source: Rystad Energy

Figure 50: Power generation and emissions from coal and gas in North America



Source: Rystad Energy

Figures 47 and 48 pertain to Europe, with Figure 47 illustrating the coal-gas mix for power generation and Figure 48 showing the power and related emission generated from coal and gas. Figures 49 and 50 focus on North America and showcase the same contents. As shown in Figure 49 and 40, both Europe and North America have reduced power generation from coal and gas, but related emissions have decreased more substantially than power production. This is due to a shift in their coal-gas mix, as both regions increasingly favour gas over coal in the power mix, as evident in figures 48 and 50. The effect of having higher proportion of gas in power mix on emission reduction while maintaining stable power generation is particularly noticeable in North America between 2021 and 2022. In this period, North America increased its fossil-based power production while reducing related emissions. This can be attributed to a higher utilisation of gas in power generation, driven by Henry Hub consistently remaining at or below the lower end of the switching band throughout 2023, making gas a more economical option than coal.

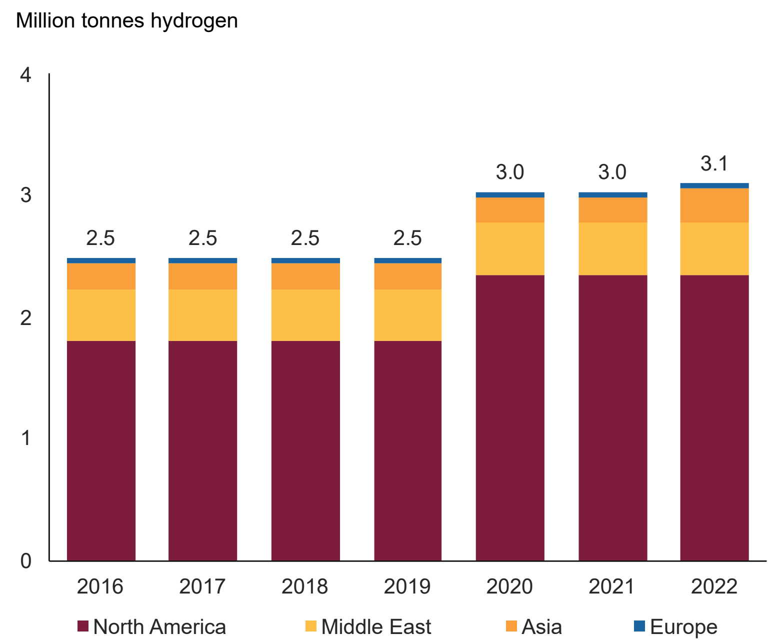
Development trends of low carbon gases

Low carbon gases are a critical component of decarbonising the consumption of gas, and a necessary building block in a successful energy transition, which will require significant scaling of low carbon gaseous energy. 2022 has seen an increase in capacity and a higher level of project announcements, sending a positive sign about this market segment. However, the speed and scale are still far behind what is needed for the energy transition and for the world to develop in accordance with lower global warming scenarios.

Blue hydrogen saw limited growth considering spiking natural gas prices

Currently, most of the world's hydrogen is produced using natural gas, and blue hydrogen, which is decarbonised natural gas based, has a significantly larger share of the nascent low carbon hydrogen market compared to green hydrogen. This is largely due to its favourable economics and an already established supply chain. The competitiveness of blue hydrogen[7] faced challenges amid the elevated natural gas prices in 2022. However, it remains an attractive option to produce low carbon hydrogen and is cost-competitive compared to green hydrogen, as was the case even in the high-priced natural gas environment in 2022. Normalising natural gas prices in 2023 further strengthen its business case. Blue hydrogen projects financed in 2023 are on average 59% cheaper to produce than green hydrogen according to a 2023 analysis done by Bloomberg NEF. This has driven European corporations to include blue hydrogen in their hydrogen strategies, where for instance RWE announced plans to offtake blue hydrogen from Equinor in January 2023. Significant greenfield blue hydrogen projects are also emerging in other parts of the world, seen by projects like Baytown CCS and H2OK in the US, H2Perth in Australia, and Hydrogen to Humber Saltend in the United Kingdom. During the first half of 2023, a total of around 1.4 MTPA of nameplate capacity for blue hydrogen projects has been announced, which would result in an increase of 45% of total nameplate capacity from 2022 levels if realised, indicating strong momentum in the segment.

Figure 51: Global blue hydrogen nameplate capacity, split by region



Source: Rystad Energy

As of September 2023, blue hydrogen remains small but with significant potential, both through retrofitting of grey hydrogen facilities and greenfield projects. Most of the blue hydrogen nameplate capacity is concentrated in the United States and Canada, with 49.7% and 24.6% of total annual blue hydrogen production, respectively. For a

[7] *Blue hydrogen is produced by splitting natural gas into hydrogen and CO2, where the CO2 is captured and stored through CCUS.*

deeper exploration of expected future low carbon gas and CCS developments, see Chapter 2 and 3.

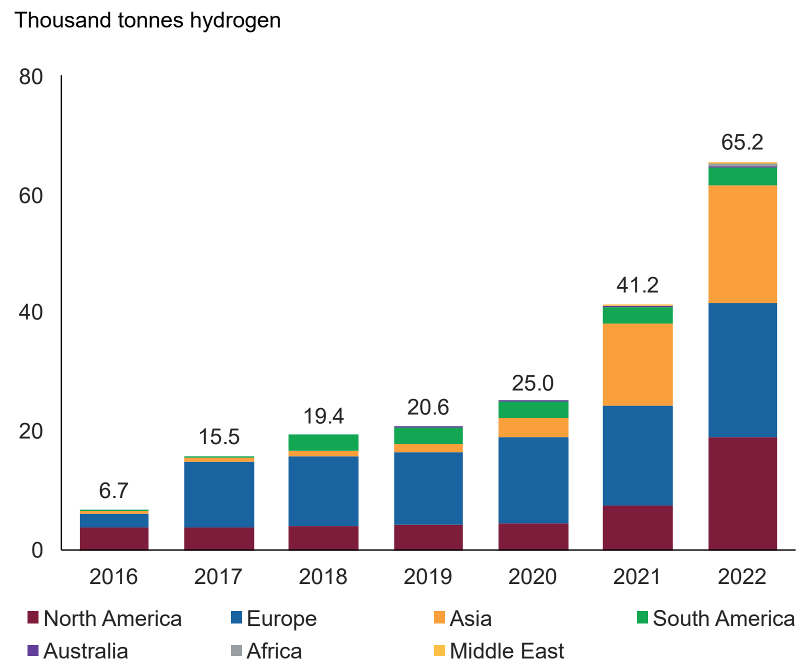
In the United States, the Inflation Reduction Act (IRA) offers carbon emissions tax credits which improves the competitiveness of all hydrogen production methods, although green hydrogen receives the highest share of incentive. In contrast to the United States, Asian markets like South Korea and Japan showed no strong preference for production method of low carbon hydrogen. In 2022, the Chinese project Sinopec Qilu Petrochemical CCS was the sole additional pure blue hydrogen facility to start operations, contributing an additional 70 kilo-tonnes hydrogen nameplate capacity.

Ammonia is a hydrogen carrier that can be used for transportation and storage of hydrogen. It is produced through synthesis combining hydrogen and nitrogen, can be shipped as liquid or solid, and then cracked back to hydrogen at the consumer. Blue ammonia as a carrier for blue hydrogen has also gained traction in the first half of 2023, with Saudi Arabia driving the project developments this year. The Saudi Arabian mining company Ma'aden received certification for production of blue ammonia in 2022, and the company had its first shipment of 25 kilo-tonnes of blue ammonia to South Korea in December the same year. During the first half of 2023, the company has expanded both production and export routes, and is now exporting 138 kilo-tonnes to countries like China, South Korea, and Japan. In 2023, Saudi Arabian company SABIC in conjunction with Saudi Aramco started the SABIC-Aramco blue ammonia project, which in April 2023 shipped the first independently certified low carbon ammonia for use in power generation in Japan.

The green hydrogen sector is put in the centre of new legislations

The pipeline of green hydrogen[8] projects has steadily expanded in recent years, with growth seen in standalone hydrogen projects and those that use the generated hydrogen to make other end products, such as green ammonia. Green hydrogen current nameplate capacity remains relatively small-scale, accounting for about 2.1% of decarbonised hydrogen capacity in 2022. Nonetheless, its growth is substantial, with annual nameplate capacity having doubled each year since 2020. In 2022, more than 20 kilo-tonnes of new nameplate capacity were added globally. From January to September 2023, roughly 30 kilo-tonnes of new capacity have been added, all from assets in China, with the Kuqa Green Hydrogen Project accounting for 20 kilo-tonnes of this increase.

Figure 52: Global green hydrogen nameplate capacity, split by region



Source: Rystad Energy

As with the case for blue ammonia, also green ammonia has gained traction recently for applications like hydrogen carriage, industrial feedstock, fuel substitute and for direct use in power generation. In 2022, green ammonia's nameplate capacity grew by around 19 kilo-tonnes from nearly negligible level in earlier years, contributed by Fertiberia's ammonia plant in Spain. In the second quarter of 2023, the green ammonia project NEOM in Saudi Arabia reached FID. The FID is currently

[8] Green hydrogen is produced through electrolysis of water.

the biggest for green hydrogen in the world, marking a milestone for the hydrogen sector as the first gigawatt-scale green hydrogen project to reach this stage. Upon completion in 2026, the 8.4 billion USD project is expected to produce 1.2 MTPA of green ammonia.

While the capacity increments were modest, 2022 saw the implementation of several policies that significantly bolstered the economic feasibility of green hydrogen. In the United States, the IRA was introduced with a series of tax credits. While benefiting all types of hydrogen, the policy offers additional tax credits for hydrogen from renewables or nuclear, potentially making green hydrogen cheaper than blue or grey versions in the short term.

The Act also introduces a 30% investment tax credit for zero-emission projects, with the possibility of higher incentives based on local conditions. In Europe, the REPowerEU initiative signalled that green hydrogen is to be central in address the pressing climate crisis in the EU. As such, the plan envisions a drastically increased green hydrogen demand target compared to the previous Fit-for-55 scheme, boosting it from a projected 7 million tonnes to 20 million tonnes by 2030. The ambitious new demand target is expected to be met by 10 million tonnes of domestic hydrogen production, 6 million tonnes of imported hydrogen, and 4 million tonnes of green hydrogen from ammonia (and derivatives) imports. The EU hydrogen demand target of 20 million tonnes in 2030 compared to the current global green hydrogen nameplate capacity of 71 kilo-tonnes, results in a required increase in production capacity of about 280 times the current global levels. The plan would be backed up by the European Hydrogen Bank, providing financial incentives for green hydrogen producers. Details regarding this policy will be further discussed in Chapter 3.

Renewable natural gas or biomethane is small-scale but continues to see strong growth

Biomethane, also called renewable natural gas, provides a pathway for reducing emissions by substituting natural gas through capturing and utilising methane or biogas from decomposing waste, such as landfills or manure, which would otherwise be emitted into the atmosphere. It therefore provides high emission-reducing value by utilising methane emissions produced by other parts of the economy, including agriculture, to produce biomethane. After capture, the biogas is upgraded and purified to yield biomethane, which can directly substitute natural gas within the existing infrastructure, with no retrofitting required.

Globally, estimated biomethane nameplate capacity stood at around 7 Bcm in 2022, accounting for about 0.2% of global gas demand this year. However, the potential is much greater. Europe, in alignment with REPowerEU, aims to scale up annual biomethane production to 35 Bcm by 2030. North America has an additional biomethane production capacity of around 4 Bcm planned and under construction as of September 2023. Currently, the majority of production is concentrated in Europe, and the region saw the largest increase in installed capacity in 2022. Throughout the year, 144 new plants were added, increasing capacity by 0.2 Bcm. The United States has the largest biomethane production coming from one single country, and in 2022, 17 plants came onstream in the country, presenting 0.08 Bcm in additional volume. Regarding the choice of feedstock, Europe has experienced a noticeable trend towards the utilisation of agricultural residues, organic municipal waste, and sewage sludge, while North America has been mainly using organic municipal waste.

As of September 2023, Europe is still the most dominant region in the market, with more than 1200 operating plants representing almost 4 Bcm of yearly supply. As mentioned earlier, the region is expected to keep growing rapidly, as one of the actions proposed in REPowerEU is for Europe to scale up its annual biomethane production, diversifying away from Russian gas supplies. This would mean a required increase in European supply of almost 9 times compared to current own production levels. As of September 2023, the United States operates around 1000 plants producing about 4 Bcm yearly, growing at a slightly lower rate than Europe combined. Although still in its infancy, Asia continues to be the most promising growth supply market, with its abundant feedstock resources and increasing energy demands. In China, Air Liquide started operation of a biomethane facility in Huai'an City in 2022, which feeds the gas grid of the city. However, despite substantial investment from the central government, the market has not progressed as many anticipated.

The main value proposition for biomethane is its capability to displace traditional natural gas in various industrial applications and buildings, assuming that carbon taxes and the carbon market regulatory environment will be getting stricter in the future, increasing its competitiveness. However, a significant need for acceleration and scaling of supply is needed in order to meet targets, as illustrated through for instance the scaling need for European supply to meet 2030 targets set out in REPowerEU.

Synthetic methane has gained traction recently through several pilot projects

Synthetic methane or e-methane is another low carbon gas that is gaining attention, and as for biomethane, it is especially interesting as it could substitute natural gas in its applications without any need for change in infrastructure. E-methane is produced through using surplus supply of renewable energy to produce green hydrogen and combine this with either carbon from direct air capture (DAC) or carbon capture from industrial sites. The e-methane technology is still in early stages, and current projects consists of pilots to test viability and commerciality.

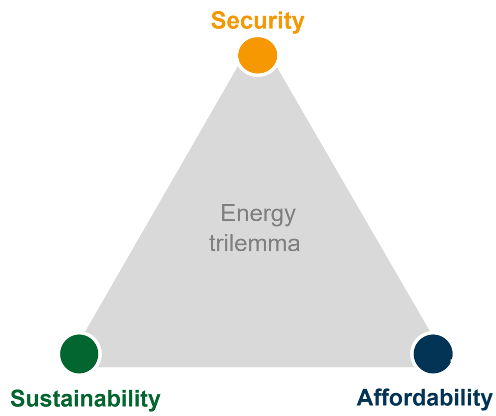
For instance, Japan aims to decarbonise their natural gas consumption through synthetic methane and has set targets for synthetic methane uptake in existing infrastructure of 1% by 2030 and 90% by 2050. Tokyo Gas, Japan's top city gas supplier, began a trial in June 2022, aimed at producing e-methane to replace 1% of the city gas volume by 2030. Furthermore, the company is conducting feasibility studies in Malaysia with Sumitomo and Petronas, and in North America and Australia with Mitsubishi. The Japanese gas company Osaka Gas has partnered with Marubeni and Peru LNG in Peru and Santos in Australia investigating the possibilities of producing e-methane that in turn can be transported to and distributed in Japan using existing LNG and natural gas infrastructure. In July 2022, as part of a pilot project, a partnership including Engie conducted the first injection of synthetic methane into the French gas distribution network. If breakthroughs to reduce costs can be achieved, e-methane could prove to be a major technology for decarbonising the natural gas supply. However, both scale, technology, and cost are challenges which e-methane will need to overcome for wider adoption to be achieved.

The historical evolution of energy policy priorities through the energy trilemma lens

The energy trilemma refers to the balance between the often-conflicting energy policy priorities: ensuring energy security, affordability, and sustainability. Security refers to having reliable, uninterrupted availability of energy whenever it is needed. In the short term, this could mean an energy system that delivers stable energy to consumers in the time and quantity it is needed. In the long term, it means providing energy supply that develops in trend with demand, in anticipation of any future demand changes or developments, and that is equipped to manage external risks. The latter is usually accomplished through energy system planning. Affordability means that energy is not only available, but also affordable for consumers. Sustainability requires that energy production and use minimise harm to the planet and future generations. Ideally, energy policy should aim for maintaining energy systems that balance the sides of the energy trilemma triangle, but how this balance can be accomplished varies due to factors like geography, finances, resource availability, geopolitics, and stakeholder interests.

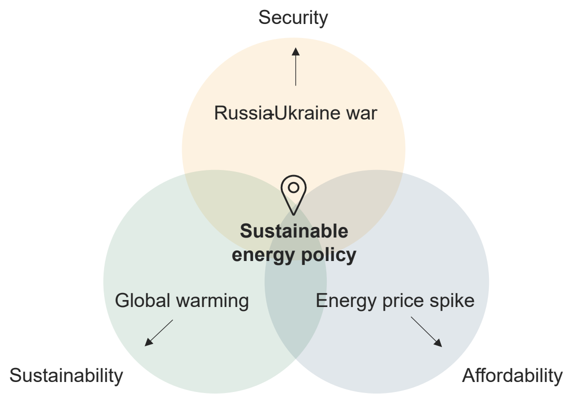
In the period following the 2014 oil price plunge triggered by the abundance of the United States shale production, the industry focus shifted to lowering energy production costs in a corrected market. At the same time, global policy emphasis generally shifted towards the energy transition, with decarbonisation gaining momentum after the signing of

Figure 53: The energy trilemma



Source: Rystad Energy

Figure 54: Effects of recent events



Source: Rystad Energy

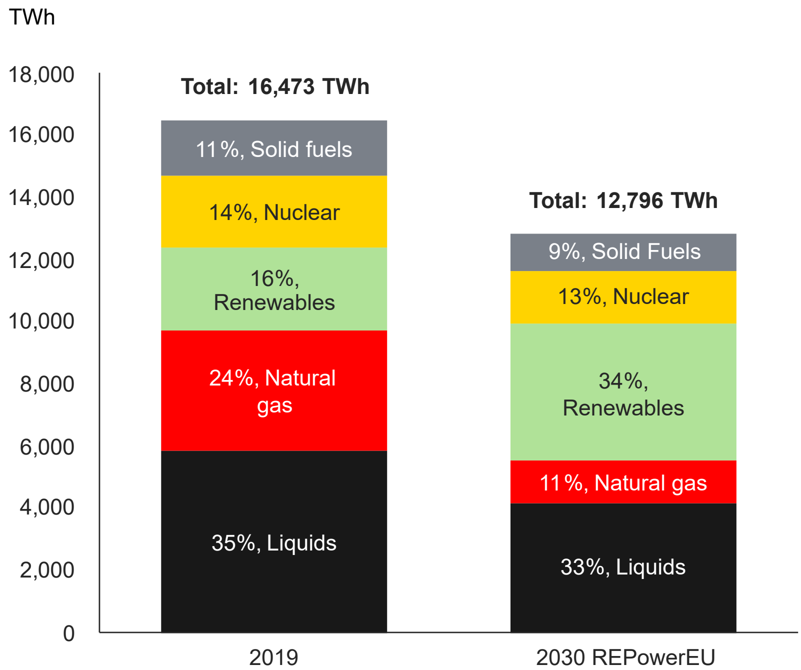
2015 Paris Agreement. However, as a general trend, many decarbonisation policies favoured measures on the side of energy supply, including restricting fossil fuels, over demand side management, and a lack of a global emissions pricing regime is a stark testament to that imbalance. This contributed to a growing disconnect between supply and demand evolution, with increasingly restricted supply starting to lag the unrestricted demand. The Covid-19 pandemic further worsened inflationary pressures, where strained global supply chains coupled with an unanticipated rapid post-lockdown surge in demand set off the rise in energy prices in 2021. In 2022, the Russia-Ukraine war took the supply tightness to a global crisis level, culminating in highest ever price spikes. This prompted nations to prioritise affordability, demonstrated by substantial growth in coal use, as key countries in Asia and Europe looked to more affordable alternatives. It was also seen in the strengthened energy consumer subsidies. For instance, the Indonesian government increased its energy subsidies by 39% in 2021 to IDR 243 trillion, and Europe has cumulatively spent close to 651 billion EUR on subsidies from 2021 September to 2023 June, according to a Bruegel dataset. Lastly, the Russia-Ukraine conflict underscores the need for dependable and diversified energy sources. This focus has driven nations to establish new energy partnerships and shift away from traditional suppliers in 2022 and demonstrated that when energy security and affordability are compromised, sustainability priorities are difficult to maintain.

Europe was forced to shift its focus from sustainability to security following the Russia-Ukraine conflict. This resulted in both a delay in coal phase-out and to an increase in spot LNG imports to secure short-term reliability. Further, the region is planning to electrify its energy system and expand renewable power generation to reinforce energy self-sufficiency and reduce dependency on imported fuel. Here, the former represents a conflict between sustainability and security, while the latter speaks to a synergy between the two dimensions. Currently, electricity represents about 23% of Europe's final energy consumption or around 2,478 TWh in the EU and going forward, it is forecasted by the European Commission to increase to about 33% or 2,687 TWh in 2030 in accordance with REPowerEU. The REPowerEU targets aim to achieve a 45% renewable share in final energy consumption mix by 2030 from the current level of about 16%. This coincides with its legislation to be fully independent of Russian gas by 2027.

To reach these targets, the EU has focused on increasing short-term gas supply from different suppliers like the United States and Norway, as well as exploring options in Egypt and Israel. The short-term approach hinges on achieving the EU 2030 target of reducing its total natural gas demand by 50% (even though this ambition still has to translate into an actual plan, since the latest ENTSOG scenarios of 2022 saw a reduction of only about 24% between 2021 and 2030). The policy strategy is focused on avoiding excess after 2030, and arguably prioritising the risk of stranded assets over the risk of undersupply if targets fall short of the 50% reduction in demand that the policy envisions. There are also plans to repurpose existing gas infrastructure for clean hydrogen in the future. Europe's future demand for natural gas is highly uncertain, given the aim to transition to low carbon gases and hesitance to sign long-term LNG contracts. However, the technical and economic feasibility of replacing 50% of natural gas demand within six years faces significant uncertainty. Primarily, the construction and modernisation of energy infrastructure is a time-consuming and capital-intensive endeavour. Even for projects that can complete constructions within a year, such as onshore wind farms and solar plants, the entire development process usually lasts four to eight years. Interconnection is one of the most critical and difficult phases in the development phase as the grids get increasingly congested. According to Lawrence Berkeley National Lab, the typical interconnection assessment duration from request to agreement in the United States was 35 months (just shy of three years) in 2022. Additionally, in order to triple the renewables capacity and double electrification of the energy system, it would be necessary to expand the electrical transmission and distribution grids. According to the IEA, the average lead time to construct an overhead transmission line is 10 years[11]. The EU's push for security and sustainability through renewables has also unveiled new concerns as critical materials and supply chains are highly concentrated geographically outside Europe, introducing similar security risks. To reduce security risks and bolster competitiveness, the EU introduced the Green Deal Industrial Plan to scale manufacturing and technology capabilities in its pursuit of net-zero. However, challenges such as prolonged lead times for local production, strained global supply chains, and soaring inflation are slowing decarbonisation efforts, making natural gas more likely to have continued presence in the European energy mix.

Across Asia, an evident shift towards security and affordability

Figure 55: Gross inland consumption by fuel in 2019[9] and in the REPowerEU scenario[10]



Source: European Commission; EuroStat; Primes

can be seen amid recent events, with several cases of gas to coal switching, and large energy subsidies focused on keeping energy affordable. In a bid to lower power generation costs and enhance security, Pakistan has announced that it will not build new gas-fired power plants in the coming years, and plan to quadruple its domestic coal-fired capacity to 10 GW in the coming years, from 2.3 GW. A shortage of gas, which accounts for 33% of the country's power output, plunged large areas into hours of darkness in 2022 during surges in global LNG prices after the Russia-Ukraine conflict made LNG unaffordable for Pakistan.

While Pakistan aims to reduce emissions by 50% against its 2015 baseline, this will be challenging with the upcoming plans of increasing coal capacity. Gas could provide a valuable lifeline for Pakistan in achieving security, affordability and sustainability if policies prioritise long term LNG purchase agreements over volatile spot market procurement. Large Asian economies like China are expanding their coal-fired generation, with 115 GW of approved coal capacity in 2022. Coal remains a key energy source, standing at 56.2% of the power mix in 2022, underpinning China's continued focus on affordable and reliable energy. However, coal-fired generation has led to poor air quality and severe pollution, prompting China's "Blue Sky" policy in 2017, which promotes coal to gas switching to improve urban air quality. The policy resulted in 25 million rural households switching away from coal for heating in the heavily

[9] Gross inland consumption refers to primary energy consumption in the EU, excluding international maritime bunkers. Primary energy consumption has no direct renewable targets by REPowerEU, while final energy consumption has targets of 45% by 2030.

[10] Units are converted using IEA's factor of 1 Mtoe = 277.8/23.88 TWh. Solid fuels refer to coal and coal derivatives, according to the European Commission.

[11] IEA, Average lead times to build new electricity grid assets in Europe and the United States, 2010-2021.

polluted regions by the end of 2020, of which 52% opted for gas, 38% for electricity, and the remaining for centralised heating and renewable sources. Gas is expected to continue playing an important role in China's energy mix, mainly in the form of a dispatchable and flexible source. In contrast, other Asian countries, including Singapore, South Korea, and Japan, have largely relied on energy imports, accounting for over 80% of their domestic energy consumption. These countries are major importers of coal and gas. Singapore, for instance, derived over 95% of its power from natural gas in 2022. Despite the reliance on imported coal and gas, these countries mitigate energy supply security risks through long-term LNG contracts and diversified sources, including countries like Australia, Indonesia, the United States, Colombia, and South Africa.

The shale revolution has taken the United States from being the world's most significant energy importer to a significant energy exporter from 2020. This has led the country to lean comfortably on its own energy production in recent years, despite the energy crunch that affected regions such as Europe and Asia since 2021. Albeit some reaction to a rise in domestic gas prices was observed in the United States as well. A clear shift in focus towards sustainability is evident through the enactment of the IRA. The IRA is expected to accelerate the energy transition, emphasising sustainability while preserving energy security by incentivising the scale-up of domestic value chains for green industries and technologies. The total bill of the IRA is anticipated to be nearly 800 billion USD, which brings into question the substantial financial commitments required for the transition to take place. Availability of capital amid a period of high inflationary pressure and cost escalation could threaten economic stability.

In developing regions such as Sub-Saharan Africa, poor energy access has underpinned the lack of energy security. According to the World Bank estimates, almost 800 million people lacked access to electricity globally in 2021, 600 million of them in Africa. This was following the cost-of-living crisis post Covid-19, which made electricity more expensive globally. Ensuring access to energy for impoverished regions is crucial for driving economic development and industrialisation. For this to take place, a massive additional energy demand will require a reliable and affordable energy source. Natural gas, with a progressively decarbonised gaseous energy mix in the coming years, can meet this need as gas can serve as a source of heat, power, and feedstock for critical industry - including fertiliser to provide food security and steel and cement to build roads and modern buildings. Though rural parts of Africa are exploring the option of building PV microgrids, that is by no means able to sustain heat and power-intensive industrial operations such as running a cement or fertiliser factory. On the sustainability front, there are still significant shares of industrial sectors around the world – especially Asia – that use coal for power and heat, where gas can serve the same purposes, and with lower emissions. Additionally, nearly a third of the world still relies on rudimentary cooking means such as coal, charcoal, and agricultural waste. Natural gas can help to accelerate the uptake of clean cooking, though this opts for the development of access infrastructure.

In conclusion, the energy trilemma highlights the challenges and shifts in policies to balance security, affordability, and sustainability in energy systems. Sustainability cannot be fully realised without the important pillars of security and affordability, and therefore all three need to be in balance. Natural gas and low carbon and renewable gases emerge as key energy sources in balancing the energy trilemma. Gas offers security that can bolster development and industrialisation in developing regions overcoming poverty. For areas that rely heavily on coal, gas provides similar security and affordability, enhancing sustainability by addressing air quality problems from coal use and reducing emissions, while making the grids more resilient to support the massive scale-up of renewables needed to reach transition goals. For developed regions looking to transition to renewables in a much shorter term, natural gas and low carbon and renewable gases serve as flexible and dispatchable source tackling intermittency, enhancing the reliability of grids, and fostering competitive industry decarbonisation. Furthermore, these gases can exploit existing infrastructure's adaptability, widening the range of options for the energy transition while helping to reduce its cost and ensuring futureproofing of needed investments towards strengthening of supply.

2 / 2030 and beyond – assessing the assumptions about future gas demand and outlooks

This chapter evaluates the future scenarios of natural gas demand leading to 2030 and beyond to 2050. Despite the remarkable uncertainty across existing energy transition scenarios, natural gas is expected to remain a significant participant in global energy markets in the coming decades. However, the level of future natural gas supply has been largely left to chance. The very large difference in levels of anticipated demand across different scenarios – including those that project such deep demand reductions that no new natural gas projects are needed anywhere in the world today – make it very challenging to plan investments, while the increasingly restrictive policy environment has raised the cost of these investments. Meanwhile, the current level of natural gas and LNG supply planned and expected to be available this decade is insufficient for a resilient balance in global gas markets, particularly with the rising global requirement for flexible and reliable energy amidst increasing extreme weather challenges to energy systems.

Furthermore, this chapter explores future natural gas demand scenarios and some of the uncertainty bands across different transition scenario assumptions to draw attention to the very real potential security of supply implications, particularly as 2030 draws closer. This chapter seeks to zoom in on what various scenarios mean for the gas industry and its stakeholders (governments, financial institutions, and energy companies), and more importantly, for consumers. The chapter utilises data and scenarios from the IEA World Energy Outlook (WEO) scenarios from 2022.

Highlights

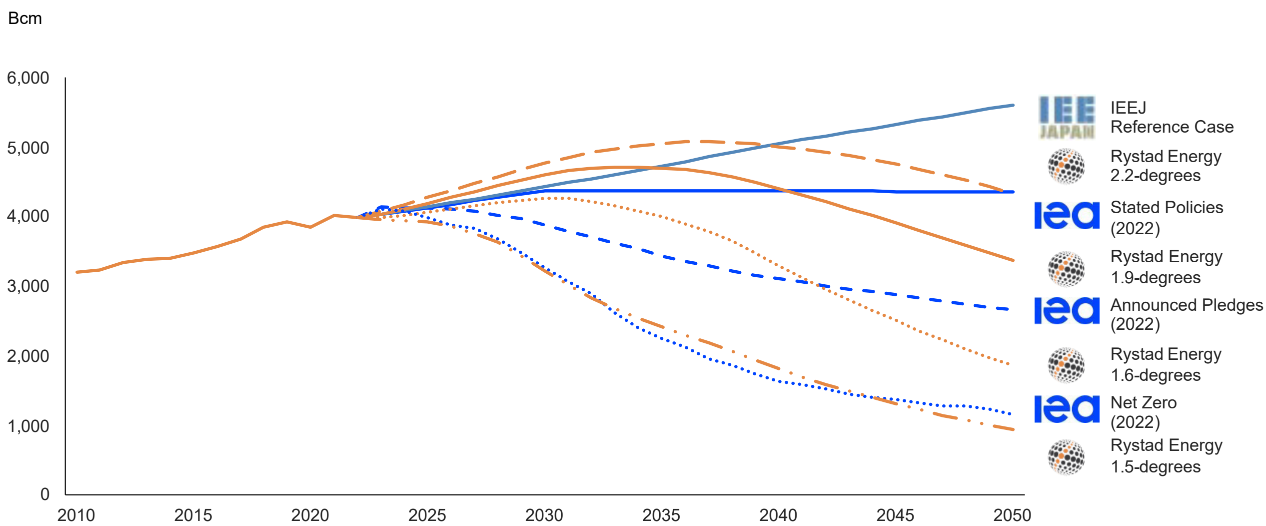
- **There is a need to develop additional gas resources, as many scenarios point towards substantial demand for natural gas towards 2030 and beyond.** Existing operational and FID-ed natural gas production is insufficient to meet most natural gas demand scenarios. Even in the deep decarbonisation scenarios like the 1.5-degree scenarios, around 100 billion USD of investments are needed in 2050, and low carbon gases play an important role in this scenario. When considering a less aggressive scenario, such as the Rystad Energy 1.9-degree scenario, the shortfall of future supply becomes more apparent, totalling over 1,000 Bcm. Globally, there are more than 200 Tcm of proven and probable natural gas resources, which is more than enough to cover high demand scenarios. However, it is essential for supply to be well planned and built out ahead of time to reduce the risk of impending global shortages, potentially threatening energy security, affordability, and sustainability, and to avoid an energy crisis, as seen in 2021 and 2022.

- **Deep decarbonisation scenarios call for massive renewable energy and electrification investments, posing capital availability challenges.** Balancing both investments while maintaining the pace of natural gas developments adds risk to both existing and future energy systems and calls for sound policies and incentive-based frameworks to facilitate sustainable development. Scarcity of capital may delay renewable energy adoption and divert capital away from essential gas developments that would cause major turbulence in energy markets in the current and coming decades. Hence, there is a need for integrated planning to ensure investment signals are not disconnected from reality, and sufficient capital is available for the investments.

- **Gas production of operational and underdevelopment projects is expected to fall short by 1,000 Bcm in 2050 from more than 4,000 Bcm in 2023 due to natural decline.** The output volumes are projected to decline to 3,134 Bcm in 2030, and further decline to 1,849 Bcm in 2040, followed by a decrease to just under 1,000 Bcm, falling to 974 Bcm in 2050.

Uncertainty in future gas demand scenarios

Figure 56: Global gas demand scenarios from various institutions[12]



Sources: IEA; IEE Japan; Rystad Energy

A wide range of perspectives have emerged outlining the potential trajectory of future natural gas demand and supply needs towards 2030 and beyond. In this section, we assess eight distinct scenarios for natural gas demand: three by the International Energy Agency (IEA), one by The Institute of Energy Economics, Japan (IEEJ) and four by Rystad Energy. Each scenario highlights the ongoing and future need for gas in the energy system, even in scenarios where a substantial integration of renewable energy is anticipated. Given that all scenarios have varying underlying assumptions, there are a wide range of outcomes across the scenarios, highlighting the uncertainties surrounding the outlook for gas demand.

In the context of energy scenarios analysis, it is important to highlight the different methods in modelling the scenarios. **Forecasted scenarios** are forward-looking projections based on actual historical data, current trends and policies shaping the projection (IEA Stated Policies, Announced Pledges, IEEJ Reference case). On the other hand, **back casted projections** (IEA Net Zero, Rystad Energy scenarios) start with an assumed future outcome, such as specific emission reduction and energy system characteristics, and are modelled backwards to determine possible trajectories and assumed changes needed to arrive at that future from the present system.

For example, the scenarios outlined in Figure 56 and the following text are built on assumptions requiring significant behavioural changes and commercialisation and widespread deployment of a wide range of emerging, new, and existing technologies, both in the private and public spheres globally. Failure to achieve these behavioural changes or deployment scales could lead to a deceleration in decarbonisation efforts and thereby different trajectories across various sectors, including power, industry, buildings, and transportation. Long-term back cast modelling is based on a set of critical assumptions about technology paths that it employs to align the current state to an outcome over several decades from the current situation. It is a highly valuable tool to use as a

[12] *All historical and forecasted values are scaled to be identical in 2022 to account for different heating and caloric assumptions. This figure shows the 2022 version of NZE, APS, and STEPS and the NZE 2022 version from the IEA WEO 2022 presented is quite similar and aligned to the version published on 26th September 2023. Any reference to the IEA NZE in this report is connected to the 2022 edition of the NZE scenario.*

guide; however, it is not a perfect predictor of technology evolution, and it is also not a suitable replacement for energy supply planning. This is particularly true for natural gas, where production needs to be developed ahead of demand to avoid shortages and price shocks, further emphasising the need for long-term system planning of energy.

Table 4: Selected assumptions across scenarios[13]

Scenarios	Power Generation in 2050	Final energy consumption CAGR	Share of electricity in final energy consumption (2050)	Goals & policies assumptions
IEEJ Reference	30% Gas, 36% Renewables Renewables vs 2021: x2.2	1.3% 0.5%	29%	Incorporates past trends and expected effects of policies and technologies to date, while reconciling energy security and climate action
IEA STEPS (2022)	13% Gas, 65% Renewables Renewables vs 2021: x4.0	1.1% 0.3%	28%	Reflects current policy settings incl. European Green Deal, US Methane Emissions Reduction Action Plan, China 14th Five-Year Plan.
IEA APS (2022)	6% Gas, 80% Renewables Renewables vs 2021: x6.0	0.3% -0.1%	39%	Assumes commitments incl. Nationally Determined Contributions under the Paris Agreement, EU Fit for 55 package, and G7 Commitment will be met on time
IEA NZE (2022)	0.1% Gas, 88% Renewables Renewables vs 2021: x8.0	-1.1% -0.6%	52%	Assumes universal access to electricity and clean cooking are achieved by 2030 and relies solely on emissions reductions within the energy sector to achieve 2050 net zero emissions
RE 2.2-DG	12% Gas, 69% Renewables Renewables vs 2021: x3.8	1.2% -0.0%	22%	Corresponds to global warming limited to 2.2°C with gas plays a crucial part facilitating the decarbonization process
RE 1.9-DG	7% Gas, 82% Renewables Renewables vs 2021: x6.1	0.8% -0.3%	28%	Corresponds to global warming limited to 1.9°C with a more gradual transition towards renewable energy
RE 1.6-DG	3% Gas, 92% Renewables Renewables vs 2021: x9.7	0.2% -0.5%	37%	Corresponds to global warming limited to 1.6°C and requires a considerably aggressive transition, which the world has almost sufficient manufacturing capacity to meet
RE 1.5-DG	1.4% Gas, 94% Renewables Renewables vs 2021: x10.9	-0.7% -0.3%	41%	Corresponds to global warming limited to 1.5°C and envisions net zero emissions by 2050, but requires extensive carbon removal and investment in hydrogen and biofuels

Source: IEA; IEE Japan; Rystad Energy

IEA: IEA's three scenarios comprise the Stated Policies Scenario (STEPS), the Announced Pledges Scenario (APS), and the Net Zero Emissions by 2050 Scenario (NZE 2022). STEPS is aligned with the 2.0-degree scenario under the Intergovernmental Panel on Climate Change's (IPCC) Sixth Assessment Report (AR6) carbon budget and examines how global energy markets could evolve if countries follow through on announced strategies and targets related to energy production, consumption, and emissions reduction. The APS is aligned with the 1.8-degree scenario under the IPCC AR6 carbon budget and assumes countries meeting national targets towards 2030 and beyond. The APS provides an outlook for exporters of fossil fuels and low emissions fuels such as hydrogen, shaped by what full implementation means for global demand and the timely and complete attainment of country-level goals for electricity access and 'clean' cooking. In the APS, low-emissions hydrogen production rises to reach 30 million tonnes of hydrogen per year in 2030. The NZE (2022) is aligned with the 1.5-degree scenario under the IPCC AR6 carbon budget and envisions a world in which all CO2 emissions released to the atmosphere are offset, effectively resulting in net zero emissions by 2050. This requires tremendous effort in energy mix transition, with renewable energy and green fuels rapidly replacing traditional energy and wide adoption of carbon capture and storage technology. Under the IEA NZE (2022), low emission fuels comprise 20% of all liquid, solid and gaseous fuels used worldwide in 2030 and 65% by 2050.

IEEJ: The IEEJ Reference Case scenario reflects the anticipated effects and progress from current energy policies and available technology. It assumes a gas growth rate of about 1.3% to continue forward with increased adoption of renewables towards 2050. The scenario predicts a continued reliance on traditional energy sources in consumption and energy demand driven by India, the Middle East, ASEAN, and North Africa. Natural gas is also widely assumed as the stabiliser amid energy security concerns and serves as a key energy source replacing coal in large coal consuming countries throughout Asia. Gas is also assumed to be the largest source of electricity generation in 2050. Natural gas-based blue hydrogen and blue ammonia will play a crucial role in the decarbonisation of fossil fuels. As such, the IEEJ stresses the need for the natural gas market to be stabilised to ensure the introduction of blue hydrogen/ammonia as their competitiveness in materialising is largely dependent on the price of gas.

[13] *Final energy consumption growth percentages are represented as the compound annual growth rates (CAGR) between 2021 to 2030, and 2030 to 2050. In 2022 the power generation was made up of 22% natural gas and electricity made up 17% of total final energy consumption.*

2 / Looking to 2030 and beyond

Rystad Energy: Rystad Energy's four scenarios anticipate what would be required to limit global warming to 1.5 degrees, 1.6 degrees, 1.9 degrees and 2.2 degrees. The scenarios are in accordance with the greenhouse gas emissions budgets in IPCC AR6 which looks at limiting global warming to certain degrees Celsius with a 50% probability. Each scenario has a varying assumed optimal resource mix to stay within the designated carbon budget. As the scenarios are based on emission budgets, there is a range of outcomes associated with the pace of curbing various fossil fuels to meet the budgets. The scenarios showcase Rystad Energy's view on the most likely pace of transition for all energy sources.

While most scenarios show a long term gradual downward trajectory in natural gas demand towards 2050, the rate of decline varies wildly across scenarios. IEEJ Reference Case, on the other hand, envisions natural gas to increase gradually towards 2050, peaking beyond this timeframe. This is primarily driven by non-OECD countries led by India and Indonesia, where coal to gas switching is expected to rise. Its share in the primary energy mix increases, from just above 23% in 2021 to 24% in 2030, 26% in 2040 and 27% by 2050. Due to coal's decline, gas becomes the second largest fuel in the mix after 2030.

The delta between the Rystad Energy 1.5-degrees scenario and the IEEJ Reference Case is about 4,700 Bcm, which is more than the total global gas consumption today of around 4,000 Bcm. As such, massive developments in gas infrastructure are required in the future to meet the IEEJ Reference Case's targets. Comparing it with IEA's stated policies and announced pledges, the difference is about 1,200 Bcm and 2,900 Bcm respectively. The IEA's STEPS is positioned between Rystad Energy's 1.9-degree and 2.2-degree scenarios. Looking towards 2030, the industrial sector emerges as the primary driver of gas demand growth, particularly in emerging economies across Asia and Africa. STEPS also assumes larger scale electrification. In the IEA's APS, there is an accelerated growth in renewables, resulting in a reduction of total gas consumption within the power sector, despite the incorporation of supplementary capacity to bolster flexibility requirements. In addition, the shift in demand directly gravitates towards renewables or other low carbon emission alternatives, thereby bypassing coal-to-gas switching. Additionally, global clean hydrogen production reaches 30 million tonnes per year in 2030, enabling natural gas substitution in the industrial sector, especially in refineries. By 2050, clean hydrogen trade patterns are expected to be well established, with Australia and the Middle East as the largest exporting regions.

While on the most aggressive energy transition side, the IEA's NZE (2022) outlines a pathway for the global energy sector to achieve net zero CO2 emissions by 2050, requiring high investment in renewables, CCUS, hydrogen, and biofuels. In the NZE (2022), natural gas demand falls by 20% to 2030, and is 70% lower than 2021 by 2050. By 2050, the NZE (2022) assumes 190 Bcm of natural gas used in non-combustion sectors such as chemical, 100 Bcm is used in power plants equipped with CCUS, and over 560 Bcm used with CCUS to produce hydrogen and a further 150 Bcm used with CCUS in industry. Over 25% of the hydrogen produced in 2050 is converted to hydrogen-based fuels such as ammonia, methanol, and synthetic hydrocarbons. Biogas is also assumed to reach more than 400 Bcm by 2050, where around 65% is biomethane, mostly injected into existing gas distribution networks. Despite the decline, natural gas continues to remain a critical source of power system flexibility and industrial feedstock, contributed by potential synergies with CCUS.

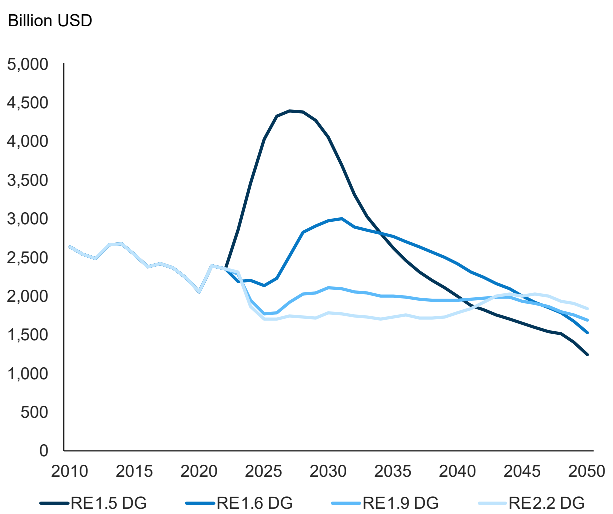
Rystad Energy's 1.5-degree scenario envisions a net-zero society by 2050 and is aligned with the IEA's NZE (2022). As such, the pace of decline in natural gas in both the NZE (2022) and Rystad Energy 1.5-degree is relatively similar, with only slight variations post-2035, likely driven by differences in methodology and assumptions. The Rystad Energy 1.6-degree scenario follows a similar short-term trend as the IEA STEPS, where gas demand is expected to increase and peak in 2030 at 4,267 Bcm, before declining to 1,854 Bcm in 2050. The short to medium term increase in gas demand is driven by coal to gas switching in Asia. Post 2030, renewables are expected to grow significantly, replacing the share of natural gas in power across Europe and North America. Additionally, alternative lower carbon fuels such as green hydrogen begin to increase in scale, replacing natural gas in the industrial sector towards 2050.

In Rystad Energy's 1.9-degree scenario, natural gas demand peaks in 2034 at 4,705 Bcm before declining to 3,361 Bcm in 2050. Natural gas is widely considered an important part of the transition towards a low carbon society in markets that are currently highly dependent on higher emitting coal and oil. Natural gas demand continues to grow, replacing coal in Asia while renewables take shares from natural gas in Europe, the Middle East, and North America. Natural gas is also set to be the main source of power generation during periods of intermittency of renewables. However, growth in battery storage capacity, accumulating to nearly 67 TWh in 2035, supports the case for declining use of gas post-2035, primarily to meet short duration dispatchable needs. Similarly, the industrial sector is expected to increase its rate of decarbonisation post-2030, primarily through the uptake of clean hydrogen. Clean hydrogen and ammonia are expected to comprise around 12% of the energy mix by 2050, from less than 1% in 2022. However, the uptake of replacement fuels is gradual, as heat-intensive processes within the industrial sector continue to rely on both coal and natural gas as an affordable and practical solution.

Rystad Energy's 2.2-degree scenario provides a plausible upper bound beyond the 1.9-degree scenario. In the 2.2-degree scenario, natural gas assumes a central role in facilitating the transition to a low carbon global environment, particularly within major natural gas markets such as Asia, North America, and the Middle East. Global demand for natural gas remains on an upward trajectory in the power sector until 2030, attributed to the transition from coal to gas in the power sector across Asia and lower investments in new renewable capacity. Both North America and the Middle East see continued growth in natural gas demand into 2030, while European natural gas demand declines, driven by an increased pace of electrification across all sectors.

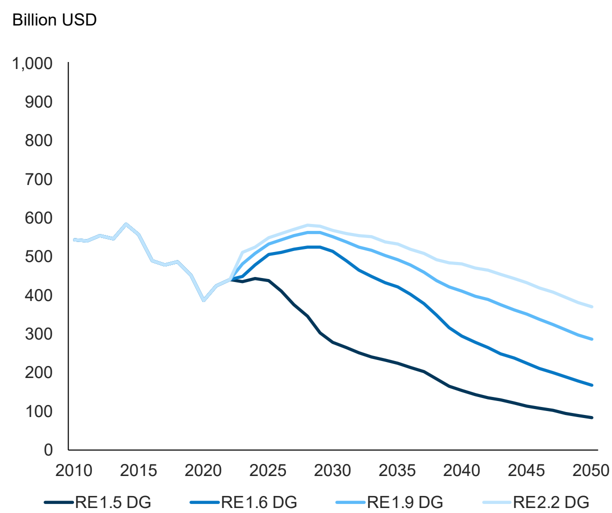
Natural gas investments still crucial in the long run

Figure 57: Annual global energy CAPEX investments across varying degree-scenarios, real 2022[14]



Source: Rystad Energy

Figure 58: Annual global gas CAPEX investments across varying degree-scenarios, real 2022[14]



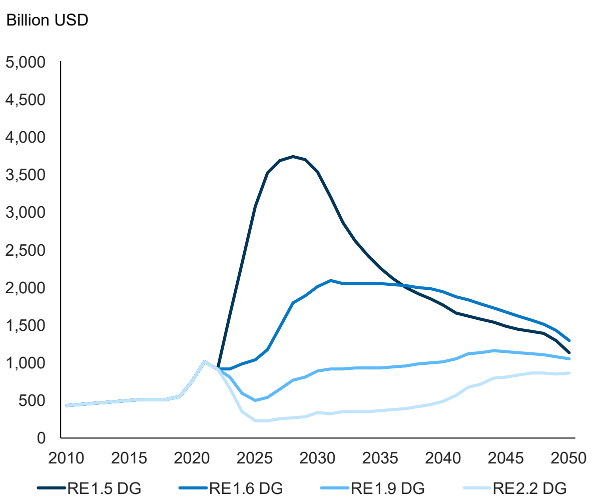
Source: Rystad Energy

Figure 57 showcases annual energy investments across four distinct Rystad Energy scenarios: 1.5, 1.6, 1.9 and 2.2 degrees. Notably, in high-renewable energy penetration scenarios such as Rystad Energy's 1.5-degree scenario, there is a need for heightened investments towards 2030. These investments are pivotal to facilitate the extensive scale-up of renewable energy, clean fuels, and CCUS initiatives mandated by this scenario. Specifically, in the1.5-degree scenario, annual energy invest-ments are anticipated to peak just below USD 4.3 trillion in 2027, a figure exceeding that of the 1.9 and 2.2-degree scenarios more than twofold. This stark contrast underscores the substantial financial commitment required to transition to a decarbonised energy system swiftly and aggressively.

Global renewable energy investments are compared to global natural gas investments (figures 57 and 58),

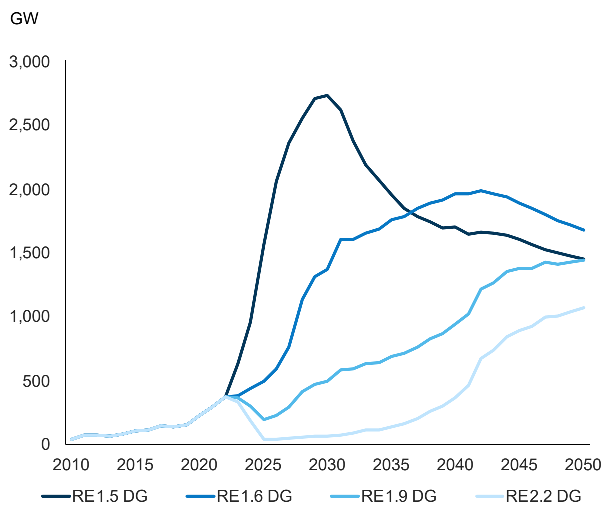
[14] The Rystad Energy 1.5-degree scenario has similar gas demand trajectories as the IEA NZE (2022) scenario.

Figure 59: Annual global renewable energy CAPEX investments across varying degree-scenarios, real 2022[14]



Source: Rystad Energy

Figure 60: Annual renewable capacity additions across Rystad Energy scenarios[14]



Source: Rystad Energy

From this there is a clear call for greater gas investments in the long term, even for aggressive decarbonisation scenarios such as Rystad Energy's 1.5-degree scenario. In this scenario, the global natural gas investments are hovering around 300 to 400 billion between 2023 and 2030 and then declining to 80 billion USD by 2050. This scenario also has the highest level of uncertainty and faster-than-expected transition away from high-emitting fossil fuel sources. However, this scenario could call for increased gas demand and still be in accordance with the carbon budget, e.g., faster phase out of coal and switching with gas would result in higher gas demand whilst meeting the carbon budget.

The 1.5-degree scenario shows the importance of gas within the energy landscape in bridging the transition to renewable energy alternatives. Rystad Energy's 1.6, 1.9 and 2.2-degree scenarios show gas investments increasing in the short to medium term, before gradually declining towards 2050.

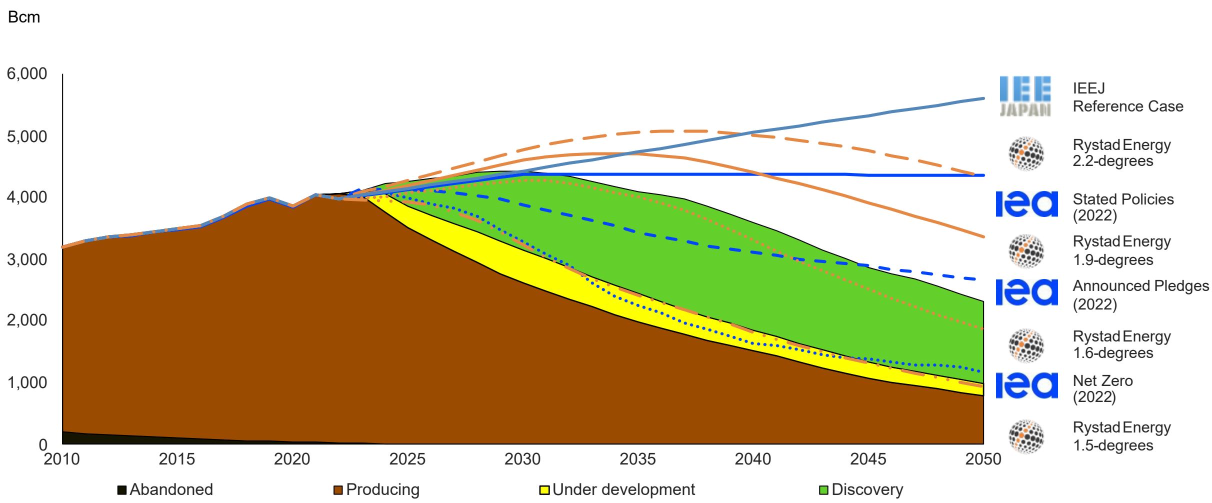
There is an unprecedented need for accelerated investments in renewables to meet lower temperature targets. With reference to Figure 60, the 1.5-degree scenario expects around 2,800 GW of renewable capacity additions in 2030, around 5.5 times higher than the annual capacity additions in the 1.9-degree scenario at 497 GW. In a time where the majority of the renewable supply chains are concentrated in China, this may potentially introduce similar single-source dependency risks, putting energy security at risk. Additionally, the surge in large-scale renewable investments required to meet lower temperature climate targets coincides with a period of rising investments and sentiment in the oil and gas sector. It could be challenging to obtain adequate capital to meet both renewable investments while maintaining the pace of oil and gas developments. This adds risks to both existing and future energy systems and calls for sound policies and incentive frameworks to facilitate sustainable development.

Most scenarios call for higher natural gas production

This section compares the different demand scenarios with producing and approved natural gas supply. With reference to Figure 61, total producing, and approved gas production is expected to reach 4,098 Bcm in 2023. These output volumes are projected to decline to 3,134 Bcm in 2030 due to asset maturation and natural decline. The projection indicates a further decline to 1,849 Bcm in 2040, followed by a decrease to just under 1,000 Bcm, falling to 974 Bcm in 2050.

In the short to medium term, gas supply growth is primarily

Figure 61: Global gas demand scenarios from various institutions versus operational, approved and discovered assets (2010 – 2050)[15]



Source: IEA; IEE Japan; Rystad Energy

driven by the Middle East, notably Qatar's North Field East expansion for LNG exports and increased non-associated gas production in Iran, Saudi Arabia, and the United Arab Emirates. The United States is set to increase production from shale gas resources such as Marcellus and Utica, as well as Permian Basin associated gas. In Asia, China has committed to boosting domestic gas production through conventional onshore and shale play in the western territory of Xinjiang, while Southeast Asia's production is set to stabilise as investments offset declining fields. Potential upside is also present in Africa, led by developments in Mozambique, where force majeure in 2021 is gradually being lifted for developments to resume.

In the coming decades, there is a call on exploration and additional discoveries of gas projects to meet increasing demands across all scenarios, except the IEA's NZE (2022) and Rystad Energy's 1.5-degree scenario. In the NZE (2022) and 1.5-degree scenarios, the existing and under development gas fields are sufficient to meet future demand. However, mid-, and downstream gas investments are still required to facilitate for the growth in export and to meet rising demand in new regions. As shown in Figure 61, production from "Discovered" assets is required to meet future demand. These are assets that have proven reserves but have not progressed to appraisal or development/FID stage. Even including "Discovered" assets, supply is still not sufficient to meet demand in the APS and 1.9-degree scenario. This is critical to note as there is a reasonable level of risk that assumptions and policies do not deliver as anticipated, resulting in higher than anticipated gas demand. In that situation, supply could be unable to react quick enough for demand to be met, leading to a potential energy security crisis, and growing global emissions by increased utilisation of coal. As such, it is critical to have sufficient available supply that can be leveraged to meet the uncertain surges in future demand. Similarly, regasification and liquefaction infrastructure must be in place in vulnerable areas in case of shortfall of local production or imports, as seen in Europe with the reduced Russian piped-gas imports.

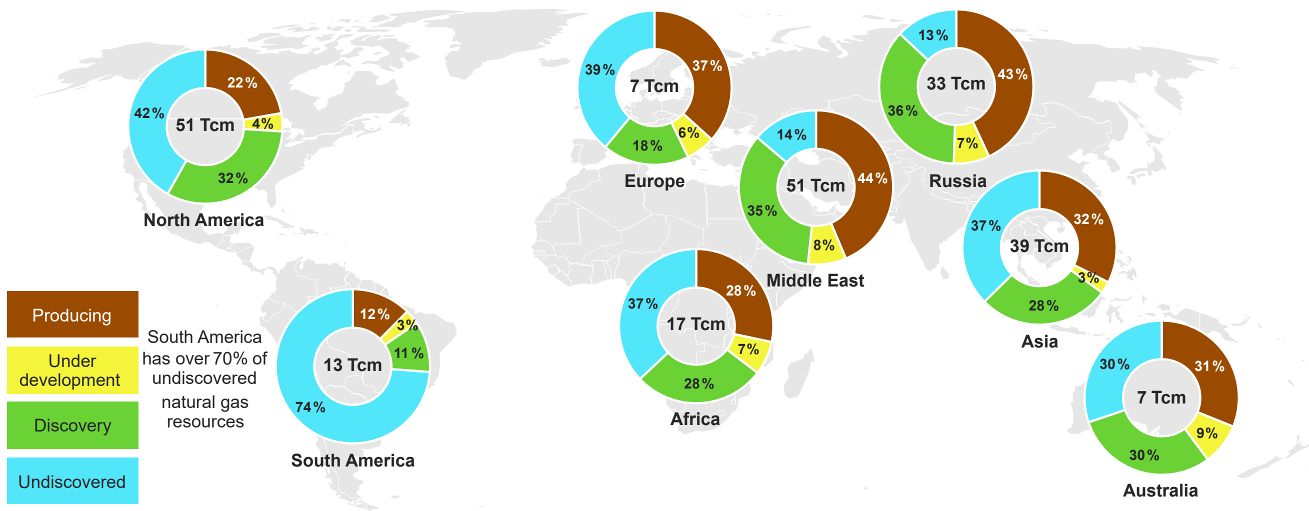
As of August 2023, there are more than 210 Tcm of gas reserves, underscoring the availability of global gas reserves to fulfil even higher gas demands than that presented in the scenarios. That said, prioritising the cost-effective and accessible monetisation of gas is important. Gas resources that are deemed economically unviable at current and forecasted prices would remain undeveloped, particularly in the current policy environment, both political and financial. In particular, there are still significant gas reserves in the ground that could enter the future gas market, seen by both the discovered and undiscovered resources in Figure 62 that form about 62% of all gas reserves worldwide, especially in South America, Asia, and Africa. Future exploration activity and growing local demand could prove these resources to be competitive and demanded which in turn would lift the demand and exportable potential in these regions.

Monetisation of associated gas[16]: Another way to bolster production, while reducing emissions, is to monetise

[15] All historical and forecasted values are scaled to be identical in 2022 to account for different heating and caloric assumptions.

[16] Natural gas found within crude oil deposits, either dissolved in the oil or as a free gas layer above the oil in the reservoir.

Figure 62: Existing gas production by regions



Source: Rystad Energy

associated natural gas, which is often flared or vented during oil production. This natural gas can be captured and utilised in the local market, however, often the natural gas is impossible to export due to lacking infrastructure. Advances in technology have enabled economic deployment of gas-to-liquids (GTL), gas-to-power (GTP), and gas-to-chemicals (GTC) conversion, with GTP being the most common approach. In many cases though, there is a business case for infrastructure to be built for associated gas, and there are many case studies across the world where associated gas becomes a viable commercial supply source. This is important for energy-poor regions like Africa, which lacks reliable electricity access yet accounted for around 10% of global flaring volumes in 2022. Monetising associated gas would reduce flaring and venting and contribute positively towards the environment by reducing carbon and methane emissions. However, with restrictive policies on fossil fuel infrastructure finance, these investments are facing ever-growing barriers too.

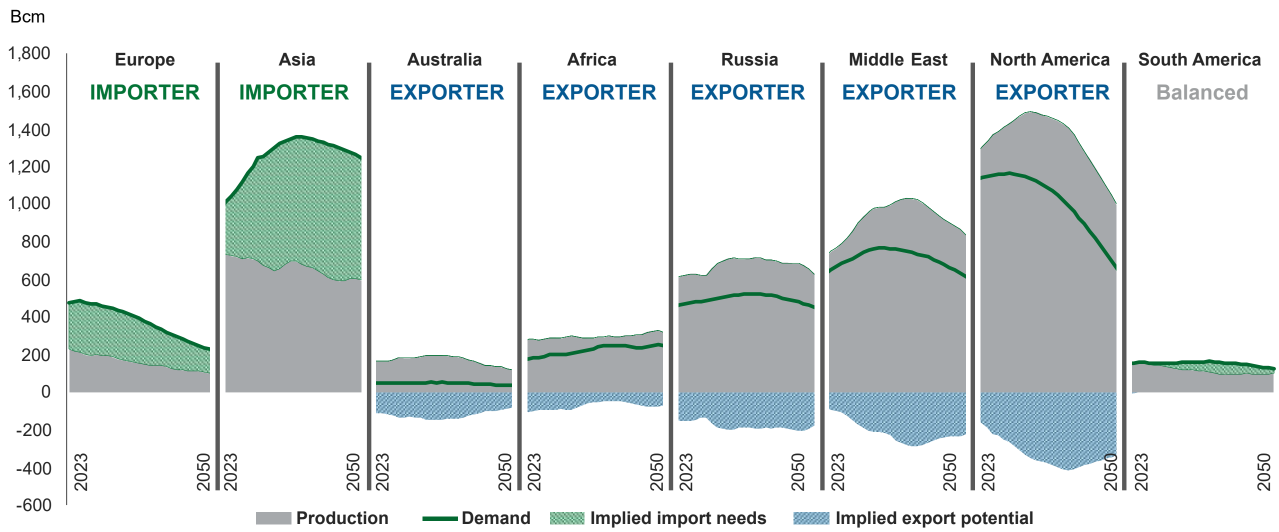
While global supply and demand will eventually balance, trading is vital for achieving regional equilibrium. Addressing country and regional shortfalls involves developing new infrastructure such as pipelines and LNG facilities. To delve deeper into regional balances, the following trade balance sub-chapter explores the regional traits of future gas markets.

Future balances of trade flow

The Rystad Energy 1.9-degree scenario is used for future trade balances analysis (Figure 63). Looking ahead to 2030 and beyond, Asia and Europe continue to be the largest net importers of natural gas. To meet the 1.9-degree scenario transition pathway, gas imports into Asia are anticipated to increase from 257 Bcm in 2022 to over 533 Bcm in 2030, peaking around 2040 at 725 Bcm. To support this growth, there is a wave of LNG import terminals under construction in the region. Growth after 2030 would be centred in China, with increased piped gas imports from Russia and Central Asia. Two major Russian pipelines — the 10 Bcm Far East pipeline and the 50 Bcm Power of Siberia 2 — are anticipated to commence operations by 2026 and 2030, respectively. Additionally, the Central Asia-China pipeline D is expected to start operating by 2026. At present, the Power of Siberia 1 pipeline is gradually increasing its capacity to 38 Bcm by 2025, boosting China's piped gas imports from 69 Bcm in 2022 to 136 Bcm in 2030.

Following the Russia-Ukraine war, European policymakers are striving to reduce reliance on Russian energy imports. Europe's REPowerEU Strategy aims to replace 101.5 Bcm of pre-war Russian piped gas in the short term with LNG and alternative pipeline imports. Despite a declining trend in domestic gas production, Europe is likely to remain import dependent even as gas consumption decreases. To offset the loss of Russian gas, Europe needs to increase LNG imports and decrease gas

Figure 63: Gas production and import/export volumes[17]

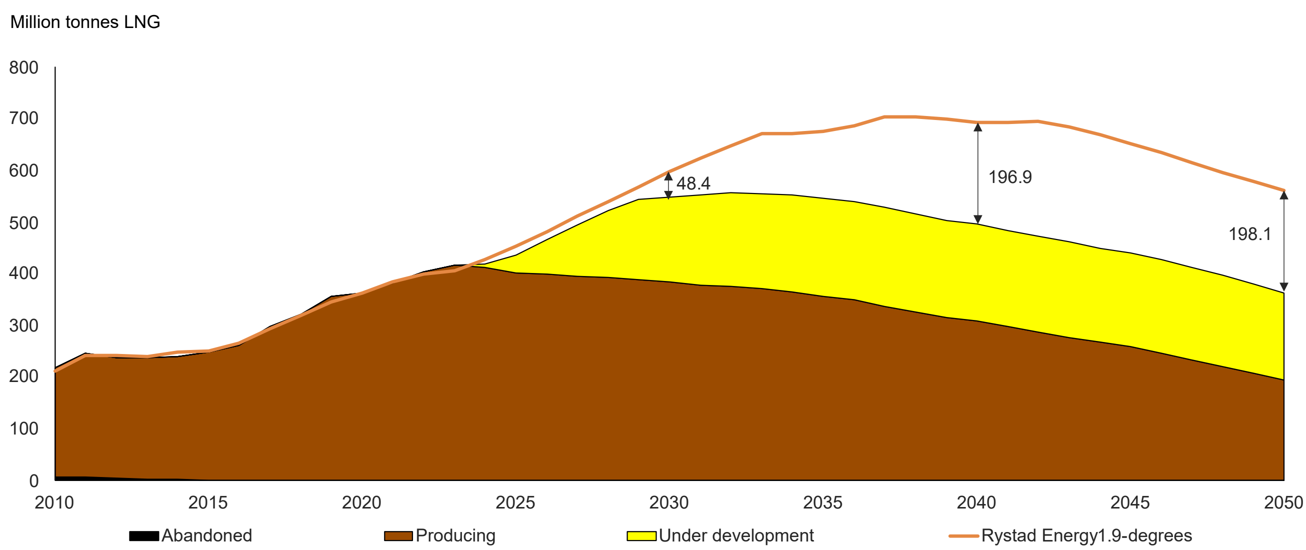


Source: Rystad Energy

usage. Much of the additional LNG required will come from uncontracted volumes, portfolio players, alongside contracted volumes from Qatar, the United States, and Nigeria.

LNG plays a key role in the global trade balance, offering flexibility and reaching across regions. In Rystad Energy's 1.9-degree scenario, global LNG trade is expected to remain robust in the short to medium term, although a gradual decline would be expected post-2040. Nonetheless, there is a clear call for additional LNG supplies even in the long term as upstream assets deplete. From Figure 64, about 48.4 million tonnes of new LNG supplies are needed by 2030, rising to 196.9 million tonnes in 2040 and 198.1 million tonnes in 2050. This is largely driven by Asia, Middle East, and Africa, with an accelerated pace of renewable uptake only occurring from 2035 onwards. However, given the uncertainties surrounding the assumptions, there are risks of

Figure 64: Potential LNG import scenario against operational and approved production (2010 – 2050)



Source: Rystad Energy

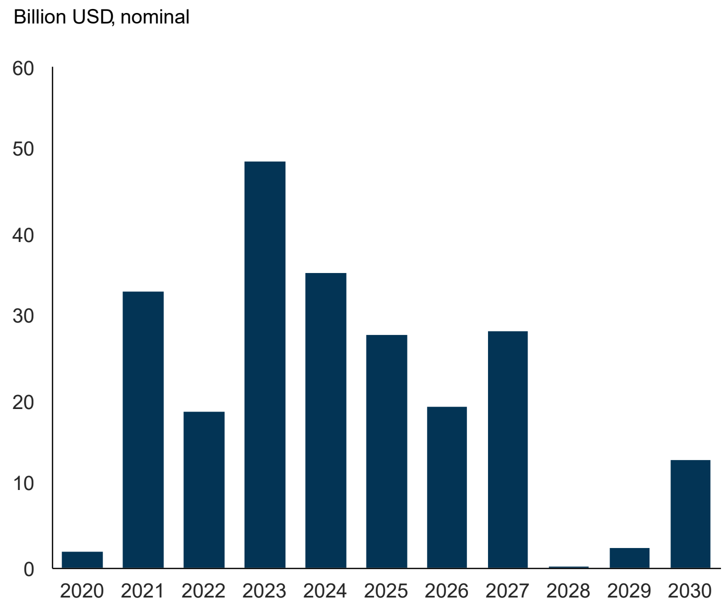
[17] *The illustration is based on information available on the competitiveness and availability of gas assets in September 2023. Accelerated regional exploration efforts could change this picture in the future.*

an even larger supply shortage, if demand were to falls slower than expected.

The Middle East, led by Qatar, will be an important region in the LNG landscape. With ongoing expansion plans at the huge North Field, Qatar could potentially boost LNG export capacity to 126 MTPA by 2030, from 77.8 MTPA as of August 2023. Given the low-cost production of North Field East fields and shipping cost advantages, Qatar is primed to serve both European and Asian LNG demand in the long term.

North America is also well positioned to lead as the top global LNG exporter in the long term. Its gas production is projected to outpace demand through 2050. The strong outlook for gas demand has already triggered a wave of FIDs for gas infrastructure (pipelines, liquefaction, and regasification) which is expected to continue in the coming years. North America has the resources available to help close the global supply-demand gap, but continued investment in gas infrastructure will be needed to mitigate market volatility and periods of extreme market tightness to achieve energy security. Around 78 million tonnes of FID-ed LNG capacity is expected to come online in North America between 2024 and 2027.

Figure 65: Greenfield LNG investment by commitment/FID year (2023 – 2030)



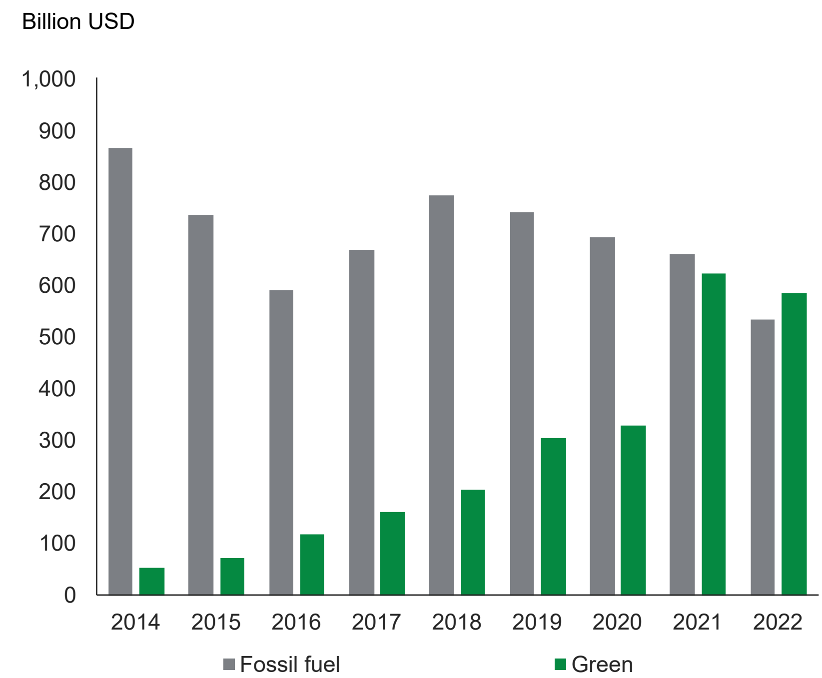
Source: Rystad Energy

Avoiding future shortages of gas hinges on investments in gas assets and infrastructure. Rystad Energy estimates reveal a need for around $175 billion in green-field LNG investments between 2023 and 2030 to expand LNG capacity (Figure 65). The next few years are particularly critical, as the LNG market is anticipated to remain finely balanced, with additional supply required to cater to the growing demand, as illustrated in the figure above. To ensure the necessary investments and financing, regulators and financial institutions need to ensure that sufficient capital is allocated and balance the risk of a major global under-supply shock with a risk of under-utilised assets in the future. Having reserve capacity for a secure and flexible energy system is better than being unable to meet demand. The latter is more damaging to economies, livelihoods, and the environment – when economic development is halted in areas with low purchasing power and when dirtier alternatives are used to fill the gap, as seen in 2022.

Addressing uncertainties in future gas policies

The large range of differences in assumptions about future natural gas demand (especially in the medium to long term), coupled with a high level of misalignment between near-term supply needs with policy and financial developments, creates a high level of risk of future supply imbalances. Despite recent optimism around certain LNG investments, the investment growth is occurring on the back of a prolonged period with low investments, and the total level and off-take agreements are still short of what is needed to produce sufficient supply to rebalance and ensure security in the global energy markets. This risk means that the current energy environment may experience future crises as seen in 2021 and 2022, with more severe and

Figure 66: Green debt issuance against fossil fuel debt issuance



Source: Bloomberg League Tables

frequent price and demand shocks. This would in turn cause disruptions in economic development and environmental consequences – especially in the developing world, where demand for natural gas could fail to be met, and greater use of coal, oil, and biomass use may occur.

Gas is projected to remain a key component in the energy policies of major global consumers at least until 2050, however, there are challenges and significant uncertainty on how future gas projects will be developed and maintained. These uncertainties encompass financing challenges, carbon pricing, and public sentiment.

Financing: Considering the Russia – Ukraine conflict, the Biden Administration announced an agreement committing the United States LNG industry to supply at least 50 Bcm of additional US LNG until at least 2030, equating to around one-third of the EU's gas imports from Russia in 2021. This is widely regarded as a window of opportunity for US LNG project developers which will require an increase in export capacity. However, on top of the struggle to secure long term off-takers to underwrite financing, financing conditions have become considerably more difficult, with higher interest rates underpinning uncompetitive project economics. Though this is largely to penalise the financing of highly polluting sectors such as coal, the gas industry has also been affected. Leading financial institutions have taken a categorical stance, vowing to cease new project funding for future oil and gas projects, especially on the production side. For example, large banks such as ING, BNP Paribas and HSBC have committed to seize funding for new oil and gas projects. This shift is driven by a substantial transformation in the policies of lenders, and other financial enablers, aligning with both their net-zero scenario assumptions and targets set by their respective home countries. Additionally, with reference to Figure 66, debt issued for fossil fuel projects have been on a decline and was surpassed by green projects in 2022. The inability to secure financing will result in delays in project FIDs, placing more stress on an already tight global gas market. For example, the FID of NextDecade's Rio Grande LNG project has been repeatedly delayed due to rising borrowing and labour costs, and French bank Societe Generale SA withdrawing as the lead bank of the project in 2022.

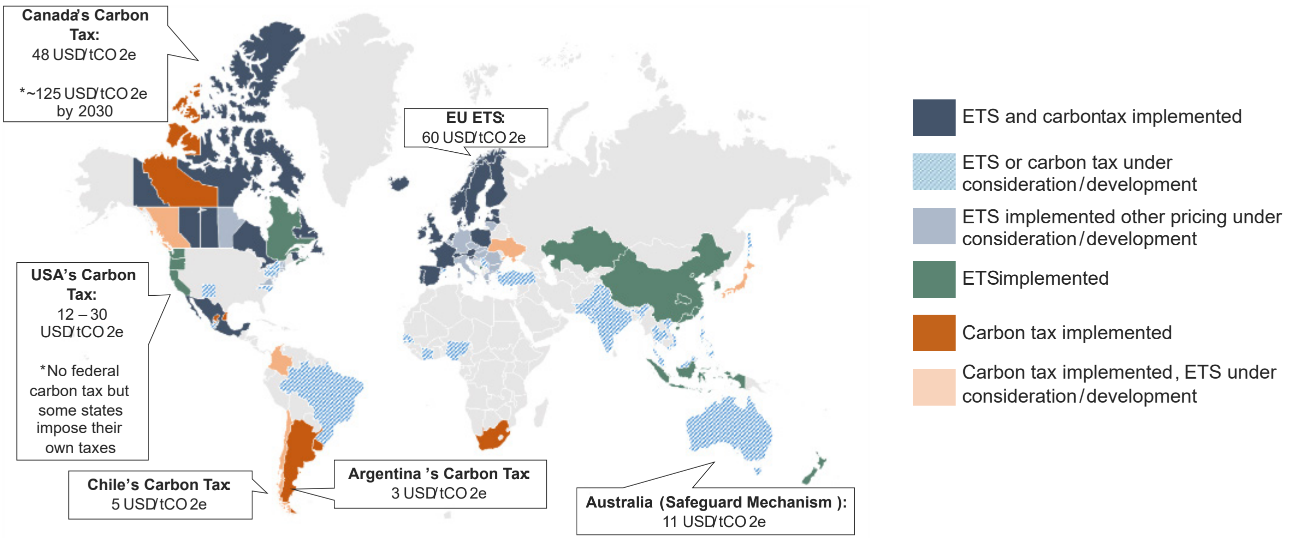
As such, for the needed gas projects to proceed, policymakers should work closely with financiers to create a more favourable financing environment for project developers. This collaboration can help mitigate the potential impact of transition risks like stranded assets, facilitating the development of necessary assets and infrastructure, while providing a more effective lever to enforce environmental performance.

Carbon pricing: As of August 2023, according to the World Bank carbon pricing dashboard, only 23% of global greenhouse gas emissions are covered by existing carbon taxes or emissions trading schemes (Figure 67), amounting to 11.7 giga-tonnes[18] of CO2 equivalent out of the total 50.7 giga-tonnes emitted in 2023. This is insufficient to incentivise large-scale switching towards cleaner alternative energy sources, including gas and renewables.

Carbon pricing is a key enabler for coal-to-gas switching,

[18] *The World Bank Carbon Pricing Dashboard: https://carbonpricingdashboard.worldbank.org/*

Figure 67: Global carbon pricing map



Source: Rystad Energy; World Bank

increasing the attractiveness of gas as a cleaner fuel, and renewables as an emission-free energy source. For the world to accelerate the fuel switching away from emission intensive sources such as coal and fuel oil, carbon pricing needs to be widely adopted. And the price needs to be commensurate to the real cost of emissions to disincentivise the use of emission-intensive sources. In Japan for example, the Ministry of Economy, Trade, and Industry has commited to reducing coal in the energy mix from 32% in 2019 to 19% by 2030, while scaling renewables to almost 40% by 2030, from 18% in 2019. However, its current carbon tax stands at USD 3 per tonne of CO2, while the IEA estimates a carbon price of at least USD 130 per tonne of CO2 is required for developed countries, for transition to take place effectively. Meanwhile, carbon pricing levels are globally far below this threshold, as illustrated in Figure 67 above.

The EU Carbon Border Adjustment Mechanism (CBAM) aims to addresses unequal carbon taxation levels by taxing the “untaxed” carbon emissions for imports into the EU. As part of the EU Green Deal, the CBAM will apply a carbon tariff on carbon-intensive imported products. EU importers will buy carbon certificates corresponding to the carbon price that would have been paid had the goods been produced under the EU’s carbon pricing rules. The measure is designed to reduce carbon leakage and ensure a level playing field for importers and the domestic producers. As such, EU importers will be more cautious in purchasing decisions, potentially favouring suppliers with lower carbon footprint.

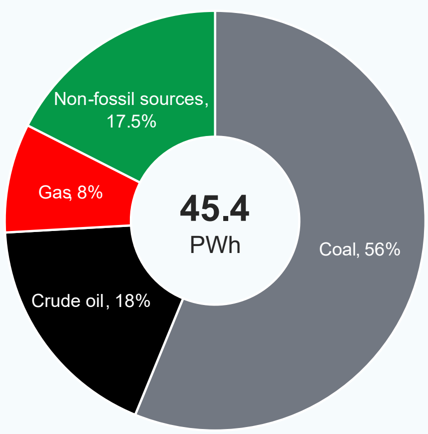
In conclusion, there is a growing gap between the trajectory of supply development and plausible demand for natural gas that could be risky for economical and decarbonisation developments. There is a higher possibility of heightened demand and price shocks in the coming decades – like the ones seen in 2021 and 2022 – likely to be driven by muted supply outlooks and challenging financial conditions in a gas market that seems to be highly fragile and thinly balanced. Thus, it is crucial for governments, financial institutions, and energy companies to align efforts and incentives to ensure reliable, sustainable, and affordable future energy markets.

Case study: The role of gas in China's energy transition

China, the world's most populous nation and a global economic powerhouse, stands at the crossroads of energy demand and sustainability. With a population exceeding 1.4 billion people, the country's energy needs are vast and ever-expanding. As China strives towards its environmental targets of peak carbon emissions by 2030 and carbon neutrality by 2060, its energy mix will certainly evolve. This case study highlights some of the recent key energy-related policies and underscores the crucial role of gas in China's journey to fulfil its energy requirements while achieving its emission reduction targets. China's power demand is set to rise in the coming decades, and to cope with this, they plan to build new nuclear facilities to provide base load power, increase intermittent renewable energy sources, and accelerate gas-fired capacity development. These measures collectively aim to replace the historical reliance on coal and diversify the country's power mix.

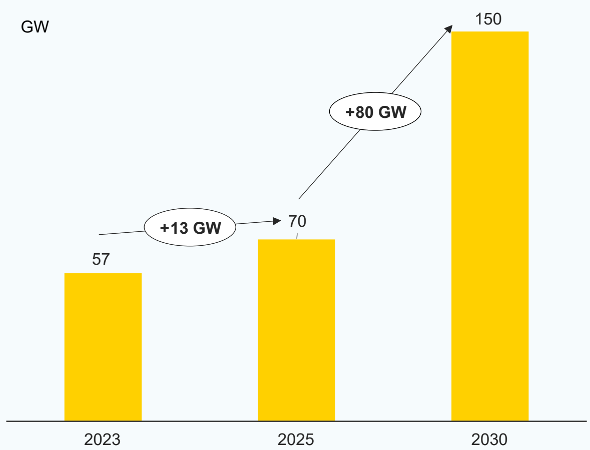
Historically, China has relied on domestically produced coal as its main energy source. Coal comprised 56.2% of the country's energy mix in 2022 (Figure 68), advancing its market share by 0.2% from 2021. As of August 2023, China has 243 GW of coal-fired power plants under construction and permitted, indicating that coal will continue to be the primary energy source for the country at least until peak emissions by 2030 is reached. After which, coal as the baseload energy supply would need to gradually be phased out, with other cleaner sources such as nuclear stepping up. In August 2023, the Chinese government approved the construction of six new nuclear reactors as part of its plan to reduce carbon dioxide emissions by more than doubling nuclear power capacity this decade. As of June 2023, China had 57 GW of nuclear generating capacity. The government plans to expand the scale to 70 GW by 2025 and up to 150 GW by 2030 (Figure 69), where it is likely to become the world's largest generator of nuclear energy, well ahead of US (95 GW) and France (61 GW). China has been steadily expanding its nuclear fleet

Figure 68: China total energy consumption by energy source (2022)[19]



Source: National Energy Administration; National Bureau of Statistics; National Development and Reform Commission

Figure 69: China's announced nuclear capacity developments



Source: National Energy Administration; National Bureau of Statistics; National Development and Reform Commission

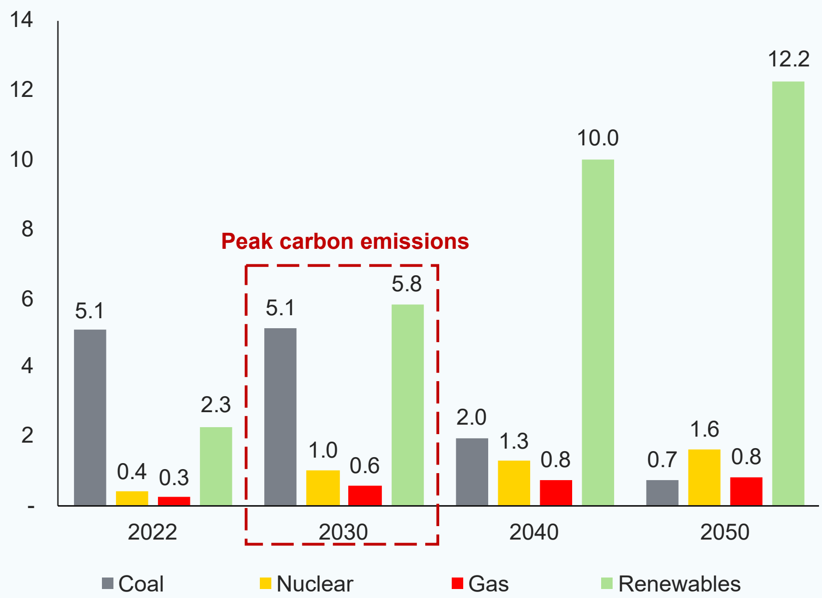
[19] *Non-fossil sources include nuclear, hydropower, wind, solar and geothermal.*

to provide stable, reliable, emission-free baseload electricity for its growing economy. Alongside hydropower, nuclear is anticipated to replace coal as the primary baseload power source, forming the core of China's low carbon baseload capacity additions.

Under Rystad Energy's analysis, natural gas power generation is expected to increase alongside renewable energy generation, from 0.3 PWh in 2022 to 0.6 PWh in 2030 and 0.8 PWh in 2040. The additional gas-fired capacity acts as a backup and dispatchable energy source in the event of a shortage of renewable power generation, enabling China to call on a stable source of energy with quick ramp-up capability. According to a speech made by Huang Weihe[20] at the International High-Level Forum on Green and Low Carbon Energy Revolution in Beijing indicated that China's gas-fired power generation is primed to reach 150 GW by 2025. This will be followed by a subsequent increase to 330 GW by 2040, nearly tripling the existing 115 GW of gas-fired capacity. This is driven by the need for more peak-shaving, driving gas demand in the power sector from 122 Bcm in 2025 to 308 Bcm by 2040, as mentioned by Huang. Huang also highlighted that the demand for gas used either as fuel or feedstock will continue to grow until 2040, before tapering off.

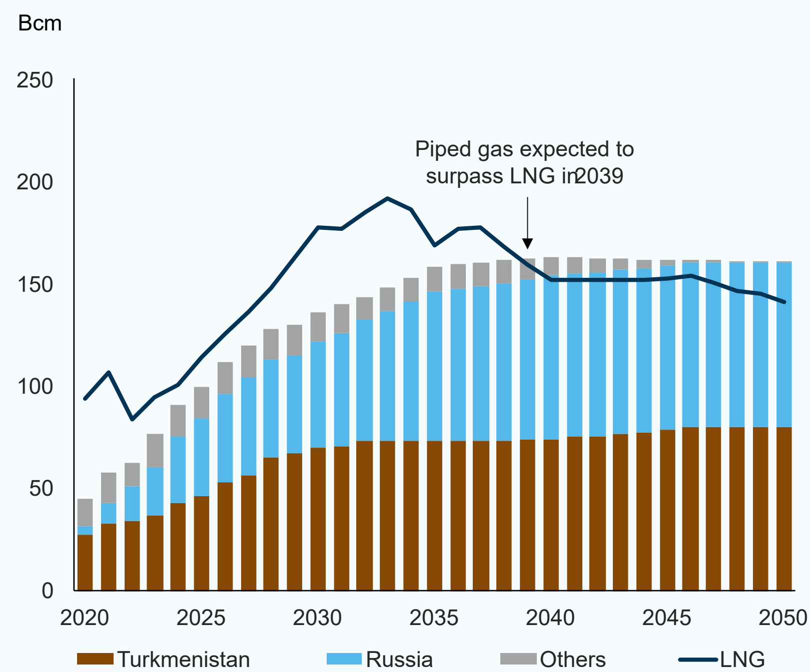
This trend means that China will have to import more gas to bridge the gap between demand and domestic production.

Figure 70: China power generation by type



Source: Rystad Energy

Figure 71: China gas imports split by LNG and piped gas countries[21]



Source: Rystad Energy

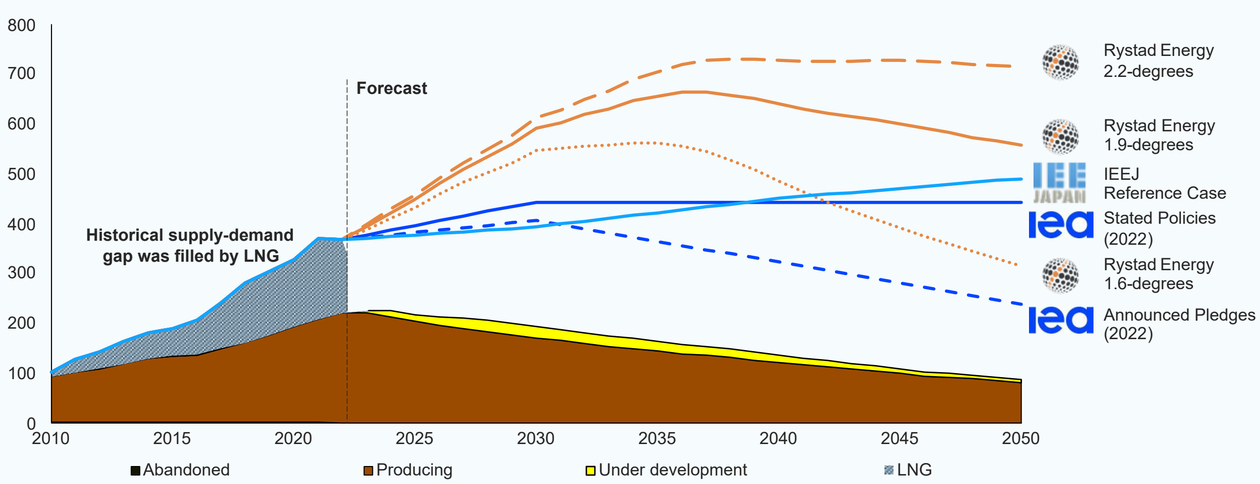
[20] *Member of the Chinese Academy of Engineering, who served as vice president of China's largest oil and gas company, PetroChina, in 2008.*

[21] *Others include Kazakhstan, Uzbekistan, and Myanmar.*

The country has regarded domestic production as the cornerstone of its gas supply mix, prioritising self-sufficiency, and is unlikely to allow imports to account for more than 50% of total supply in the future. In 2022, China consumed 367 Bcm of gas, 40%, or 146 Bcm came from imports. According to Rystad Energy's analysis, piped gas imports are expected to increase at a faster pace as China plans to expand the gas pipeline network to between 170,000 to 200,000 kilometres by 2040, from 120,000 kilometres as of June 2023. The main suppliers of piped gas to China are Russia and Turkmenistan, as developments for the Power of Siberia 2 (38 Bcm per year) and Central Asian pipeline (30 Bcm per year) are progressing quickly. Piped gas imports are expected to surpass LNG by the two next decades, as seen in the chart below.

In the domain of low carbon gases, China Southern Power Grid (CSPG) is exploring options to harvest surplus renewable generation for later use through production of hydrogen from excess renewable energy. The company has brought two pilot hydrogen power plants online in Kunming and Guangzhou. Looking at China's historical domestic gas production, LNG is required to fill up the demand gap. Across various scenarios, it is evident that China's gas imports will remain robust, as operational, and approved assets are not sufficient to meet demand. As such, LNG will be key in fulfilling remaining consumption,and this is expected to remain robust, even in decarbonisation-centric scenarios such as the IEA APS and the Rystad Energy 1.6-degree projection. China's energy landscape is undergoing significant transformation, and natural gas is expected to play a central role in ensuring grid security and firming in China's pursuit of a low carbon economy. At the same time low carbon gases could potentially provide innovative storage potential for curtailed renewable electricity in the long term.

Figure 72: China gas demand scenarios from various institutions against operational and approved production (2010 – 2050)



Source: IEA; IEE Japan; Rystad Energy

3 / Natural gas and low carbon gases in the energy transition

3 / Natural gas and low carbon gases in the energy transition

This chapter builds on the scenarios presented in the previous chapter to lay out future pathways of decarbonising the consumption of natural gas and increasing the supply of low carbon gases. A high-level gas decarbonisation framework helps to set the scene for analysing the possibilities and challenges within the 3 largest gas demand segments: power generation, buildings, and industry. Transportation is not evaluated despite its growing importance as a decarbonisation tool because of the current limited size of the market. The criticality of natural gas supply decarbonisation and the dramatic growth necessary in low carbon gas technologies goes hand in hand with addressing the large variety of possible outlooks of natural gas demand towards 2030 and beyond.

Highlights

- **Energy conservation mechanisms have largely been overlooked as a powerful tool to reduce emissions and reduce overall energy use.** Demand response, time of use pricing and combined heat and power generation are tools that would reduce the stress in the energy markets, improve efficiency and ultimately reduce the total emissions from the energy system. Energy efficiency is an important pillar in existing decarbonisation scenarios, and together with conservation measures, it can deliver real value, including but not limited to reductions in natural gas demand. These measures require targeted policy attention.

- **Gas demand will likely remain resilient in power and industry at a global level, offering unmatched flexibility as a dispatchable source in power generation, and process heat applications for high-temperature industries.** Battery energy storage systems (BESS) and gas offer different value propositions as flexible energy sources but are complementary and should not be viewed as mutually-exclusive alternatives – both will be necessary. BESS are energy-limited resources and provide their highest value when used in short-duration rapid response grid and renewables balancing dispatchment, while gas-fired power is an energy-unlimited resource (provided the fuel is available) and its most valued quality is long-duration dispatchable reserve. Simply put, gas generation enables sustained long-term stability of the power system, while batteries help to ensure sustained power quality by smoothing sudden spikes. For heat intensive processes, there are currently no cost-effective and scalable alternatives to natural gas for meeting high temperatures required in the industrial sector.

- **Renewable and low carbon gases show promising results in reducing the emissions of natural gas supply in the power, industrial, and buildings sectors to meet heating, reactant and feedstock needs, provided they are produced efficiently, sustainably, and cost-effectively, and are accessible in sufficient quantities.** With CCUS emerging as a competitive decarbonisation lever coupled with significant developments in policies to encourage the roll out of capture facilities, deindustralisation can be avoided by retrofitting existing facilities and infrastructure to be less carbon intensive. Low carbon hydrogen can supplement or replace natural gas in certain sectors and processes, although infrastructure integration challenges still exist. Biomethane, which is a renewably produced natural gas, and e-methane, which is low carbon hydrogen transformed into methane, offer a one-to-one direct substitute of natural gas, requiring no modifications to existing natural gas-related infrastructure. Biomethane is already produced and used across the world, even though its scale remains small relative to current natural gas usage. E-methane is a technology that is actively pursued by several players in the industry. All the above low carbon gas technologies require aggressive acceleration from the insufficient levels today to be in step with the transition needs.

- **Methane emissions in existing natural gas operations must continue to be aggressively reduced for gas to maximise its value as a transition fuel and remain as an efficient and sustainable product for resolving the challenges posed by the energy trilemma.** Methane is a powerful short-term greenhouse gas, with the natural gas supply chain being the source of approximately 13% of anthropogenic methane emissions. In total, the oil and gas sectors are responsible for roughly 25% of global methane emissions. Mitigating methane emissions from the natural gas value chain provides the oil and gas industry with an opportunity to stay relevant in an increasingly decarbonised world, and thus, reducing the likelihood of stranded gas assets and increasing the quantities of sellable volumes of gas.

Gas decarbonisation framework

Table 5: Gas decarbonisation framework

	Power generation	*Industry*	*Buildings*
Conservation & efficiency *Use less*	Demand response	Optimisation of processes and CHP	Insulation
Low carbon gases *Swap and Blend*	CH4 Fossil → H_2 Swap some or all natural gas with low carbon gases such as hydrogen or biomethane		
Low carbon electrons *Swap*	Renewable power generation	Electrification of processes	Electrification
Carbon capture *Clean*	CCS in power	CCS of industrial emissions	Limited technological feasibility

Source: Rystad Energy

This section explores the future of gas in the energy transition and its associated challenges and opportunities. It leverages the 'Gas decarbonisation framework' (Table 5) to establish a baseline for the role of gas in the energy transition, and to outline major decarbonisation pathways for the three most important gas demand segments through four distinct strategies. Gas offers diverse opportunities and attributes that contribute significantly to the global energy system, particularly in the power, industrial, and building (residential and commercial) sectors which were responsible for around 85% of global gas demand in 2022. Gas is an important part of the power mix and offers great flexibility in power generation. In the industrial sector, gas is used as a reactant, feedstock and for high-temperature heating.

Many regions of the world depend on piped gas distribution networks to run utilities and provide heat in homes, schools, and hospitals. Notably, even though it is not included in the above table, gas has been a growing input into the transportation sector, where LNG has been helping to displace oil and reduce emissions associated with long-haul transport and shipping.

The following four strategies can be deployed to reduce environmental impact and decarbonise natural gas in the power, buildings, and industrial sectors: capturing the low-hanging fruit of reducing consumption with pro-active conservation programs, effective demand-response, and efficiency improvements in processes, insulation, or re-use of excess heat from processes; electrification through decarbonised electrons; gradually replacing natural gas with low carbon and green gases; continued use of natural gas with carbon capture facilities.

Energy and gas demand conservation considerations

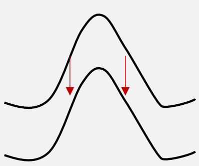
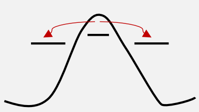
Amid the energy transition and shifting supply dynamics, energy conservation has been largely overlooked as a powerful tool for emissions reduction by reducing overall energy use. It involves using energy more efficiently and thoughtfully through demand-side management, and bolstering supply through optimisation. These actions improve resource availability, shore up energy security, and stabilise the energy landscape. Measures fall into 'preventive' and 'reactive' categories, proactively managing consumption and responding during periods of resource constraints or grid stress.

Demand-side energy conservation measures are actions and strategies taken to reduce energy consumption by the consumer or end-user. These measures focus on optimising energy use, increasing efficiency, and minimising waste. There are many examples of demand-side energy conservation measures, four of which warrant closer review.

Demand response programmes: Demand response programmes are classified as 'reactive' measures. These programmes aim to reduce electricity consumption during peak demand periods by encouraging and incentivising consumers to adjust their energy usage. This can be done through various strategies, such as shifting non-essential activities off-peak hours or temporarily reducing the operation of certain appliances or equipment (for instance, charging electrical vehicles at periods with lower stress on the grid). Industrial players can bid into demand response auctions where they would be paid for the capacity, they offer to reduce the demand to reduce the stress in periods of high demand. This alleviates strain on the energy system, enhances grid stability, and minimises the need for additional power generation, ultimately contributing to energy conservation and more efficient energy use.

Time of use (TOU) pricing: Consumers are charged varying electricity rates based on the time of day, promoting energy conservation during peak hours, and encouraging usage during off-peak times. TOU provides consumers with options to save by conserving and shifting energy use to cheaper times of the day. Coupled with smart meters and digitalisation technologies, TOU can both reduce the strain on the energy system and reduce the energy cost for the consumers. Research by "Energy Saving Trust" suggest that the load during peak demand would be reduced by 5%-10% with implementation of TOU. Ontario, Canada has been one of the first jurisdictions in the world to roll out smart meters and implement robust conservation and TOU programs, and it estimates that conservation will have saved it over 30TWh of electricity.

Table 6: Energy conservation demand management measures

Demand measure		Aim	Impact on peak demand	Impact on energy demand
	• Energy efficient appliances • Cogeneration/ CHP • Demand response	Reduce the overall energy demand	Decrease	Decrease
	• Demand response • Ecosystem integration	Shift peak demand to off -peak hours (load levelling)	Decrease	Unchanged

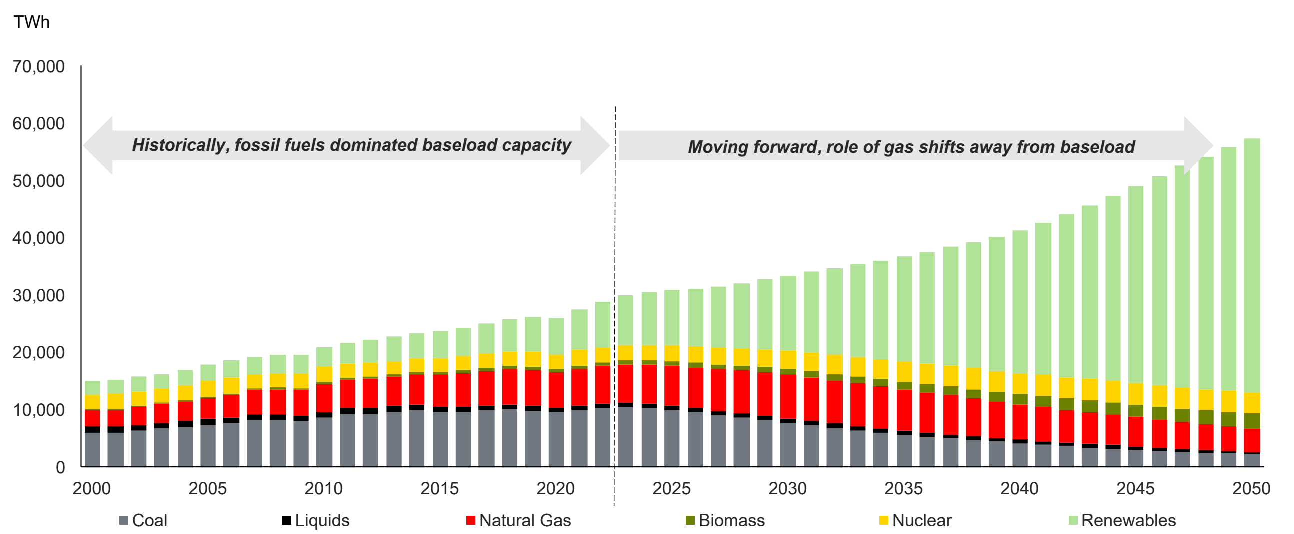
Source: Rystad Energy

Combined heat and power (CHP)/cogeneration: Simultaneous production of electricity and useful heat during gas-fired power production. The goal is to enhance energy efficiency, especially by repurposing waste heat from power generation and industrial processes for heating buildings, industrial applications, and even cooling needs. Cogeneration plants can achieve impressive energy efficiency levels of around 90%, optimising resource utilisation and minimising waste. These units are much more efficient than conventional open and combined cycle turbines where the energy efficiency typically is in the range of 40% – 60%, depending on the age and quality of the turbine.

In the EU, the Renewable Energy Directive within the Fit- for-55 package includes provisions that support the use of high-efficiency cogeneration. It acknowledges cogeneration's role in enhancing overall energy production efficiency, decreasing emissions, and aiding the integration of renewable energy sources.

Gas as a flexible and dispatchable source of power

Figure 73: Power generation by primary energy source[22]

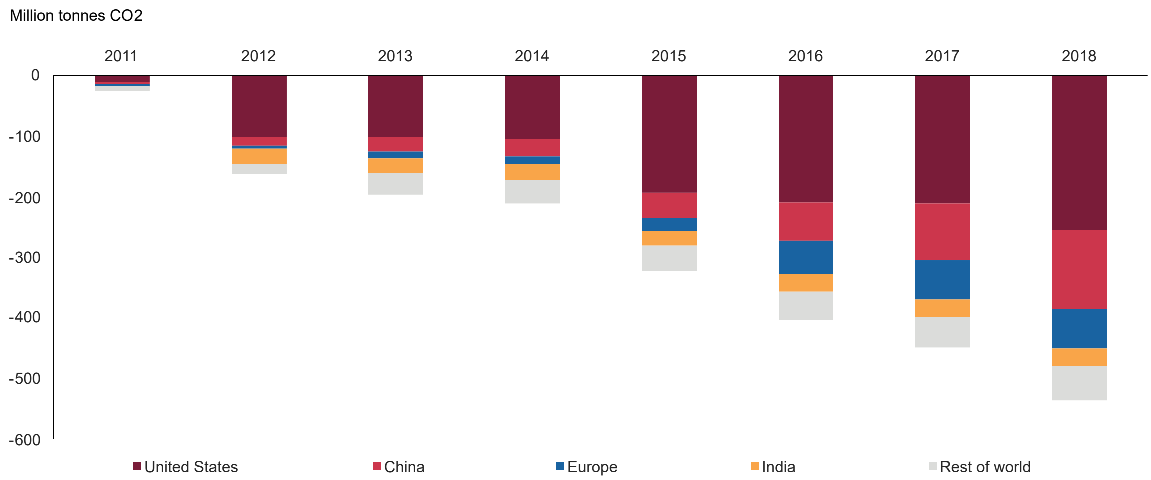


Source: Rystad Energy

Historically, the power sector has been dominated by fossil fuels, with coal and gas comprising around 40% and 22% of the global power mix, respectively. These sources mainly serve as baseload, intermediate and/or peaking power to provide year-round stability to global power grids. Power generation accounted for 34% of total gas demand in 2022. As the energy transition progresses, in many parts of the world renewables are likely to displace fossil fuels as the dominant power generation source. This is exemplified by Rystad Energy's 1.9-degree scenario (Figure 73) in which the share of coal declines to 4%, while the share of renewables scales to around 77% by 2050. In turn, natural gas shifts from being a baseload provider to becoming a flexible, dispatchable capacity resource to balance the electricity grid in times of renewables intermittency. This balancing is necessary for maintaining grid stability and delivering reliable, consistent, and uninterrupted, power supply. The growth in share of renewables in the generation mix is directly corelated with a growing need for flexible balancing capacity that gas provides. As such, even with high renewable capacity additions, additional gas-fired generation capacity must likely be developed to maintain energy security in grids.

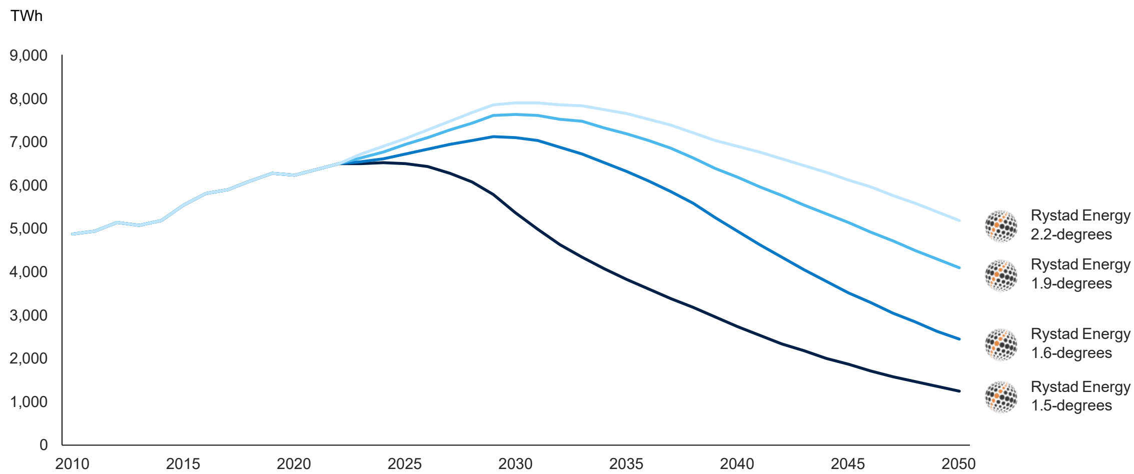
[22] *Rystad Energy's 1.9-degree scenario has been used as an example.*

Figure 74: CO2 savings from coal-to-gas switching in selected regions compared with 2010



Source: IEA – The Role of Gas in Today's Energy Transitions, 2019

Figure 75: Power generation by natural gas in varying degree-scenarios



Source: Rystad Energy

The role of gas as a flexible, dispatchable source varies depending on the pace of energy transition in different countries and regions. Emerging economies, such as those in Africa where general energy poverty is still high and Asia where coal plants still dominate, consider gas as a stable and sustainable alternative to energise economies and lower the carbon intensity of the grid, before moving towards increasing renewable energy adoption and leveraging the dispatchable characteristics of gas. In Africa, where electricity access is scarce, even the areas with the best access on the continent have weak and unstable grids, with frequent outages. These grids would require additional reinforcement and flexible capacity to integrate large-scale renewables without risking a collapse (further details can be found in the IGU "Gas for Africa Report").

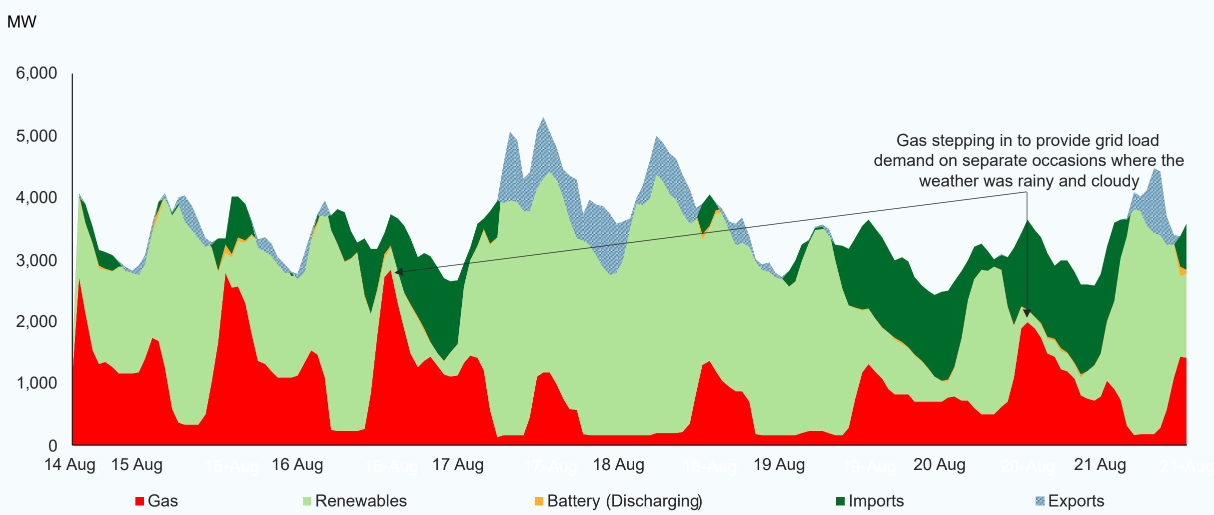
With reference to Figure 74, positive effects of coal-to-gas switching are already evident in countries such as the United States and China, where coal-to-gas switching has helped prevent faster growth in emissions since 2010, avoiding 536 million tonnes of CO2 emissions by 2018. The largest emissions reduction from coal-to-gas switching has occurred in the United States, where the rise of shale gas (and associated gas) reduced local natural gas prices, introduced abundant supply, and allowed large-scale switching from coal to gas in the power sector. Between 2010 and 2018, this resulted in emissions declining by a fifth to 280 million tonnes of CO2.

Across Rystad Energy's degree scenarios (Figure 75), the significance of natural gas in the power sector remains pronounced, even in high renewable adoption scenarios such as the 1.6 and 1.5-degree scenarios. While all scenarios project a decrease in natural gas-fired power generation by 2050, the pace and extent of the decline differs among scenarios. In the 1.6, 1.9 and 2.2-degree scenarios, gas-fired power generation is expected to increase in the short to medium term, driven by the increased pace of coal-to-gas switching in emerging economies in Asia. In regions such as Africa, gas becomes vital in addressing energy availability. In the long run, the decline in gas-fired power generation reflects the pace of adoption of renewables and battery energy storage systems (BESS), which is the fastest under the 1.5-degree scenario. However, long-term gas-fired generation remains necessary for dispatchable energy and grid stability, due to the energy-limited nature of batteries, and geography-limited larger capacity forms of storage, such as pumped hydro.

The above discussion does not consider that natural gas-fired plants can be decarbonised with the use of new low carbon gases and/or retrofitting with carbon capture technology. This approach would allow gas-fired plants to operate into the future as low-emission sources of firm capacity, while also enabling existing infrastructure to be reused. Biomethane is a one for one renewable substitute for natural gas, while blending low carbon hydrogen and ammonia for co-firing with natural gas is another viable alternative.

Case study: Future role of dispatchable sources in renewable power grids

Figure 76: One-week comparison of South Australia's power supply trend, energy in megawatts broken down by resource in hourly increments (2023)

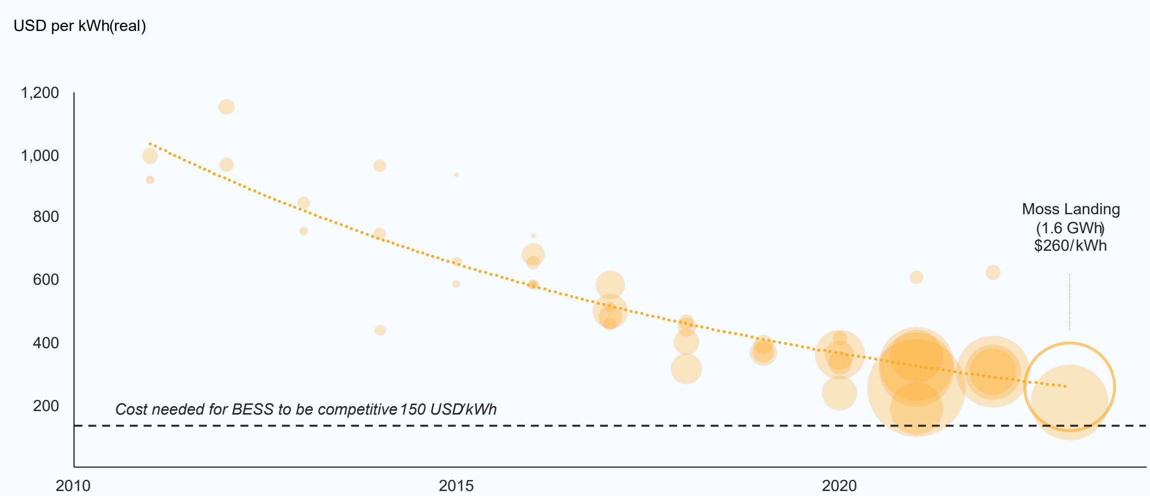


Source: Open National Electricity Market; Rystad Energy

South Australia is renowned for having one of the world's highest renewable-penetrated grids, with wind and solar accounting for 70% of the capacity needed to fulfil local demand. As of 31 October 2022, South Australia had 221 MW of existing battery and virtual power plant (VPP) storage capacity with plans to add an additional 4,045 MW of storage capacity. Being completed in 2023 is the Torrens Island Grid Scale battery energy storage system, which has 250 MW capacity and is currently the second largest operational battery in Australia. The state's grid frequently experiences situations in which wind and solar generation reaches and surpasses 100% of demand. The surplus energy is exported to Victoria via transmission grids and stored in the Hornsdale Power Reserve battery, providing important short-term backup to the power grid. However, even in the renewables-governed power mix of Victoria, gas-fired power plants have been consistently operational and essential in avoiding instability. Figure 76 demonstrates how gas has effectively bolstered generation during adverse weather conditions in South Australia. Between 20th and 21st August 2023, renewable generation was insufficient to meet daily consumption. To compensate for that, imports and gas resources were ramped up to meet demand. This displays the importance of dispatchability in energy sources for grids to operate, tapping on such sources in times of high system load and limited renewable generation. However, the share of power met by dispatchable sources depends on regional renewable characteristics, and installed capacity. Regions lacking sunny or windy conditions will experience longer, more severe, and frequent periods where dispatchable sources intervene as the grid-firming mechanism. Batteries will help offset some of the call on dispatchable sources (e.g., gas), but battery economics will deteriorate greatly if the system is dimensioned to fully accommodate all possible weather scenarios, further discussed in the following case study.

Case study: The use cases for BESS systems

Figure 77: Capital cost for selected battery storage projects



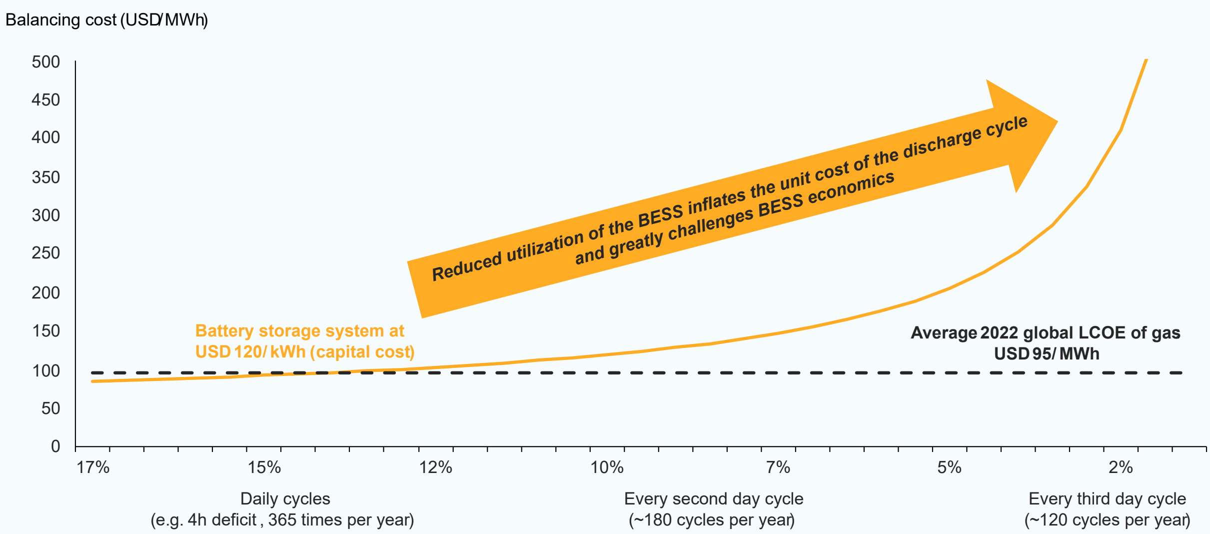
Source: Rystad Energy

Thanks to their precision and rapid reaction time, battery energy storage systems (BESS) are a superbly universal tool for electric grid reliability services, as well as for "firming" non-hydro renewable energy integration and providing critical short-term ancillary services like regulation and voltage control to the power grid. They serve as backup resources by storing surplus energy during high-generation periods and discharging when renewable output is low (or when demand spikes), providing a more even power supply. The optimal business case, or the sweet spot, in which BESS value is maximised is in the short duration reliability and firming operations, as both physical limitations of energy storage capacity and the economics of less frequent discharges make it less feasible for batteries to deliver in longer duration balancing zones.

BESS capital costs have significantly decreased over the past decade, declining from $1,000 USD/kWh in 2010 to $260 USD/kWh for recent 2022 projects (Figure 77). While expectations of further price declines remain, these could be countered by inflation of battery project cost drivers such as materials and equipment expenses, potentially increasing BESS project capital costs by 15% to 40%. In addition, BNEF reports rising battery costs of 7% from 2021 to 2022. Thus, to match gas generation competitiveness, Rystad Energy suggests that BESS capital costs would need to approach $150 USD/kWh, assuming a $5 USD/MMBtu gas price and a $100 USD/tonne CO2 carbon price.

Figure 78 illustrates BESS as advantageous over gas for storage durations of up to four hours and with daily cycles. Yet, with expanding storage duration, the marginal utilisation of the system falls and results in an increasing LCOS, which surpasses gas generation's LCOE. As such, this highlights an important financial consideration in energy system planning. As the energy landscape transitions towards more renewable sources, costs associated with scaling up energy storage can be significant due to the linear relationship between storage capacity and investment – with a higher storage need, the capital cost of the BESS system would increase. In contrast, gas-fired generation can provide dispatchable power without a one-to-one correlation with storage capacity. This highlights the advantage of gas (both natural gas and other low carbon gases) from a cost perspective, accentuating the case for gas.

Figure 78: LCOS of batteries and LCOE of open-cycled gas turbine[23]



Source: Rystad Energy

[23] *Assuming a four-hour battery system with 250 MW of capacity, 13 USD/MWh charging cost, capital costs of 120 USD/kWh and 250 MW open-cycle gas turbine. The figure above assumes capital costs of BESS to continue declining and illustrates a case example to show how low charging and battery capital costs needs to be for it to be competitive. For reference the average European power price between 2018 and 2020 has been between 20 and 80 EURO/MWh, significantly lower than the 2030 forecasted charging cost in the analysis above.*

Capacity assurance mechanisms demanded for energy stability and reliable power grids

Capacity mechanisms, akin to insurance for grid stability, are designed to ensure adequate supply being available to meet maximum demand peaks (if demand and supply are not perfectly balanced every hour of every day, the electricity system can collapse into lengthy blackouts). Capacity mechanisms compensate electricity generators for being available to be called on in reserve even if they are not always operating. This capacity compensation is necessary to secure investment in and maintenance of capacity beyond what is needed for baseload and normal operations. The nature of reserve capacity is that it is operating less than baseload, its operational revenue alone does not provide for a commercial business case when capacity is not priced by the market. The emergence of capacity markets in some jurisdictions has been a way to address that and ensure sufficient reserve capacity.

Capacity planning is also a long-term electricity system reliability requirement to address the long lead time from capital investments to energy supply availability when new demand emerges. As was discussed earlier in the energy trilemma section, a high voltage power transmission line can take as long as a decade to be built, and as such this infrastructure should be planned ahead of anticipated demand growth to avoid shortages.

In North America, a robust cross-jurisdiction authority was created to enforce reliability and reserve capacity planning after the 2003 Northeastern grid across parts of Canada and the United States collapsed into a prolonged blackout, due to a combination of key monitoring systems going offline, generators not responding as anticipated, and an overloaded line short-circuit, with insufficient reserve generation. The newly created North American Electric Reliability Corporation (NERC) implemented strict rules imposing reserve requirements to avoid similar risks in the future.

In Europe, capacity margins are tightening. Many older generation facilities, especially aging coal and nuclear plants are nearing the end of their operational lives are being decommissioned due to environmental protection policies. Additionally, these markets are witnessing a sharp rise in the penetration of variable renewable power sources. As the generation mix evolves, system operators are evaluating strategies to ensure security and capacity margins. Some systems may adopt storage systems and demand-side responses, while others could rely on flexible, dispatchable sources such as gas fired capacity. However, in many jurisdictions, sufficient new conventional power plants (especially gas-fired) are not being built. This is due to challenges such as low power prices, utilisation, and the inability to obtain financing.

In places like Africa, where electricity is scarce, capacity reserve is today viewed as a luxury and power quality problems and outages are frequent. For these markets to have the ability to increase renewables-driven electrification, capacity planning and investments including natural gas generation will be pivotal for the energy transition to succeed. Nigeria's power grid, for example, has suffered over 200 partial or total collapses in the last decade, and there is a direct negative impact from each of these events on the economy.

Capacity mechanisms have been established in many developed economies to ensure that power systems are able to cope with the changing nature of generation and demand. Markets are increasingly looking to new gas-fired and nuclear plants, particularly as policymakers turn away from coal-fired plants in search of less carbon-intensive generation. In Europe for example, there are two broad types of capacity mechanisms: 'targeted' and 'market-wide'. 'Targeted' mechanisms solely support the extra capacity required by the market, while 'market-wide' supports all participants (existing and incumbents) as required to meet reliability standards. Similar activities and mechanisms are being rolled out in the United States. Table 7 on page 71 shows the different approaches to capacity mechanisms used and proposed in various countries in Europe.

Table 7: Capacity mechanism types and European examples

Type of capacity mechanism		Description	Where used or planned
Targeted	Strategic reserve	• A certain amount of capacity is held outside the market to be called upon in emergency situations • Volume based	Sweden Germany Finland
Targeted	Tenders for new capacity	• Support is granted to new investment projects to bring forward identified capacity required. May run in the market or be supported by a power purchase agreement • Volume based	France
Targeted	Targeted capacity payments	• Administrative payments are made to a subset of capacity in the market • Price based	Spain Portugal
Market -wide	Central buyer	• The total amount of required capacity is set centrally , and procured by a central buyer through a central bidding process in which potential capacity providers compete so that the market determines the price • Volume based	Italy Greece Ireland United Kingdom
Market -wide	Market -wide capacity payments	• An administrative payment is available to all market participants • Price based	Ireland Poland Belgium

Source: Rystad Energy; European Commission; Single Electricity Market Operator

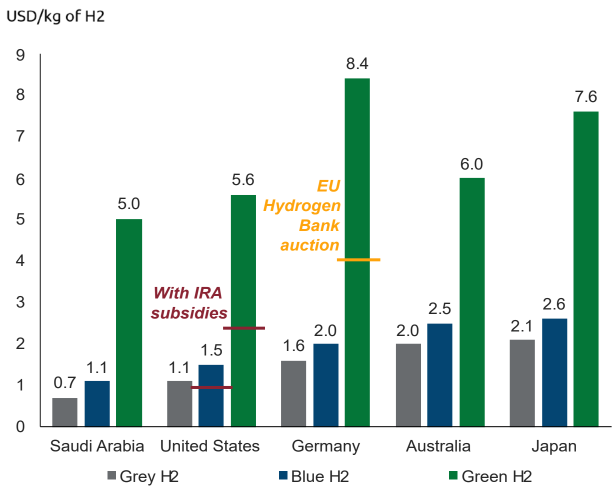
Possibilities with renewable and low carbon gases

This sub-chapter explores the pathways presented by low carbon and green gases. These include natural gas with CCUS, low carbon hydrogen (including its carriers, blue and green ammonia), biomethane and e-methane, which can either fully substitute natural gas directly or be blended with it to reduce emissions in various sectors. These gases offer a viable, direct replacement option (in many applications) as an alternative source to meet heating, reactant and feedstock needs, provided they are accessible in sufficient quantities and are cost-effective.

Though cost remains a key challenge for green hydrogen today (Figure 79 on page 72), scaling and growth in deployment are expected to bring significant cost reductions, as illustrated in Figure 79. Presently, green hydrogen is around three times more costly than blue hydrogen in the highlighted countries in the figure. The main driver of the high price of green hydrogen production is usually electricity cost, which could comprise more than 70% of cost for some locations. As such, access to low-cost renewable electricity is a primary way to make green hydrogen more competitive, in addition to cost improvements on the capital costs of electrolysers. Under Rystad Energy's analysis, the cost of green hydrogen is likely to become more competitive in the future, with prices expected to drop down to, and in some cases, below 2 USD/kgH2.

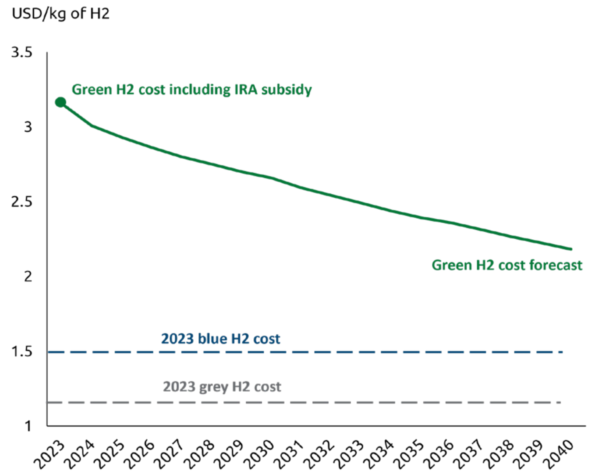
Governments globally have acknowledged the cost challenge of hydrogen and are acting. In the United States, one of the largest global hydrogen subsidies have been authorised via a tax credit for hydrogen producers worth up to 3 USD per kilogramme. Even with the subsidy, green hydrogen is likely to remain the costliest option, while blue hydrogen may potentially be on par or become cheaper than grey hydrogen. Additionally, on August 30th, 2023, the European Commission introduced the European Hydrogen Bank auction, offering a fixed premium of 4.5 Euros per kilogramme of renewable hydrogen. With the subsidy, the LCOH (levelised cost of hydrogen) of green hydrogen in Germany approximately halves. However, the cost of green hydrogen is still a far cry from blue or grey hydrogen. There is still a long trajectory required in the green hydrogen space for cost to be significantly reduced to meet its blue counterpart, and eventually

Figure 79: Levelised cost of hydrogen[24] for selected countries (2023)[25]



Source: Rystad Energy

Figure 80: Production cost forecast of green hydrogen in the United States[26]



Source: Rystad Energy

as carbon prices rise and renewable competitiveness grows, grey hydrogen.

The costs presented in Figure 80 is the cost of delivering hydrogen to the local market. Additional costs would incur to export these volumes and profit margins demanded by the developers would come in addition. The end-consumers of hydrogen are likely to see higher commodity prices with cost additions also related to the infrastructure export, import and distribution infrastructure.

As of August 2023, there is 3.2 million tonnes of operational low carbon hydrogen production capacity globally, with the majority of that capacity coming via blue hydrogen. In comparison to the 91 million tonnes of hydrogen consumed in 2022, existing operational clean hydrogen can only cater to 3.5% of global hydrogen demand and is an order of magnitude short of the projected global demand for hydrogen in the energy transition. For example, the EU target alone is 20 million tonnes by 2030. Considering today's project pipeline, more than 800 kilo-tonnes of blue and green hydrogen capacity has reached FID, these volumes will lift the total operational production in 2030 to almost 4.5 million tonnes per year (Figure 81 on page 73). Most low carbon hydrogen projects are located in China, Saudi Arabia, and the United States of which approximately 96% involve green hydrogen. The pre-FID project pipeline currently stands at almost 44 million tonnes of blue and green hydrogen by 2030 (Figure 82). One-third of the pre-FID pipeline is blue hydrogen, which signals a call for further natural gas demand in the blue hydrogen domain. Given the substantial size of the pre-FID pipeline and the gradual pace of FID decisions, it is evident that the progress of low carbon hydrogen projects has been relatively slow. This speaks to the challenge of scale, where production and implementation of low carbon hydrogen needs to rapidly grow to sufficiently replace existing processes and resources. In addition to the supply growth requirement, a separate parallel scaling effort would be required to develop the infrastructure to deliver it and technologies to adapt end use if hydrogen is to be used as direct fuel.

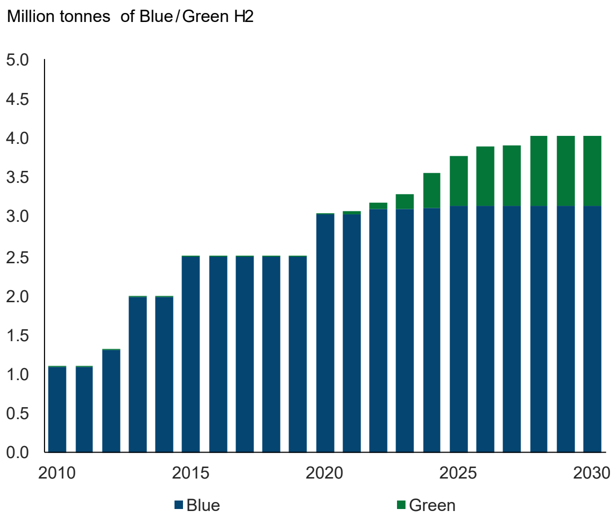
There are several means of transporting hydrogen via pipelines. Building new hydrogen pipelines is a method that has already been adopted in North

[24] Grey H2 uses natural gas as feedstock, while blue H2 is the same except that all CO2 emitted is captured. In contrast, green H2 is generated via electrolysis of water.

[25] Results and calculations are based on Rystad Energy assumptions extracted from the Rystad Energy Dynamix cost dashboards, with the capacity factors used ranging from 12% to 30%, CCS costs (transport and storage) being 12 USD/tonne of CO2, and feedstock costs used ranging from 30 USD/ MWh to 120 USD/MWh.

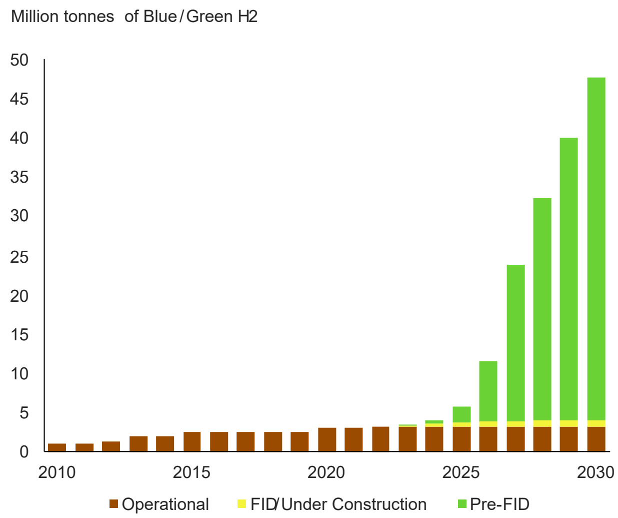
[26] Cost reduction of green H2 is dependent on location of production (i.e., renewable conditions and relevant renewable power source), size of plant and technology and cost development of electrolyser. Lower prices can be achieved in favourable markets. The Henry Hub 2022 average natural gas price was approximately 22 USD per MWh, compared to the green hydrogen price at 95 USD per MWh in 2023.

Figure 81: Clean hydrogen cumulative capacity post-FID projects only (2010 – 2030)



Source: Rystad Energy

Figure 82: Clean hydrogen cumulative capacity by status, including pre-FID projects (2010 – 2030



Source: Rystad Energy

America (2,700 kilometres) and Europe (1,700 kilometres). However, establishing new pipelines can cost up to four times more than repurposing existing ones, according to Rystad Energy's research. Extensive research is ongoing for pipeline retrofitting, particularly in areas with well-developed natural gas pipeline networks. Germany serves as a notable example, only requiring 30 billion euros to repurpose its gas grid of more than 550,000 kilometres that has been funded by around 300 billion euros in the past. This is the result of a study on the steel pipelines in Germany's gas grid, which concluded that the pipelines are hydrogen ready. Several companies are also looking to repurpose their pipelines, with Snam having already modified its pipeline system – the largest natural gas transmission network in Europe of 42,000 kilometres of pipelines – and has announced them to be 70% hydrogen-ready with no or limited reductions on max operating pressure (up to 99% with more substantial compression revisions).

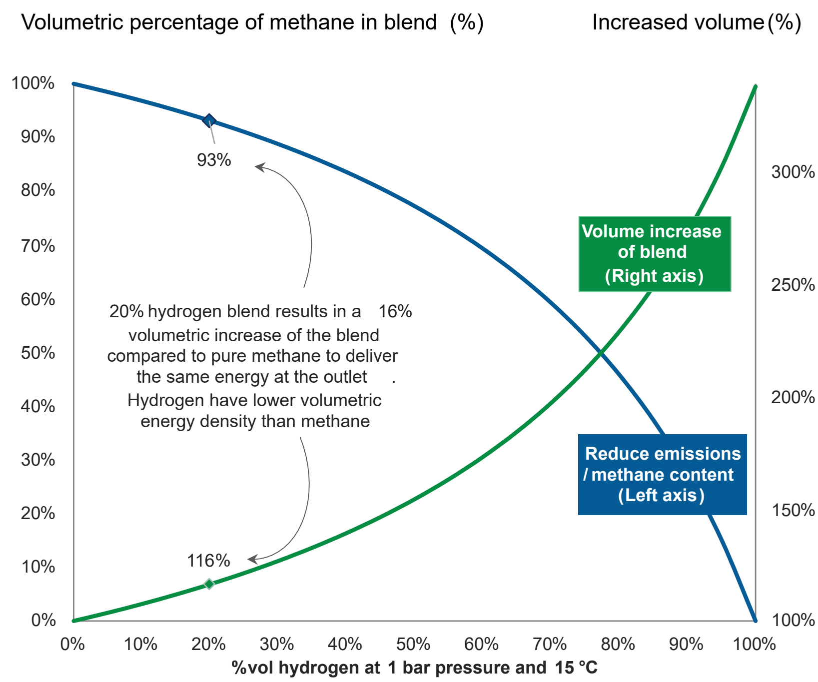
While the natural gas infrastructure is valuable as an already existing backbone for integration of the new low carbon gaseous energy, hydrogen transport would require existing natural gas infrastructure to be repurposed. This is an area that requires continued work from the industrial and classification domains, as the business case and level of hydrogen in the gas distribution network could call for retrofitting and improvements to be made (coating, leak detection, etc.), depending on the jurisdiction and state of infrastructure.

Blending of hydrogen with natural gas is emerging as a middle-ground solution to scale hydrogen use while waiting for the readiness of supply and purpose-built infrastructure in the mid- and downstream segments. Blending hydrogen with natural gas is a potential means of decarbonising natural gas, while utilising existing infrastructure without large modifications. Current pilot projects suggest 20% blending to be achievable in most cases without altering infrastructure. However, as hydrogen has considerably lower energy density than natural gas, a volumetric blend of 20% hydrogen in natural gas is estimated to reduce emissions by around 7% while delivering a fixed amount of energy output for the end user. Figure 83 on page 74 shows the relation between the reduction in methane content and hence emissions, and the increase in total volume of the blended gas.

The technical challenges of higher share of blending need to be addressed. Firstly, when injected into steel pipes, hydrogen can accelerate pipeline steel degradation and cause embrittlement, necessitating the installation of coatings for protection, albeit at an increased refurbishment cost. Additionally, hydrogen transport through former natural gas pipelines may require additional compressors, approximately three times the compression power compared to natural gas, owing to hydrogen's lower energy density.

To put things into perspective, Rystad Energy conducted an analysis of 2022 sustained gas demand towards 2030 in hydrogen equivalent terms against the existing clean hydrogen project pipeline, both including and excluding pre-FID volumes, alongside the REPowerEU target of 20 million tonnes of renewable hydrogen by 2030 (Figure 84). Operational and FID clean hydrogen projects could only fulfil 0.3% of 2022 natural gas demand in 2030, while the REPowerEU target would fulfil 1.7% of existing gas demand. Even with the inclusion of pre-FID volumes, a meagre 4.1%. To fully replace natural gas by 2030, as projected in the 1.5-degree and 1.9-degree scenarios, the hydrogen projects would need to scale up by 20 times and by more than 28 times respectively, similarly the capacity needed to meet 2022 demand would need to increase by more than 20. This highlights the significant challenge in scaling low carbon hydrogen production and while this analysis is a theoretical illustration to emphasise on insufficient scale, hydrogen is unable to replace gas on a one-to-one basis in all regions and sectors. Although hydrogen offers promising decarbonisation routes for diverse sectors, substantial efforts are required in terms of government policies and research and development to facilitate its scalability and cost-effectiveness and put it on a par with natural gas.

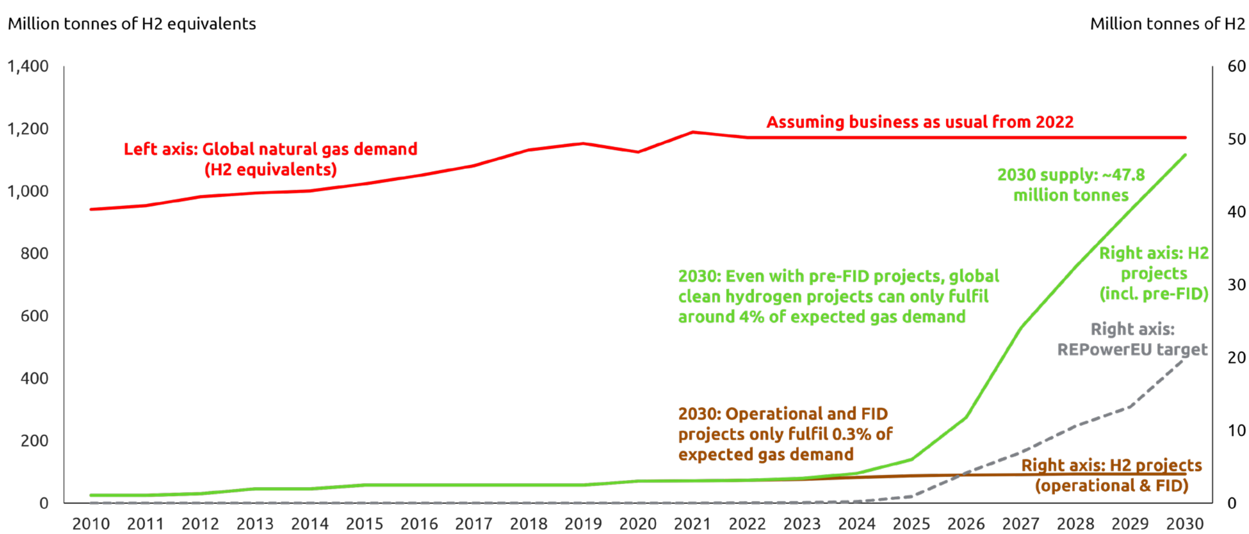
Figure 83: Volumetric methane content and corresponding volume of blended substance



Source: Rystad Energy

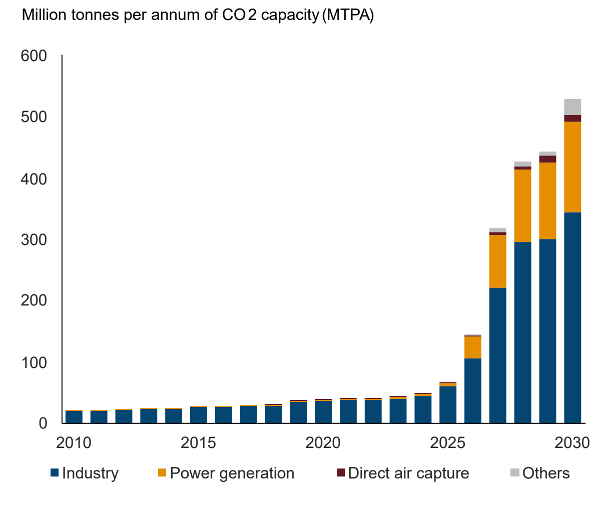
Other low carbon gases such as biomethane and e-methane offer additional decarbonisation options. Their main value proposition is their capability to substitute natural gas on a one-to-one basis, enabling the utilisation of existing infrastructure across the power generation, industrial and building sectors. Biomethane is a mature commercial technology, which

Figure 84: Cumulative blue and green hydrogen capacity (right axis) against natural gas demand expressed in hydrogen equivalent (left axis)



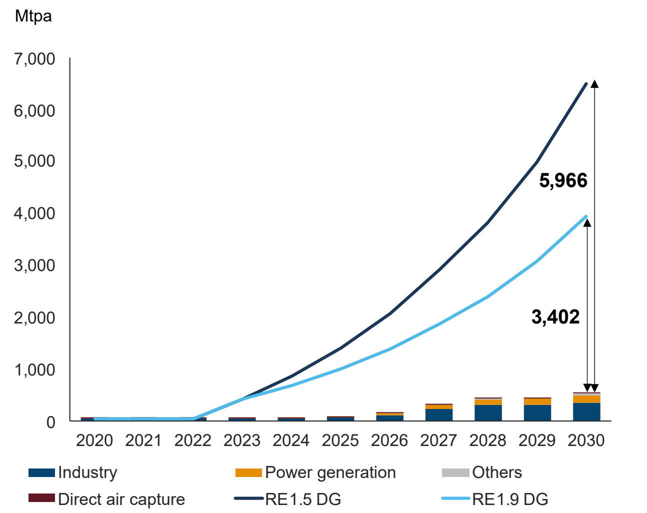
Source: Rystad Energy

Figure 85: CCUS capture projects pipeline (Operational, FID, pre-FID)[27]



Source: Rystad Energy

Figure 86: CCUS capture projects pipeline against expected CCUS capacity across various scenarios



Source: Rystad Energy

has been in extensive use across several markets, while e-methane is more nascent, and commercialisation is being actively pursued. In response to the energy crisis in 2022, REPowerEU has already triggered incremental traction and positioned European biomethane production for 35 Bcm by 2030, from around 4 Bcm in 2022. Globally, estimated biomethane production stood at around 7 Bcm in 2022, catering to around 0.2% of global gas demand that year, illustrating the need to accelerate development and grow scale aggressively. As for e-methane, developments are still in early stages, with industrial players such as Santos, Tokyo Gas, Osaka Gas, Toho Gas, and Mitsubishi Corporation rolling out demonstration projects to test the technology. If breakthroughs to reduce costs can be achieved, e-methane could prove to be a major technology for decarbonising the natural gas supply. Additional details on low carbon gases and state of supply are discussed in Chapter 1.

Carbon Capture, Utilization and Storage, or CCUS is another key decarbonisation tool and a crucial technology for achieving energy transition goals across all scenarios. The scale of adoption and technology development must grow significantly from current levels as CCUS is an essential component of the decarbonised natural gas (and energy) mix, that is embedded as key assumptions in the decarbonisation scenarios. Natural gas with CCS is a very attractive way of decarbonising consumption where there are few alternatives, such as cement, steel, glass, hydrogen, refining and gas processing.

So far (September 2023), the deployment of CCUS has had slow progress but projects are quickly emerging. An important facilitator for the increased adoption of CCUS is policy support, either through investment incentives or tax credits. Moving forward, total capture capacity (operational, FID and pre-FID) will grow from 40 MTPA in 2022 to 528 MTPA by 2030 (Figure 85). This is largely driven by the industrial sector, which is expected to account for 65% of CCUS capacity by 2030. CCUS projects in the power sector is expected to increase from 1.6 MTPA in 2022 to 146.5 MTPA in 2030, driven by coal and gas-fired generation projects, with 78.7 MTPA and 70.9 MTPA of capture capacity being developed and planned, respectively.

The effects of government support and commitment have been seen in the recent years and encouraged developers to accelerate their efforts in CCUS developments. However, according to Rystad Energy's analysis, CCUS will need to scale up by another 3,402 MTPA and 5,966 MTPA to be aligned with decarbonisation efforts in the 1.9-degree and 1.5-degree scenarios, respectively (Figure 86). This calls for greater private investments, regulatory support, and partnerships across industrial hubs to overcome challenges of cost, scale, and regulations.

[27] *Includes operational, FID, and announced projects.*

Reutilising natural gas-fired power generation infrastructure for low carbon gases

One of the main consumers of natural gas is the power sector and gas turbines currently play an important role in the global energy mix providing reliable electricity, without creating air pollution and at about half of the emissions of coal power generation (Table 3). Gas-fired power generation are cheaper and faster to build than coal-fired generation. Natural gas has been instrumental in lowering electricity emissions by replacing coal and liquid-fired power plants (see Figure 86).

Gas turbines also have a notable advantage in their ability to operate on hydrogen. This includes both new gas turbines and units already in operation which can be retrofitted to operate on high H2 fuel content. For many years, several large turbine manufacturers such as Siemens and GE have operated gas turbines that can handle varying hydrogen content. In the cases of burning a hydrogen and natural gas blend, the most used turbine technologies are the later generations of the Dry Low Emission (DLE) burner design, which can handle hydrogen contents of more than 75%.

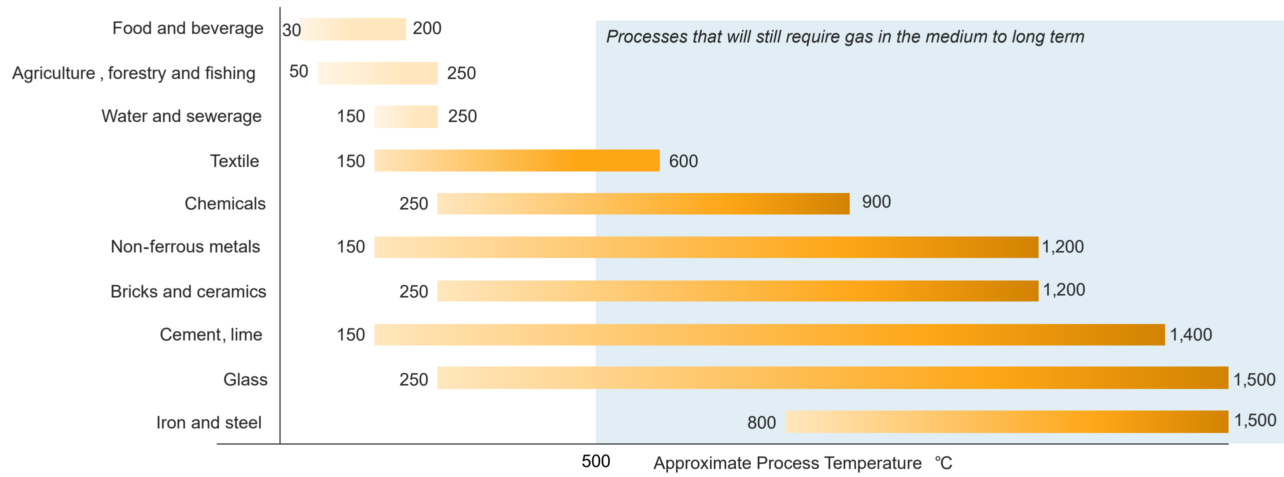
The need to upgrade existing turbines depends on the hydrogen content in the targeted fuel. Low amounts of hydrogen blended with natural gas is feasible for most applications to decarbonise the gas stream. Converting to higher and 100% hydrogen content, however, would potentially entail significant changes including numerous components in the gas turbine system. In some cases, the systems would have to be completely updated and upgraded to allow for this. The viability of converting existing gas turbines must be evaluated based on specific turbine design. Furthermore, the use of gas turbines operating on fuels containing hydrogen is often seen at industrial sites where hydrogen is available as off-gases from other industrial processes. Currently the long-haul transportation of hydrogen either as a liquid or through a carrier is far from commercial and these power generation methods are dependent on locally supplied or piped imports of hydrogen.

In January 2023, GE and IHI signed a Memorandum of Understanding (MoU) to develop gas turbines that can operate on 100% ammonia. IHI Corporation is a heavy industry manufacturer in Japan and is aiming to develop ammonia combustion technologies in collaboration with GE to decarbonise heavy duty gas turbines associated with its operations. The two companies have committed to define a technology roadmap to develop gas turbine technology that can eventually make two of GE's existing gas turbines able to run on 100% ammonia. In addition, other large gas turbine players such as MAN are looking to develop gas turbines that can operate on ammonia for heavy industries such as steel production. MAN has also expressed an interest in developing these further for use by utilities. With these gas turbines technologies reaching commerciality, retrofitting gas turbine to run on ammonia is expected to be a viable way of decarbonising gas-fired power production. However, the commerciality of these technologies is not expected before 2030.

Critical role of gas in heavy industries

Gas has historically held an important position within the industrial sector, comprising around 27% of global gas consumption in 2022. Gas serves as a reactant, feedstock, and vital source of process heat within industries. Firstly, gas is the key feedstock to produce hydrogen for the refining and chemical industries. Secondly, gas serves as a feedstock for ammonia and methanol production, crucial for fertiliser and other industrial value chains. These products are expected to be of high demand with rising population and economic development, as demand for food and consumer goods increases. Lastly, gas is typically used in heat processes and is even suitable for processes requiring temperatures of more than 1,000 degrees Celsius due

Figure 87: Process temperature by industrial sector



Source: Australian Renewable Energy Agency; Rystad Energy

to its high energy density and controllable combustion characteristics, as seen in Figure 87. In the coming decade, industrial processes demanding high temperatures would likely remain gas-driven, particularly within the metals, glass, ammonia, and ceramics sectors. While these sectors also have lower heating requirements that could be tackled by electrification, the largest share of gas consumption is directed at the highest temperature parts of the processes.

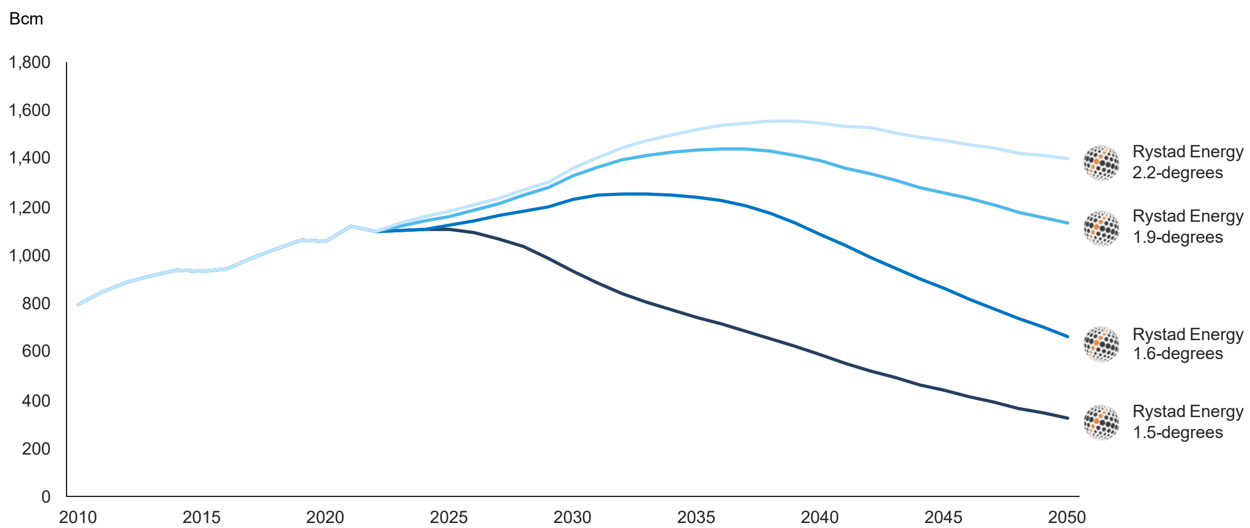
Moving forward, natural gas will continue to play an important role in the industrial sector, though low carbon alternatives – electrification of processes, green gases, and using CCUS units – are available to decarbonise some industrial processes, if they can be produced at sufficient scale and competitive costs. It is important to note that coal is currently the main industrial fuel source, particularly in Asia, accounting for 37.7% of global total industrial energy use in 2022 and producing very high greenhouse gas emissions (nearly 40% of total energy-related greenhouse gas emissions) and air pollution. This leaves a lot of room for fuel switching to natural gas to improve air quality and the local environment and significantly cut emissions.

For industrial processes that are less heat intensive (up to 500 degrees Celsius) such as food drying and beverage processes, electrified heating is a viable decarbonisation option that would likely reduce the demand for natural gas. For processes with higher heat requirements (up to 1,000 degrees Celsius), electric furnaces could be used, but technologies like these are still in development. For example, BASF is developing electric petrochemical cracking furnaces that can reach 850 degrees Celsius, planned for full scale operations by 2030. However, electrified equipment would fare worse than gas when it comes to heat-intensive processes that require reliable heat generation for an extended period of time. Electrifying the heavy industrial load would also place significant strain on the electrical grid. Additionally, gas-fired heat processes are more cost competitive than electrified processes due to the availability of natural gas and mature technologies. As such, unless technological advances reach maturity and costs become comparable to conventional equipment, gas will continue to be necessary.

Installing CCUS units at industrial sites is another option to decarbonise hard-to-abate industrial processes in cement production and steel manufacturing. For example, the Longship project captures 800,000 tonnes of CO2 annually from Heidelberg Material's cement factory and Hafslund Oslo Celsio's waste incineration facility, to be stored in geological formations beneath the North Sea. Although the number of CCUS projects is growing globally, challenges such as limited access to funding and a lack of supportive policies are recognised as the main barriers hindering large-scale CCS developments. In terms of CCUS policies, though a positive shift has been witnessed in 2023 through policies like the United States' IRA, EU's Net Zero Industry Act, and Japan's long-term CCS roadmaps, governments would need to assist developers in creating a favourable financing and regulatory environment for CCS developments to proceed.

The usage of low carbon gases will be an essential part of the effort to reduce the emissions from the

Figure 88: Industrial gas consumption in varying degree-scenarios



Source: Rystad Energy

industrial sector. Decarbonisation enabled by low carbon hydrogen and ammonia is particularly applicable to processes that currently use grey hydrogen or ammonia as feedstock, and processes that rely on fossil fuels to reach high temperatures (> 1,000 degrees Celsius). Biomethane offers a one-to-one direct substitution of natural gas, requiring no need for infrastructure modification. Although low carbon gases show promise in various applications, challenges related to scalability and cost remain.

From the above assessment, it is clear that gas will continue to play an important role in the energy transition, and this brings back the question of planning for sufficient supply to be available for both natural gas and the incoming low carbon gases. This takes into account the demand augmentation from adoption of alternative technologies in the industrial sectors where it is possible and affordable to accomplish.

Rystad Energy show the pathways of industrial gas demand through varying degree-scenarios (Figure 88). The role of gas remains significant, even in the 1.5 and 1.6-degree scenarios, due to limited alternatives. In the higher degree scenarios, the industrial sector increases gas consumption, due to an uptick in industrial activity and because gas is used to replace other fossil fuels, followed by a gradual decline post-2035. However, the decline is slowed by new CCUS facilities and the retrofitting of existing facilities with CCUS.

Transition of the building sector

The buildings sector (residential and commercial) consumed approximately 21% of natural gas in 2022, amounting to around 991 Bcm. Natural gas is commonly used as a fuel for heating, cooking, and providing power for appliances and utilities in the buildings sector. Towards 2030 and beyond, gas will continue to play an important role in this sector, with the largest decarbonisation efforts likely coming from increased efficiency and conservation. Towards 2050, natural gas displacement can be expected across different regions, based on the adoption of low carbon gases and electrification.

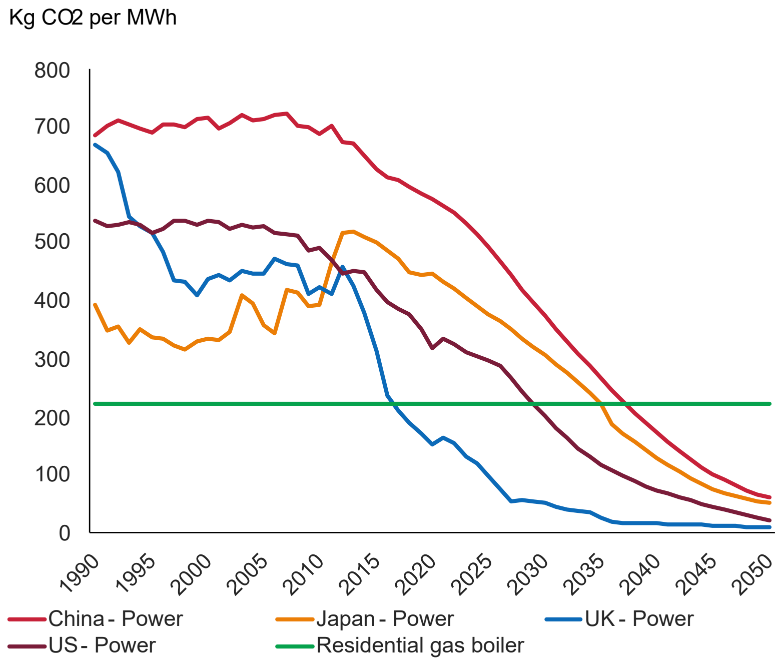
A highly scalable approach to decarbonising buildings involves leveraging energy efficiency and conservation measures. Energy efficiency stands as a readily accessible method for curtailing energy usage by retrofitting appliances, repurposing surplus heat, enhancing insulation, and using efficient demand response measures. Numerous policies across Europe (REPowerEU) and North America (IRA) have underscored energy efficiency as a key measure for reducing emissions and eventually attaining net-zero emission goals. In Asia, Japan immediately comes to mind, having one of the lowest energy intensities in the world. This was achieved via policies such as the “Rational Use of Energy Act” that

that came into place in 1979 to promote periodic reporting on energy consumption and reduction efforts, and to encourage competition among companies in energy efficiency. Its most recent policy – "New Strategic Energy Plan" – aims to take energy efficiency improvements further, setting a 40% energy efficiency improvement target from 2013 to 2030. In fact, the IEA has highlighted that comprehensive energy efficiency renovations are key for decarbonisation, potentially improving energy intensity per square metre by more than 50%.

Another buildings decarbonisation pathway involves the integration of low carbon gases, such as hydrogen and biomethane, into the gas supply. This can either be done through partial blending or full substitution. Partial blending is a transitionary alternative towards lower emissions from the buildings segment without doing large overhauls of residential infrastructure, and with biomethane full substitution does not require any retrofitting. Low carbon gases can significantly reduce the carbon intensity of energy consumption in buildings, while leveraging existing gas infrastructure. However, there are several barriers pertaining to cost and scale which need to be overcome before wider scale and adoption can occur.

Electrification has been one of the main decarbonisation pathways in many net-zero strategies in recent years. Some countries already have low power grid emissions, and electrification in these cases will result in reduced emissions, while in the cases where electricity emissions is higher than buildings

Figure 89: Emissions from residential gas versus power sector by country[28]



Source: Rystad Energy

emissions, electrifying buildings would have the opposite effect. It is important to highlight that electrification of buildings will create significant additional demand for electricity, requiring additional low carbon power generation, transmission, and distribution development. A study conducted by "The Center on Global Energy Policy" see electricity demand to potentially grow from 3.9 PWh to more than 15 PWh in the United States with large scale electrification.

Electric heat pumps are a popular solution for the electrification of heating as they enable efficient transfer of heat from the environment (air, ground, or water) into buildings with the help of a refrigerant fluid. Its efficiency can reach more than 300%, meaning heat pumps can generate three to four times the heat compared to the electricity they consume. Governments across Europe, North America, and Asia have been providing grants to incentivise the installation of heat pumps. For example, the United Kingdom government has set out plans to offer 5,000 Pounds grant to help 90,000 households install heat pumps between 2022 and 2024). Japan subsidises heat pumps as an energy saving project in residential, industrial, and commercial sectors. It is important to note that decarbonisation through electrified appliances depends on the grid's carbon footprint. To achieve low or net-zero emissions, the power grid must be improved to provide cleaner electricity for these appliances.

Additionally, despite policy shifts favouring electrification, significant switching costs remain a challenge. This is exemplified through the delayed gas boiler

[28] *Power mix according to 2-degree scenario, assumed 90% efficiency for residential gas boilers, power mix carbon intensity with the IPCC references from chapter 1 and Rystad Energy's view on future power mix distribution. The power results show the emissions per MWh if electricity is utilised for heating.*

ban in Germany from 2024 to 2028 due to public outcry against high switching costs to heat pumps. For comparison, the upfront cost of a gas boiler in Germany is between 1,000 Euros and 3,000 Euros, while the installation of a heat pump system costs upwards of 10,000 Euros, after subsidies and grants. Moreover, given the historical cost effectiveness of residential gas compared to electricity, this further enhances the case for gas boilers.

In conclusion, while electrification will make sense in certain parts of the building segment, similarly to industry, it will not work cost and environmentally efficiently everywhere. The economics of switching will play an important role, and in many cases, gas will remain a viable option and continue to play an important in the building sector, particularly with the direct decarbonisation options via low carbon gases. While electrification is an important pathway, it is not the only route to decarbonisation, and the policy focus should fall on finding solutions that provide the highest emissions reduction return on investment. To decarbonise the buildings sector, governments should first prioritise energy conservation and efficiency measures to manage consumption. This can bridge the longer-term pathways of transitioning towards low carbon gases and electrification.

Methane emission reduction initiatives

Mitigating methane emissions plays a major part in meeting the Paris greenhouse gas (GHG) reduction goals. Methane is the second largest GHG after carbon dioxide (CO2). Its warming effect is however significantly stronger in the short-term, which makes it a more potent near-term climate forcer than CO2. Therefore, methane emissions mitigation is an urgent matter, as long as it is not at the expense of a continued step-up in CO2 mitigation – which has more significant compounding effect on long-term global warming. Even amid an expected ramp-up of renewable energy supply, the recurring prospect of intermittency causing shortfalls of solar PV and wind power creates a need for complementary energy sources to always be available. Natural gas is poised to play a key role in this respect, but emission reduction is crucial for natural gas and LNG to remain relevant as an energy source in the long term.

Many initiatives have been launched to abate methane emissions from the natural gas value chain, the most prominent of which is the Global Methane Pledge (GMP), launched at the

Table 8: Prominent industry initiatives in reducing methane emissions

Initiatives	Description	Targets		Members
Global Methane Pledge	A global effort to reduce methane emissions, launched at COP 26.	30%	To cut global methane emissions by at least 30% by 2030, using a 2020 baseline.	Australia, France, Saudi Arabia, USA, and 146 other countries.
OGCI	A CEO-led initiative from 12 energy companies focused on CCUS, methane emissions reductions, and tackling transport emissions.	45%	Leading the oil and gas industry's response to climate change and speeding up action towards net zero emissions, in accordance to the Paris Agreement, which calls for a reduction in emissions by 45% by 2030.	aramco, bp, Chevron, CNPC Aramco, BP, Chevron, CNPC, and 8 other companies.
OGMP Oil And Gas Methane Partnership 2.0	A flagship oil and gas reporting and mitigation programme for methane emissions.	60%	Helping oil and gas companies understand their methane emission profiles through five different levels of reporting and subsequently mitigate these emissions in a cost-effective way, focusing on the most material sources. To achieve 60% - 75% reductions in methane emissions by 2030.	2i Rete Gas, ADNOC, ADRIGAS, AkerBP 2i Rete Gas, Abu Dhabi National Oil Company, Adrigas SpA, Aker BP, and 101 other companies.
METHANE GUIDING PRINCIPLES	A partnership between industry and government to develop guidance in methane emissions reporting and reduction.	No specific targets announced.	To 1) continually reduce methane emissions, 2) advance strong performance across the gas supply chain, 3) improve accuracy of methane emissions data, 4) advocate sound policy and regulations on methane emissions, and 5) increase transparency.	apa, Baker Hughes, 北京燃气 BEIJING GAS, bp Apa, Baker Hughes, Beijing Gas, BP, and 23 other signatories.
CLEAN	The only initiative specifically seeking to decrease methane emissions in the LNG value chain, created by the world's largest LNG buyers.	No specific targets announced.	The "Coalition for LNG Emission Abatement toward Net-zero" (CLEAN), recognizes LNG as a transition fuel and aims to increase the visibility of methane emissions with LNG suppliers, and develop and share best practices to reduce emissions.	Jera, KOGAS Kogas and Jera, with the suppport of the governments of Japan, USA, Korea, Australia, and EU.

Source: Global Methane Pledge; Oil and Gas Climate Initiative; Oil and Gas Methane Partnership 2.0; Methane Guiding Principles; Jera; Kogas

COP26 summit in November 2021. It is led by the United States and the EU and has been joined by more than 100 countries, representing about 50% of global emissions, and more than two-thirds of the global GDP. The aim of the initiative is to reduce global anthropogenic methane emissions across all sectors by at least 30% by 2030, compared to 2020 levels. Furthermore, the IGU has been a prominent proponent of ongoing efforts to measure, record, and minimise methane emissions among its members and beyond, a commitment that dates to at least 2016 when the IGU Group of Experts on Methane Emissions was initially established.

There are also several other active industry initiatives tackling methane emissions, namely the Oil & Gas Methane Partnership 2.0 (OGMP 2.0) - referred to as the gold standard of methane emissions reporting within the oil and gas industry, the Oil and Gas Climate initiative, Methane Guiding Principles, and the Coalition for LNG Emission Abatement toward Net-zero (CLEAN). Table 8 shows a summary of the most prominent industry initiatives in place to reduce methane emissions across the oil and gas industry.

For the LNG sector specifically, CLEAN is a private-public initiative among Japan's Jera, South Korea's Kogas, the European Commission, and the governments of Japan, South Korea, Australia, and the United States, and was launched recently to facilitate the monitoring and abatement of methane throughout the LNG value chain. The initiative brings together LNG buyers and producers to collectively mitigate methane emissions in LNG to boost its allure as a transition fuel.

Methane emissions can occur through the entire natural gas and LNG value chain, and LNG but are most prevalent during gas production and shipping. In general, there are three ways methane gets emitted in the natural gas value chain: through fugitive emissions, flaring, and venting of methane.

4 / LNG as a Critical Conduit for an Orderly Energy Transition

Liquefied natural gas (LNG) technology has introduced an unmatched scalability and flexibility to natural gas as an energy source. This chapter explores the role of LNG in providing flexible and resilient energy supply. It also investigates the pathways for the decarbonisation of its production and distribution within the energy transition, and the potential future role of natural gas infrastructure as an enabler and carrier of low carbon gases. This is an important part of making investments in natural gas related infrastructure future proof.

Highlights

- **Conversion of natural gas to LNG introduces unmatched scalability and flexibility, often replacing high-emitting sources like coal and fuel oil.** The dynamic distribution of LNG allows for the creation of "virtual pipelines" that can enable access to energy for developing regions and remote areas where piped gas is not a viable option. In 2022, LNG trade connected "exporting markets" to markets with importing capabilities, expanding access to areas where pipelines could not reach. The flexibility of LNG has been affirmed on numerous occasions in recent years, most recently during the war in Ukraine with increased imports to Europe, but also after the Fukushima nuclear disaster in Japan in 2011, and the experience of Europe last year has demonstrated the remarkable speed with which access to LNG can be enabled, using FSRU technology. In less than a year, Germany was able to begin import of LNG for the first time to offset its losses of Russian pipeline gas imports.

- **Floating regasification units have been essential for Europe to quickly replace piped gas imports following the outset of the Russia-Ukraine war, with the region seeing an increase in regasification capacity of around 60% from year end 2022 to August 2023.** This displays the flexibility that floating liquefaction and regasification facilities introduce within the LNG value chain. Floating facilities typically have lower capital cost and shorter lead time and can be moved and reused in new locations if needed. Furthermore, the location of the facility is not constrained by typical onshore infrastructure challenges and regulations.

- **Small-scale LNG (ssLNG) is uniquely positioned to provide reliable and cost-efficient energy in areas such as small, remote settlements or islands, and in developing regions.** Often, the alternatives are high emission energy sources like coal, diesel, and traditional biomass. For instance, Sub-Saharan Africa relies heavily on oil to support its decentralised power generation, with distributed diesel capacity alone estimated to somewhere between 45GW and 100GW[29]. Moreover, ssLNG is an attractive fuel option, especially viable in shipping and long-haul heavy-duty road transport, offering a competitive and more environmentally friendly alternative to oil and diesel. LNG emits zero sulphur oxides (SOx) and particulate matter (PM) and 90% less nitrogen oxides (NOx) compared to combustion of heavy fuel oil[30].

- **Bio-methane and e-methane have the same composition as natural gas, meaning that they can utilise existing LNG infrastructure without adjustments, which could make them attractive and competitive options for decarbonisation.** Further, the potential of utilising existing LNG infrastructure for liquid hydrogen carriers like liquid hydrogen and ammonia is gaining traction in several parts of the world, leading to increased investments and R&D efforts.

- **New infrastructure investments should be developed with the compatibility of low carbon and renewable gases in mind.** This is an important part of future proofing investments in gas and LNG infrastructure to keep the energy source relevant and financially viable at current levels, and to reduce the risk of becoming stranded with the inevitable development towards low carbon gases. As with the rest of the supply chain, it is pivotal to build on the aggressive elimination of methane emissions to preserve the environmental value of gas for the energy transition and beyond.

[29] *IGU "Gas for Africa 2023"*
[30] *Sea-LNG "LNG as a maritime fuel – The investment opportunity"*

The role of LNG in future energy systems

As discussed in the previous sections, the required massive surge in the share of renewable energy through the energy transition, will intensify the need for responsive dispatchable balancing sources of energy to ensure that energy demand is continuously met. While batteries are expected to fulfil most of the balancing needs for shorter periods of peak and intermittency events, natural gas and low carbon gases will play an essential role as a reliable and cost-efficient energy source to secure reliable supply during longer gap periods. This assumption is included in all demand scenarios evaluated in this report, signifying the crucial role natural gas and low carbon gases plays in future electricity systems. In addition to power supply, there will remain areas of the economies and regions of the world where electrification may not be the right solution to decarbonise, either due to technical limitations, or due to cost. In these instances, the availability of affordable, reliable, and efficient low carbon gaseous energy will be critical to maintain stable and sufficient energy supply.

In addition to the dispatchable characteristics of natural gas, its conversion to LNG introduces unmatched scalability and flexibility. The dynamic distribution modes of LNG, that include primarily shipping, but also increasingly truck in smaller-scale, function as "virtual pipelines", supplying developing regions and remote areas where piped gas is not a viable option. This often reduces emissions and improves air quality due to the replacement of high-emitting sources like coal and diesel. The flexibility of LNG has been displayed on numerous occasions - particularly during the war in Ukraine, when the United States increased its exports to Europe by 159% from 2021 to 2022, shifting traditional LNG trade flow patterns from Asia to Europe, as previously discussed in Chapter 1. The 2011 Fukushima nuclear disaster in Japan was another demonstration of the criticality and flexibility that LNG offers. Japan's gas imports surged from 91 Bcm in 2010 to 118 Bcm in 2012, as LNG arrived at the rescue, offsetting the sudden loss of key power-generation resource when the Fukushima Daiichi nuclear plant was destroyed. This in turn made Japan the largest LNG importer in the world by a significant margin.

Small-scale LNG for increased energy accessibility

The flexibility of LNG stems largely from its scalability. LNG can be provided from large liquefaction and regasification facilities feeding into the pipeline network of large cities and regions, or it can come from small-scale terminals providing energy to remote settlements, trucks, or ships. In areas such as small, remote settlements or islands, with limited gas demand and challenging conditions for large-scale distribution and traditional infrastructure, small-scale LNG (ssLNG) is uniquely positioned to provide reliable and cost-effective energy. Often, the alternatives are higher-emission energy sources like diesel gensets, and traditional biomass. For instance, Sub-Saharan Africa relies heavily on oil to support its decentralised power generation, with distributed diesel capacity alone estimated to be anywhere between 45GW and 100GW[31]. Diesel is highly polluting with high emissions, and a high-cost energy resource. Furthermore, increased demand for long-duration balancing in the future electricity systems calls for dispatchable energy sources, such as gas. However, consumption is likely to be smaller in absolute quantities, more volatile and more widely distributed compared to current norms, given the uptick of renewables, micro-grids, and off-grid solutions, further exemplifying the relevance of ssLNG.

[31] *IGU "Gas for Africa 2023"*

Furthermore, ssLNG typically requires lower investments and shorter lead times than traditional LNG, thus boosting its popularity in developing regions where satellite terminals can be set up. As more marginal gas resources become available and smaller demand centres emerge, ssLNG becomes crucial in increasing LNG production and usage going forward. For example, the Port Edward LNG project in Canada is planned take two years to construct and cost 300 million CAD, and when compared to larger LNG facilities like LNG Canada that is only about 85% completed after 5 years of construction and costs 100 times more in capital cost, the advantages of ssLNG are clear. The Port Edward LNG plant aims to supply LNG for export and for domestic customers in remote communities looking to switch to cleaner fuels such as those in forestry camps and mining facilities, which would otherwise not be served by larger LNG facilities like LNG Canada. Moreover, ssLNG is an attractive fuel option, both on land and at sea. LNG offers a competitive and more environmentally friendly alternative to oil and diesel, reducing emissions and most importantly eliminating harmful air pollution. During combustion, LNG emits zero sulphur oxides (SOx) and particulate matter (PM) and 90% less nitrogen oxides (NOx) compared to heavy fuel oil[32]. It is particularly viable in shipping and heavy road transport. In China, LNG-fuelled heavy-duty trucks and buses have seen massive growth over the past decade. This development has largely been driven by government policies and regulations to address local air pollution large cities, as natural gas does not emit soot, dust, or PM during combustion. For the heavy-duty truck segment, LNG is expected to remain the most effective fuel in terms of emissions in the medium term, given the challenges facing alternative solutions. Electrification of the truck fleet is a complex option hindered by strict battery requirements pertaining to durability and performance, whereas synthetic fuels are not financially feasible at present.

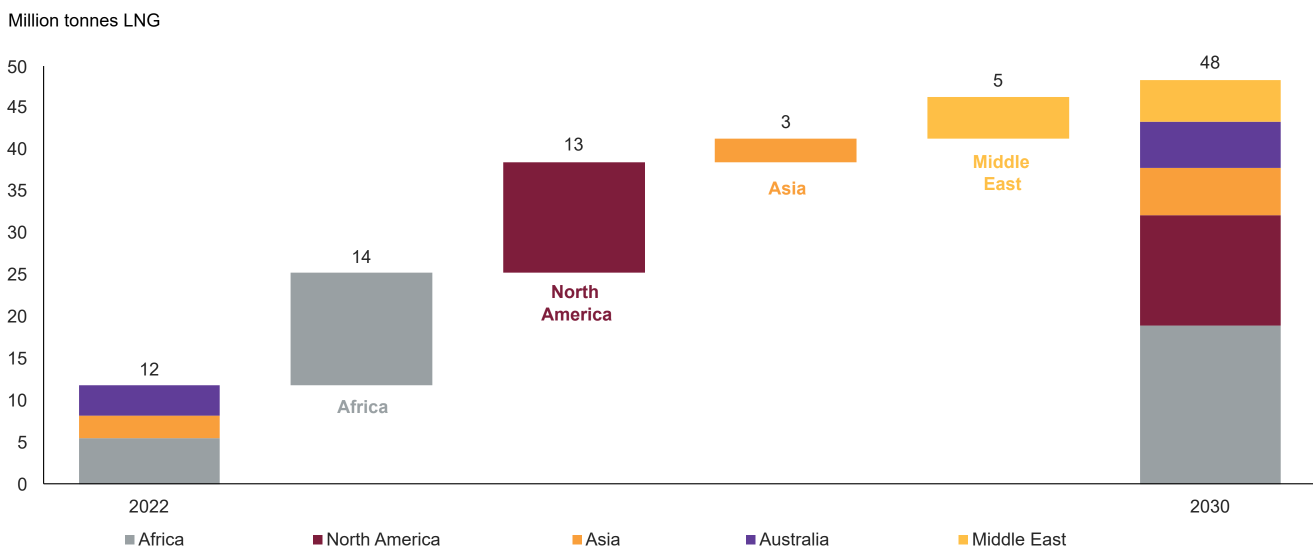
In marine transport, dramatic changes in regulations – the International Maritime Organisation's fuel oil Sulphur limit was tightened from 3.5% to 0.5% in 2020 – have allowed LNG to gain traction as a fuel, particularly due to the considerably lower emissions of SOx and NOx. In 2022, global LNG bunkering activity decreased as oil-based fuels traded at significant discounts to global LNG prices. However, as of early 2023, LNG prices have once again become competitive with fuel oil, further encouraging a rapidly expanding LNG-fuelled orderbook and ensuring continuity with the acceleration of decarbonisation measures. Indeed, more than 50% of today's orders for alternative fuelled ships are LNG-ready. It is currently the only technologically mature alternative to oil-based marine fuels: other carbon neutral fuels, such as hydrogen, green ammonia, or methanol, are still facing technological, infrastructural, economic, and regulatory issues, and are not expected to become widely available in the very near future.

Nigeria, Africa's largest exporter of LNG, has recently been increasing its domestic production of natural gas, driven by the government's promotion of gas to replace more emission intensive energy sources, and to improve energy accessibility in the country. The growth in the domestic market has notably been enabled through small-scale applications. This has further boosted the private sector investments in ssLNG, which aims to take advantage of the cleaner and cheaper alternative to diesel. For instance, in 2016, private player Greenville LNG commissioned a 450 million USD mini-LNG and gas processing facility in Rumuji, Rivers State, including three liquefaction trains, boasting a combined LNG production capacity of 2,250 tonnes per day. From this facility, LNG is distributed throughout Nigeria using LNG-powered trucks equipped with cryogenic tanks, each with a carrying capacity of 23 tonnes of LNG. Notably, Nigeria has managed to monetise the associated gas from its oil production, becoming the key exporter of LNG on the continent. Other well-established gas companies, including Axxela and Greenfuels, are now focusing on mini-LNG facilities to diversify their offering. Axxela has signed a contract for engineering, procurement, and construction of a mini-LNG plant in Ajaokuta, aimed to supply the northern states with gas through truck-based distribution. The development of ssLNG in Nigeria has effectively democratised gas by increasing the availability of energy to the public, in turn facilitating economic growth. This strategy could in turn be mirrored in neighbouring countries to bolster industrial activity and economic growth.

[32] *Sea-LNG "LNG as a maritime fuel – The investment opportunity"*

Flexible LNG to balance out troughs

Figure 90: Installed FLNG capacity per region



Source: Rystad Energy

The success of the traditional LNG value chain is dependent on economies of scale, driven by considerable investment requirements in infrastructure. The introduction of floating facilities such as floating LNG (FLNG), floating storage and regasification units (FSRU), floating regasification units (FRU),and floating storage units (FSU) has unlocked a new degree of flexibility within the LNG and broader energy value chain, as the location of the facility is not constrained by typical onshore infrastructure challenges and regulations. Furthermore, floating facilities can be redeployed to new locations if needed.

FLNG offers the possibility to cost-effectively commercialise small or stranded gas reserves, especially in areas where there are limited or no existing infrastructure. The technology's comparatively low capital cost and short lead time can enable profitable operations even on marginal fields with modest production capacity, partly due to no export pipelines being needed. Furthermore, the cost of FLNG has fallen in recent years, partly driven by the standardisation of newer FLNG vessels. Rather than being customised for usage in a specific field, these vessels are designed to have greater flexibility in deployment with reduced lead time, offering significant cost savings. In addition, FLNGs offer various advantages over onshore projects, which often face land constraints and complex environmental approval processes.

The West African region is home to many marginal gas fields with stranded reserves and limited existing infrastructure. This is reflected in Africa's market share of 46% of global FLNG capacity installations in 2022. The new projects added in the region last year include Coral South FLNG in Mozambique and the Cameroon FLNG project. Mozambique has struggled to develop its LNG capacity due to safety issues related to the civil unrest that started in the northern parts of the country in 2017. FLNG facilities can reduce risk while still offering economically competitive ways to monetise otherwise stranded gas resources. FLNGs can also serve as an intermediate solution for larger fields, providing early cash flow until onshore liquefaction trains come online.

North America is expected to take the lead in terms of new installed FLNG capacity in the coming years, driven by development in the United States. FLNG is a part of the country's strategy to quickly access gas resources for overseas export, supplementing the rising supplies from onshore LNG facilities. The first upcoming project in the United States, fittingly named Fast LNG, is expected to come online in 2025 with a liquefaction capacity of 2.8 MTPA. The Altamira FLNG project in Mexico is another example of responsive new supply, initiated in June 2022 and expected online by the end of 2023, introducing 2.8 MTPA of LNG to the market.

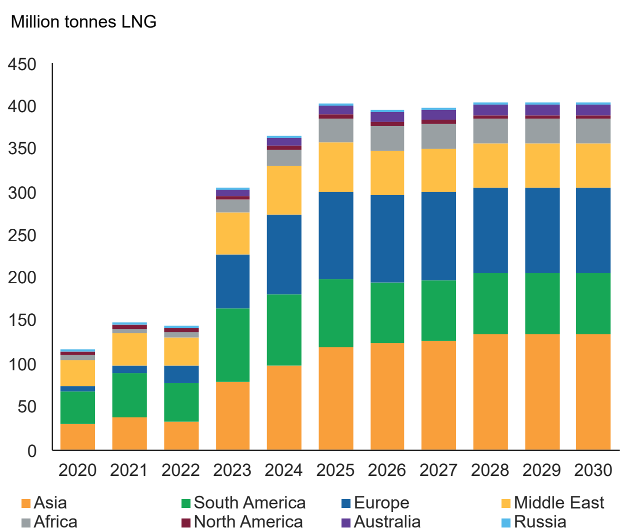
FSRUs are relatively new compared to their onshore counterparts, with the first unit being deployed in the United States in 2005. Since then, the number of FSRUs has surged, representing around 15% of global regasification capacity as of August 2023. This is expected to increase by the end of 2023 with new FSRUs expected to enter the market, especially in Europe. FSRUs played a key role in Europe's response to the energy crisis escalated by the Russia-Ukraine war and the loss of Russian gas volumes. The advantages of FSRUs are like those of FLNG vessels: lower capital costs, shorter lead times especially if existing LNG carriers are retrofitted, flexibility in use, and lower risk as FSRUs can be leased. Historically, South America, the Middle East, and Asia have been the largest markets for FSRUs measured in installed capacity. South America tops the ranking year-to-date with 46 million tonnes of regasification capacity, corresponding to 30% of the global market. Asia and the Middle East each had around 22% of the market, at 33 million tonnes and 32 million tonnes of capacity, respectively. Europe has increased its capacity by around 60% from year end 2022 to year-to-date 2023 and is the fourth largest region with 30 million tonnes of capacity and a market share of 20%.

At that trajectory, Europe is expected to surpass both South America and the Middle East by 2024 in installed regasification capacity. During 2022, 17 new FSRU projects were approved in Europe, amounting to about 65 million tonnes of capacity if realised. In particular, Netherland's Eemshaven FRSU project started operations in record time. It commenced operations in September 2022, only months after project approval due to the geopolitical risks and gas supply shortages that emerged after the start of the Russia-Ukraine crisis in February 2022. The Eemshaven project consists of two vessels – one built as an FSRU in 2017 and the other built as an LNG tanker in 2014 before being converted in 2022. This is the first FSRU project in the Netherlands and it underscores the unique flexibility the concept can offer.

The other 16 approved European projects in 2022 are expected to come online between 2023 and 2025 – four are already operational while three are under construction. This represents lead times of one to two years, further underpinning the flexibility and scalability FSRUs bring to the global gas market.

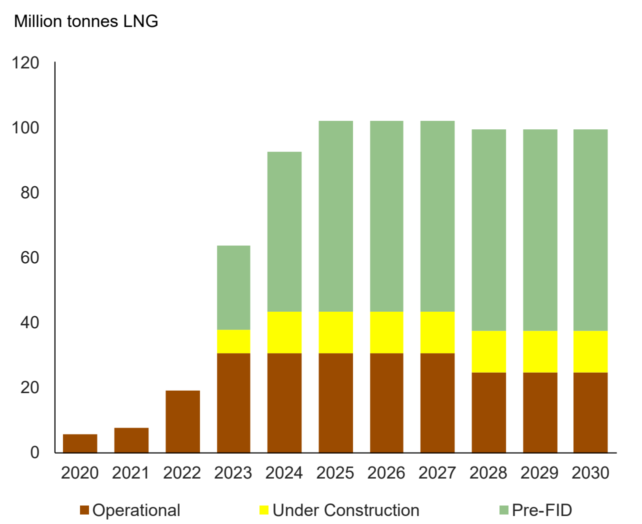
FSRU infrastructure has been invaluable in restoring Europe's energy security, as it opens for new gateways to receive LNG and addresses existing inter-regional infrastructure bottlenecks to facilitate easier movement of gas to consumers. However, it is important to be

Figure 91: Installed FSRU capacity per region



Source: Rystad Energy

Figure 92: European installed FSRU capacity life cycle



Source: Rystad Energy

mindful that while lead times for LNG receiving infrastructure can be less than two years, the production of new volumes to deliver the supply is typically longer. Furthermore, the development of LNG export and import facilities are investments that require long-term planning for the energy system and is hence not as responsive in the immediate term. Here, the flexibility in the utilisation of existing LNG facilities comes into play. Liquefaction plants in the United States posted a utilisation rate of 103% in 2021 due to tightness in the gas market. In 2022, plants in Qatar, the United States and the UAE all produced at more than 100% utilisation, exporting LNG above their nameplate capacities due to shortages caused by the Russia-Ukraine crisis. Similarly, many of the regasification facilities in Europe ran at above 100% capacity. This firstly emphases the responsiveness and scalability of LNG infrastructure, with a critical role in safeguarding energy security, and secondly, it highlights the urgency for rebalancing the market with additional supply and sufficient infrastructure.

Repurposing existing LNG infrastructure for clean and low carbon alternatives

There are several ways of decarbonising and future-proofing the LNG value chain, as LNG infrastructure can play an important role in future energy systems as infrastructure for low carbon gases. This could either be partial decarbonisation with natural gas blended with low carbon gases like hydrogen (see further details in Chapter 3), or through a total refurbishment of equipment and infrastructure used for natural gas and LNG. Both methods are supported by the EU as part of its push to decarbonise gas and increase investments into green projects.

The possibilities of using LNG infrastructure as a carrier of hydrogen and other low carbon gases

The future proofing of LNG infrastructure is based on the possibilities for re-utilisation to process low carbon gases. Examples are liquefied bio- or e-methane, or hydrogen carriers like liquid hydrogen, liquid organic carriers, or liquid ammonia. Both bio-methane and e-methane are especially interesting, as they have the same composition as natural gas, meaning that current LNG infrastructure is 100% compatible with these low carbon liquefied gases. The fact that bio- and e-methane can utilise existing infrastructure, could make them attractive and competitive measures to decarbonise natural gas. For instance, Japan is eyeing a possibility to decarbonise their natural gas consumption through e-methane and has set targets for synthetic methane uptake in existing infrastructure of 1% by 2030 and 90% by 2050. The Japanese gas company Osaka Gas has partnered with companies in both Peru and Australia investigating the possibilities of using surplus supply of renewable energy, e.g., solar PV in Peru, to produce green hydrogen and combine this with either carbon from direct air capture (DAC) or carbon capture from industrial sites to make e-methane. The aim is that this in turn can be transported to Japan as e-LNG using the existing LNG infrastructure, like ships, terminals and regasification facilities. There are, however, large uncertainties in which low carbon gas will be the preferred energy transition gaseous energy carrier, or whether several low carbon gases will be used in parallel to facilitate for the transition to lower carbon gas consumption. Two other prominent solutions for re-utilisation of gas infrastructure are either through liquefied hydrogen (LH2) or converting hydrogen to ammonia, in which both methods include liquefaction. However, hydrogen and natural gas are two different molecules. Liquifying hydrogen requires temperatures as low as -253 degrees Celsius, compared to -163 degrees Celsius for LNG. Due to this difference, refurbishing LNG infrastructure would require large-scale investment in insultation upgrades. According to some estimates, tanks at hydrogen liquefaction and regasification terminals would require insulation with 10 times the thermal resistance compared to tanks for LNG. With current technology at a typical LNG terminal, the tanks account for about 50% of the investment costs, meaning that the capital expenditure involved in such retrofitting is expected to be significant, which in most cases is expected to make it more viable to build new storage tanks. Additionally, due to the small size of the hydrogen molecule, the processes around liquefaction and regasification could be more prone to leakages. This would require hydrogen-specific components such as valves, pipes, pumps, and tanks, which are not compatible with those used for LNG today. Therefore, retrofitting of LNG infrastructure for use in the hydrogen value chain presents substantial challenges in view of high costs in the current technology environment. The area of refurbishment of LNG infrastructure for hydrogen is, however, gaining attention, and further technology development is possible and expected. For instance, Germany is investing 3.8 million euros to study and enable the utilisation of LNG terminals for various types of hydrogen and its derivatives. Furthermore, given the relevant skills and expertise developed within the LNG sector, and the impressive technology innovation and cost reduction experience for natural gas, these are examples of challenges that the gas industry has been solving for decades. For instance, the floating liquefaction and regasification facilities introduced in the mid-2010s and early 2000s respectively, set strict requirements to both weight and size of the traditional equipment. These types of solutions increased the flexibility and wider accessibility of LNG distribution considerably, especially through their suitability for relocation and serving smaller gas resources and demand centres. With sufficient focus and resource, innovation can open new unknown horizons for liquefied low carbon gases.

Import and export infrastructure for ammonia already exists today, typically using ammonia specific vessels or liquefied petroleum gas (LPG) vessels. However, the quantity of traded ammonia is still relatively small. The refurbishment of LNG infrastructure for use in the ammonia value chain is gaining traction. In Europe, this is in part driven by the increased greenfield investments in LNG infrastructure seen after the onset of the Russia-Ukraine war in 2022. For instance, the Stade LNG terminal in Germany, as displayed in Figure 93 below, which is

Figure 93: Hanseatic Energy Hub's planned Stade LNG import terminal in Germany, eventually handling carbon-free fuels

Source: Hanseatic Energy Hub

currently set to become the location for an FSRU by the end of this year, is planned to commence operations as an ammonia-ready facility. The facility operator, The Hanseatic Energy Hub, plans on receiving bio-LNG and synthetic LNG at the terminal, before switching to ammonia. In Asia, Japan's IHI is looking into possible conversions of LNG receiving and storage terminals, that are situated close to gas fuelled power plants, into ammonia-based facilities. This is in conjunction to their partnership with GE to develop gas turbines that can run on 100% ammonia. Furthermore, a challenge related to the use of ammonia as a hydrogen carrier is that while methods for producing ammonia from hydrogen are well known and established through the Haber-Bosch process, the reverse reaction to separate the high purity (fuel cell grade) hydrogen from the nitrogen molecules in ammonia is in the early stages of development. Large amounts of energy are needed for this process, up to 30% of the energy content in the ammonia, which would have to come from renewable energy to ensure that the process is emission-free. Due to this, an important step to enable the uptake of ammonia in new sectors would be to develop offtake technologies that are able to operate on ammonia instead of hydrogen, or commercialisation of ammonia cracking. As of H1 2023, few direct synergies exist between the ammonia and natural gas value chains – however, expectations are for this to develop going forward, with power being an area of probability.

Future role of existing infrastructure

In summary, the LNG infrastructure is bio- and e-methane ready, meaning that the deployment of synthetic and biofuels to decarbonise natural gas and LNG, does not require any investments in refurbishment of existing infrastructure. This a considerable advantage of bio- and synthetic methane compared to other low carbon gases. However, as discussed in Chapter 3, both bio- and synthetic methane is dependent on technological development both to reduce production costs and scale of supply, to enable wider adoption. When it comes to the transition from LNG to both liquefied hydrogen and ammonia, utilising the same infrastructure for storage and distribution, is far from seamless with sizeable technical challenges and uncertainty associated with it. The technical challenges are also expected to drive costs which will impact the competitiveness of hydrogen and ammonia through refurbishment. Also, renewable hydrogen and ammonia are in the early stages when it comes to supply, and both cost and scaling possibilities are expected to see large developments going forward.

As a result, the process of transitioning to low carbon gases is expected to be a stepwise process. However, with targets set by the EU and other nations and organisations, the decarbonisation of gas is inevitable despite large uncertainties tied to the optimal solution to reach overall targets. Technology and ongoing and future R&D developments will determine the preferred solution of low carbon gases, or the optimal combination of them in the future energy mix. In the long term, LNG assets will be used for low carbon gases, blended gases, and traditional natural gas according to different regional value chains and decarbonisation pathways.

There is also large uncertainty tied to the future demand of natural gas, as outlined in the range of outcomes described in the different degree scenarios. Efforts to decarbonise the current production and distribution of gas and LNG, such as the Global Methane Pledge, will contribute to lower global emissions in the short term, while the EU taxonomy further illustrates the importance of investments in gas infrastructure with the ability to switch to low carbon fuels in order to reduce emissions in the longer term. The LNG value chain enhances the unique dispatchability, seasonal storage possibilities, and flexibility of natural gas, low carbon, and renewable gases. Hence, they are expected to remain relevant and important as a means of balancing in the future power mix, which will be characterised by a significant reliance on intermittent renewable energy sources. LNG has proven to be a critical tool in providing flexible energy to the world. This flexibility will continue to become more valuable as the energy transition unfolds. Greater variability in supply and demand conditions, stemming from increases extreme weather events and scaling of intermittent renewable generation, will call for greater energy security assurance resources. LNG is an ideal assurance, and it is important that investments in LNG infrastructure and supply keep pace with the anticipated system needs.

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