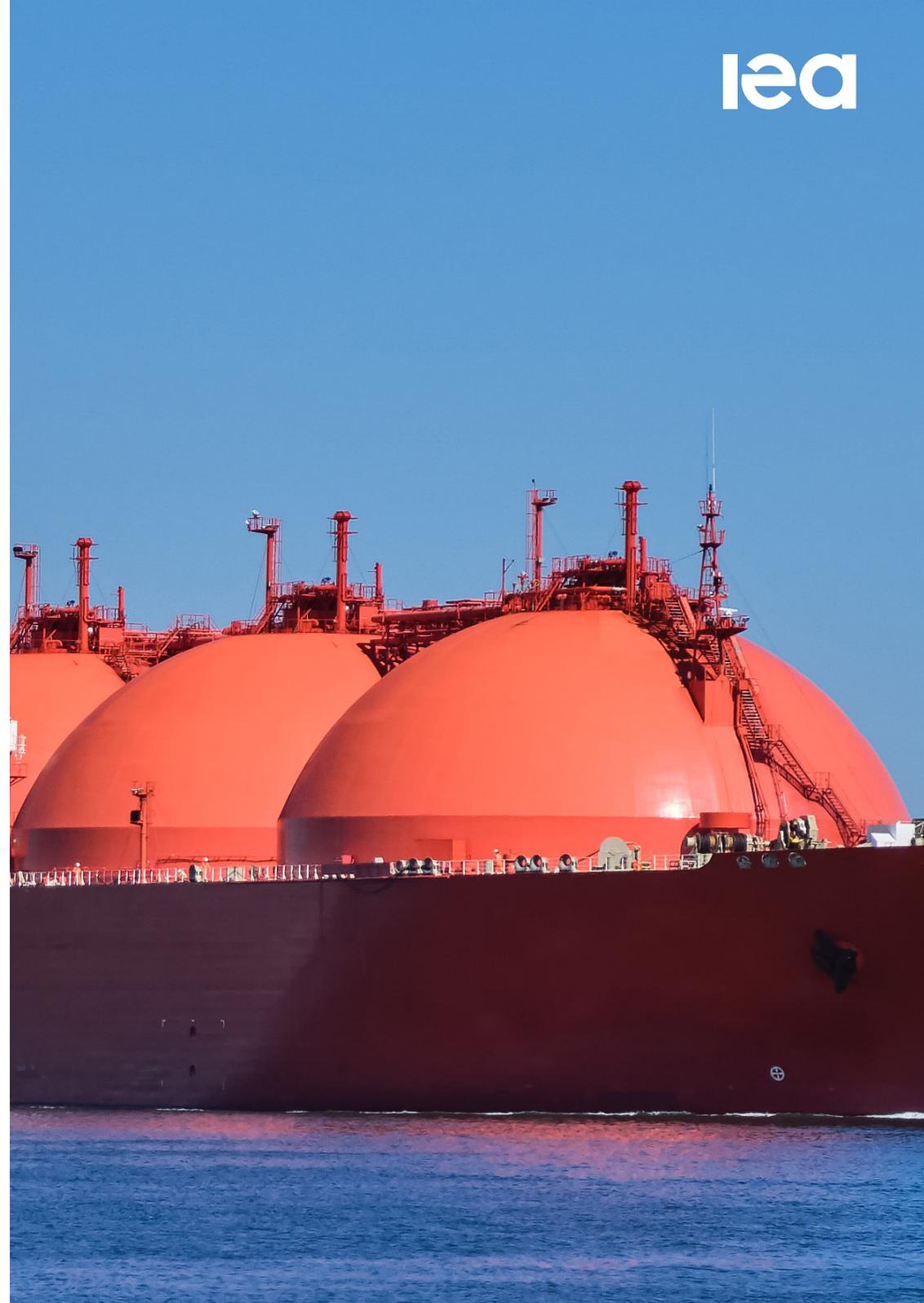


Gas Market Report, Q1-2023

including *Gas Market Highlights 2022*



INTERNATIONAL ENERGY AGENCY

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Abstract

The global natural gas market suffered a major shock in 2022 as Russia cut pipeline deliveries to Europe substantially, placing unprecedented pressure on supply and triggering a global energy crisis. Despite this, European countries were able to fill their underground gas storage sites well above historical averages, supported by a combination of targeted policy measures, a record inflow of liquefied natural gas (LNG) and a steep drop in consumption, particularly in energy-intensive industries. Russia's pipeline cuts also had implications for gas consuming regions beyond Europe, leading to record high spot prices, supply tensions and considerable demand reduction.

Unseasonably mild winter weather in the northern hemisphere, combined with sustained LNG inflows and adequate gas storage inventories put downward pressure on European and Asian spot prices. Nevertheless, the global gas balance is fragile and a number of uncertainties in 2023 exist. Gas importing markets remain exposed to a tight supply environment and the impact of further cuts from Russia are cause for concern. Since the crisis began, governments in Europe and other importing markets have taken strong policy measures to increase their energy resilience and reduce dependence on natural gas.

This new issue of the quarterly *Gas Market Report* includes an overview of the main market highlights for 2022, and an analysis of recent gas market developments with a forecast for 2023.

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Gas market highlights 2022

Record high gas prices and volatility weighed on hub liquidity in 2022

Natural gas hubs enable market participants to trade gas in open, competitive gas markets. Traded products typically range from short-term contracts (e.g., within-day, day-ahead and week-ahead) to products with a delivery horizon several years ahead. Short-term contracts are usually underpinned by physical delivery obligations and are crucial for short-term physical balancing. Products with a longer delivery horizon play an important role in allowing midstream utilities to optimise their portfolios and manage risk.

Hub liquidity ensures that demand from market participants is matched by supply in a time- and cost-efficient manner without causing significant price changes. Greater liquidity improves allocation efficiency and supply security and enables price discovery. One metric used to assess liquidity is the churn rate, which indicates how many times a unit of gas has been exchanged before being delivered to end consumers. Markets with a churn rate above 10 are generally considered to be liquid.

In the United States gas volumes traded on the Henry Hub fell by 5% in 2022. The dip was concentrated in the second half of the year, when traded volumes declined by over 15% compared with the same period in 2021. Tighter market fundamentals drove up natural gas prices to their highest level since 2008, which in turn increased the cost of holding positions and ultimately weighed on

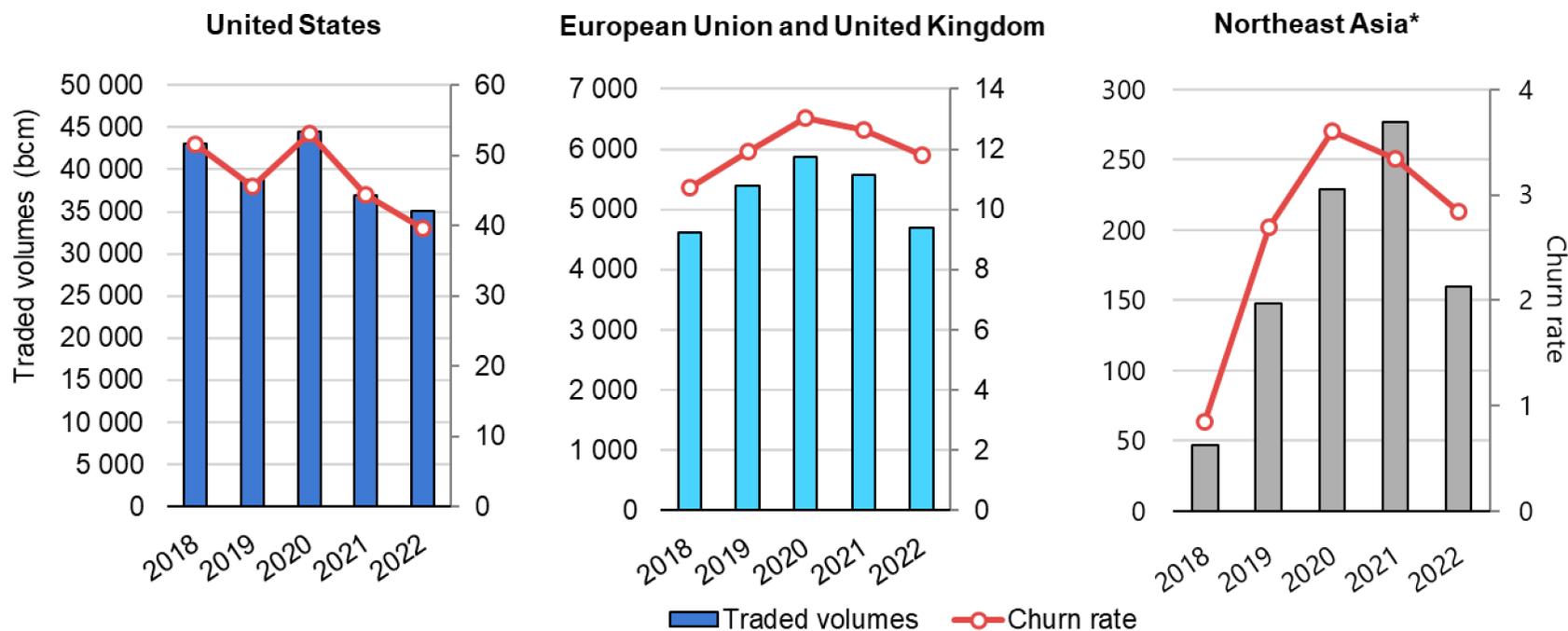
market liquidity. The churn rate fell by almost 10% year-on-year (y-o-y) to just 40, its lowest level since at least 2012.

In the European Union and the United Kingdom, the volume of gas trade plummeted by almost 20% in 2022 to its lowest level since 2017. The steep drop in European gas consumption (down by 13%) together with rapidly rising margin calls weighed on trading volumes. Overall, the churn rate of the combined EU and UK gas markets fell by 7% y-o-y to 11.5 – its lowest level since 2018. The decline in gas trading was the most pronounced during Q3, when gas prices soared to their highest level and traded volumes plummeted by 25% y-o-y. The drop was primarily driven by Europe's largest and most liquid gas hub, the Dutch Title Transfer Facility (TTF), alone accounting for almost 90% of the overall reduction in gas trade. Consequently, its share of the total European gas trade fell from close to 80% in 2021 to below 75% in 2022. Gas trading via exchanges remained more resilient (down by 10%), while over-the-counter (OTC) volumes dropped by around one-third. Consequently, the share traded on exchanges rose to over 55% in 2022.

In Asia trading in ICE JKM derivatives fell by over 40% y-o-y amid lower spot LNG procurements and rising costs associated with trading. The churn rate remained low in the JKM area, declining to just below 3.

Churn rates continued to decline across all key natural gas markets

Estimated traded volumes and churn rates across key natural gas markets, 2018-2022



IEA. CC BY 4.0.

* Northeast Asia = China, Japan and Korea.

Sources: IEA analysis based on various sources, including CME (2022), [Volume and Open Interest](#); ICE (2022), [Report Center](#); London Energy Brokers' Association (2022), [Monthly Volume Reports](#).

The LNG industry in 2022

LNG supply growth was relatively modest in 2022 at 5.5%, despite an unprecedented rise in LNG demand in Europe following the gradual decline in Russian pipeline gas deliveries throughout the year.

The utilisation rate of global liquefaction capacity averaged 84% in 2022, unchanged from 2021 levels and slightly above the 2017-2021 average of 83%. However, the rate in H2 2022 (at 82%) was markedly lower than during the first half of 2022 (at 87%). This mid-year decline was due to a number of unplanned supply disruptions (led by the extended outage at Freeport) as well as technical issues and upstream underperformance at legacy plants, particularly in Algeria, Nigeria, Malaysia and Australia.

Despite the generally favourable market conditions (including high LNG prices and strong contracting activity throughout the year), the long-anticipated wave of final investment decisions (FIDs) on LNG liquefaction projects did not fully materialise in 2022, with only two large-scale plants in the United States (Plaquemines and Corpus Christi Stage 3) and one small-scale floating LNG (FLNG) project in Malaysia (ZLNG Sabah) getting final approval. The total capacity sanctioned last year (34 bcm) is about 7% lower than the 2017-2021 average and a third lower than the FID volume in 2021. This relatively slow FID activity was due in part to rising construction costs and widespread engineering, procurement and construction

(EPC) contract renegotiations throughout the year, and in part to continued reluctance among potential buyers to commit to new LNG contracts in the face of long-term demand uncertainty, elevated pricing and decarbonisation objectives. However, many pre-FID projects (including several developments in North America as well as Qatar's North Field South expansion) made significant progress towards an eventual FID in 2022, leaving the door open to a strong year in 2023.

LNG demand trends were dominated by a sharp surge in gross LNG imports into Europe (up 66 bcm), which was balanced by a steep decline in the rest of the world, particularly in Asia. While the United States supplied approximately two-thirds (43 bcm) of the incremental LNG inflows into Europe, other "swing suppliers" were also able to redirect significant flexible volumes to the European market, with Qatar (5 bcm), Egypt (5 bcm), Norway (3 bcm), Angola (2 bcm), the Russian Federation (hereafter "Russia") (2 bcm) and Trinidad and Tobago (2 bcm) providing the bulk of the remaining one-third.

The strong price premium at onshore European hubs over delivered LNG prices (pre-regasification) in both Europe and Asia – which at times exceeded USD 20/MBtu – incentivised an unprecedented build-up of LNG floating storage on Europe's shores during the final quarter of 2022. At one point in Q4, infrastructure bottlenecks

combined with mild winter temperatures and full storage sites (reflected in wide price differentials) prompted more than 30 laden LNG tankers to wait for available regasification slots in Europe rather than sell their cargoes elsewhere at a discount. By the estimate of S&P Global Commodity Insights, total LNG volumes held up in floating storage around Europe averaged nearly 2 bcm in November 2022, an all-time high and nearly five times the average volume in 2020, the last year when LNG floating storage played a prominent role worldwide amid a global LNG glut.

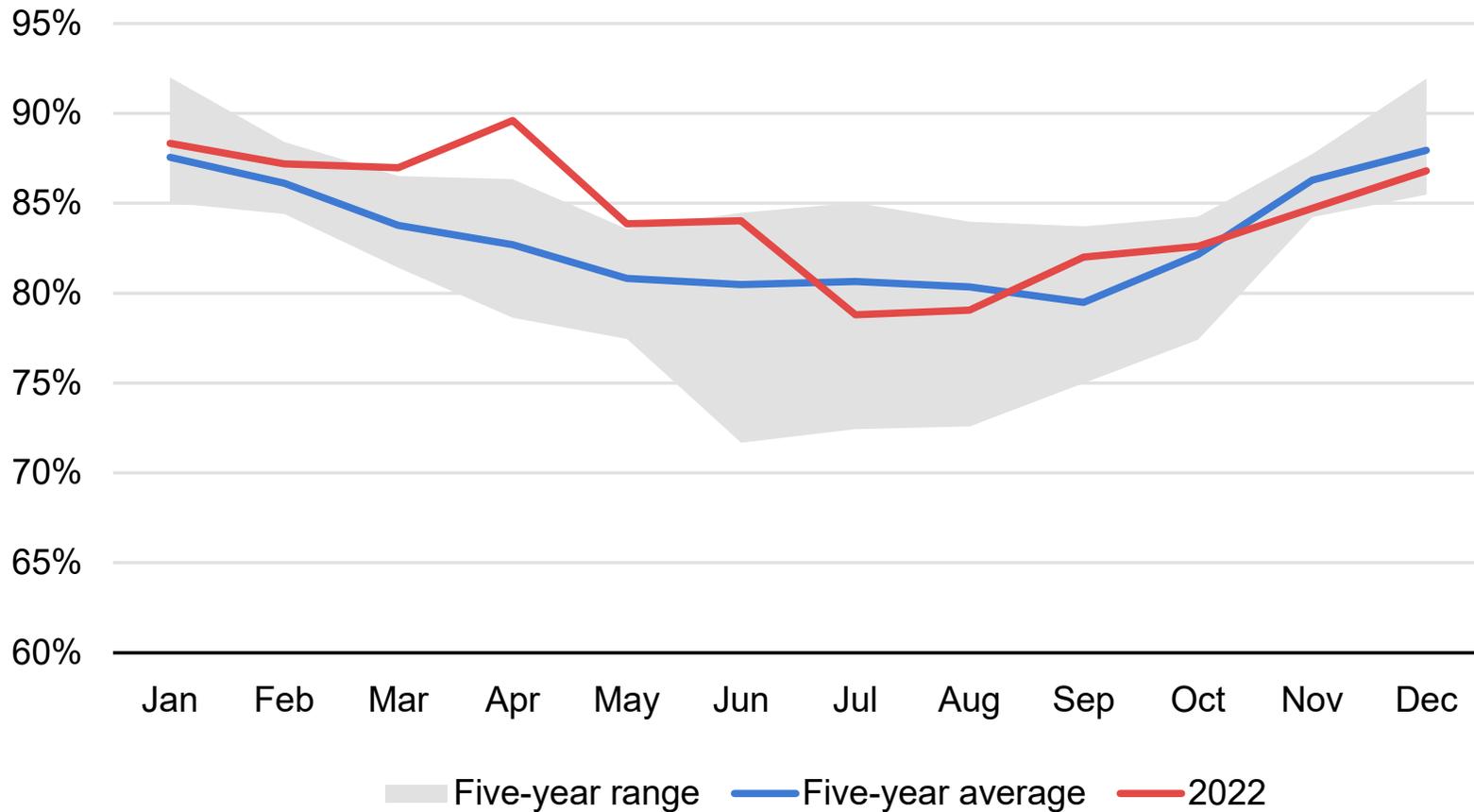
If FID activity was subdued on the liquefaction side, there was a true renaissance of investment in new regasification capacity, with Europe at the centre of the upswing. In response to the progressive reduction in Russian pipeline gas supplies, governments and companies within the European Union have announced, revived or accelerated plans for an estimated 130 bcm of new LNG import capacity since the beginning of 2022, including more than 20 projects based on floating storage regasification units (FSRUs). Of the 130 bcm, about 20 bcm of new regasification capacity was completed by the end of 2022 and another 50 bcm was under development at the start of 2023, with Germany (23 bcm), Italy (10 bcm) and Belgium (8 bcm) accounting for the highest share of under-construction capacity. We estimate that the European Union's effective LNG import capacity (taking into

account existing market constraints and infrastructure bottlenecks) will increase by at least 40 bcm between the end of 2021 and the end of 2023 thanks to the latest wave of investment in new import infrastructure.

LNG carrier orders reached an all-time high of 165 in 2022, according to data from Refinitiv, which represents a staggering 130% increase on 2021. Strong demand and limited capacity at Korean shipyards until 2027 led to steep price increases for new-build LNG vessels (surging to more than USD 250 million by the end of 2022 vs USD 200 million at the end of 2021). This has boosted the presence of Chinese players in the LNG shipbuilding market: Chinese yards received orders for as many as 57 new LNG vessels in 2022, another record and more than a fivefold increase on 2021, according to Refinitiv.

Utilisation of global liquefaction capacity dipped below average in H2 2022

Global LNG liquefaction utilisation



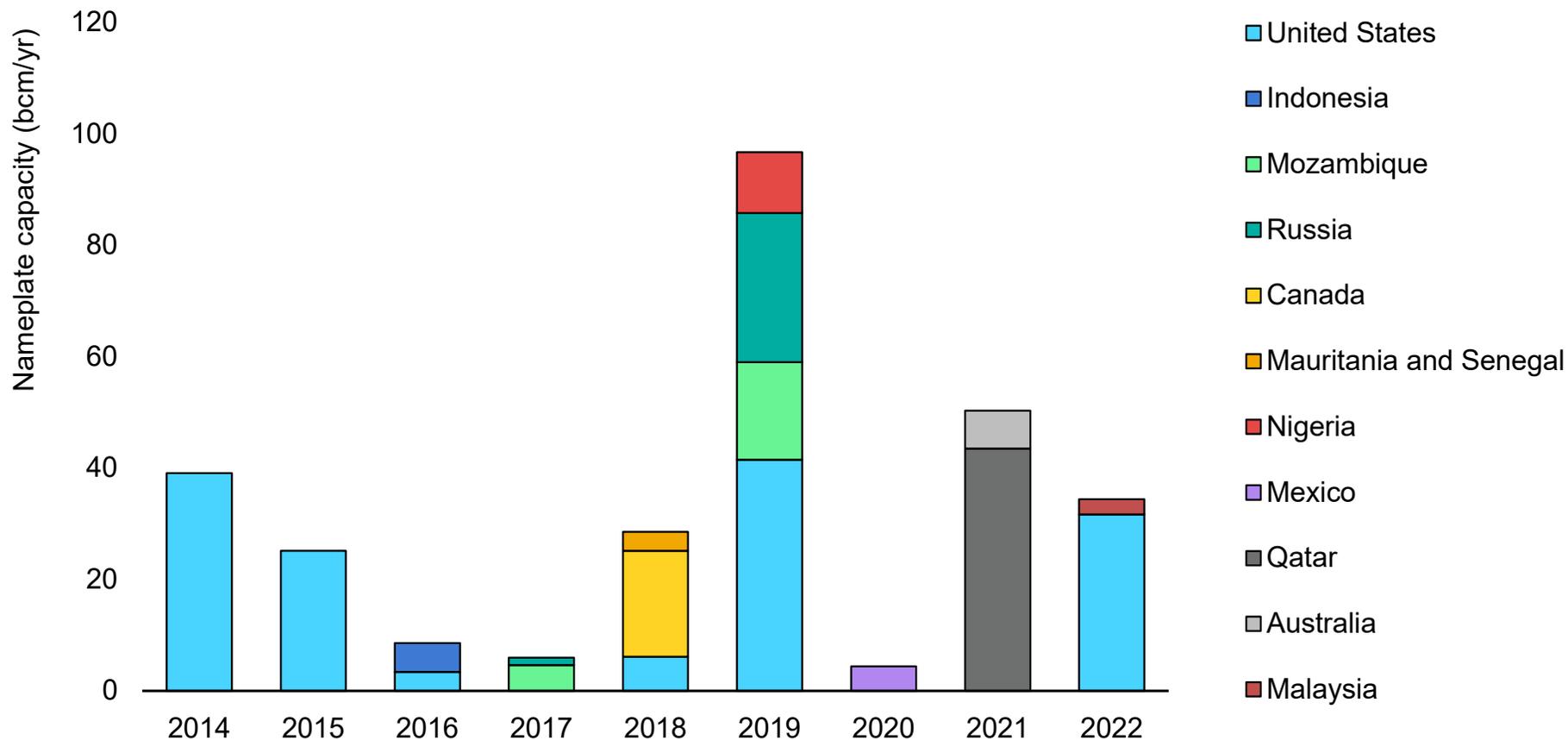
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Source: IEA analysis based on S&P Global Commodity Insights (2023), [Global LNG Balances and Trade](#).



The much-anticipated FID wave for new liquefaction capacity did not materialise in 2022

FIDs for new LNG liquefaction capacity, 2014-2022

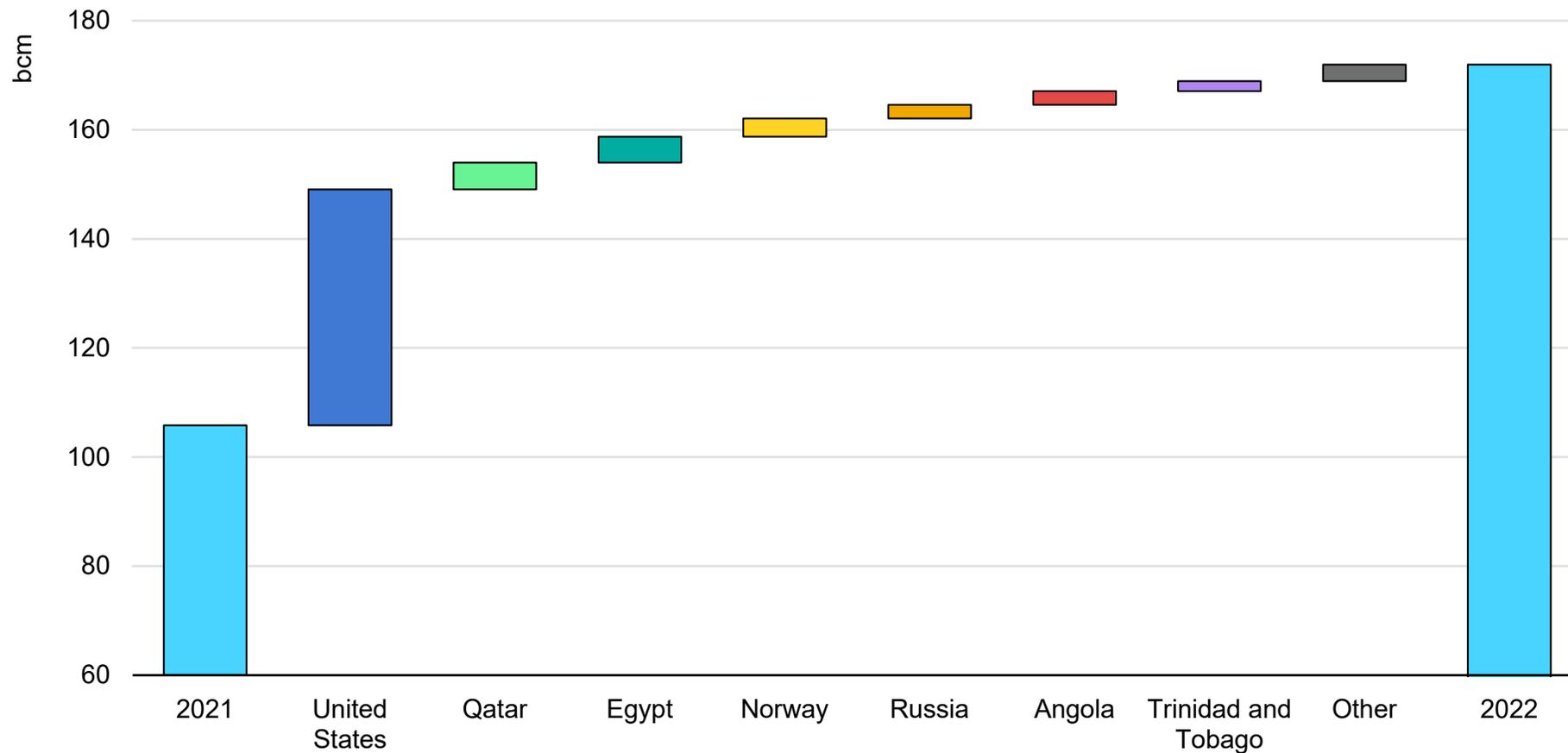


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Source: IEA analysis based on ICIS (2023), [ICIS LNG Edge](#).

The United States supplied two-thirds of Europe’s incremental LNG imports, but other flexible suppliers stepped up deliveries as well

Incremental LNG import flows into Europe by source, 2022 vs 2021

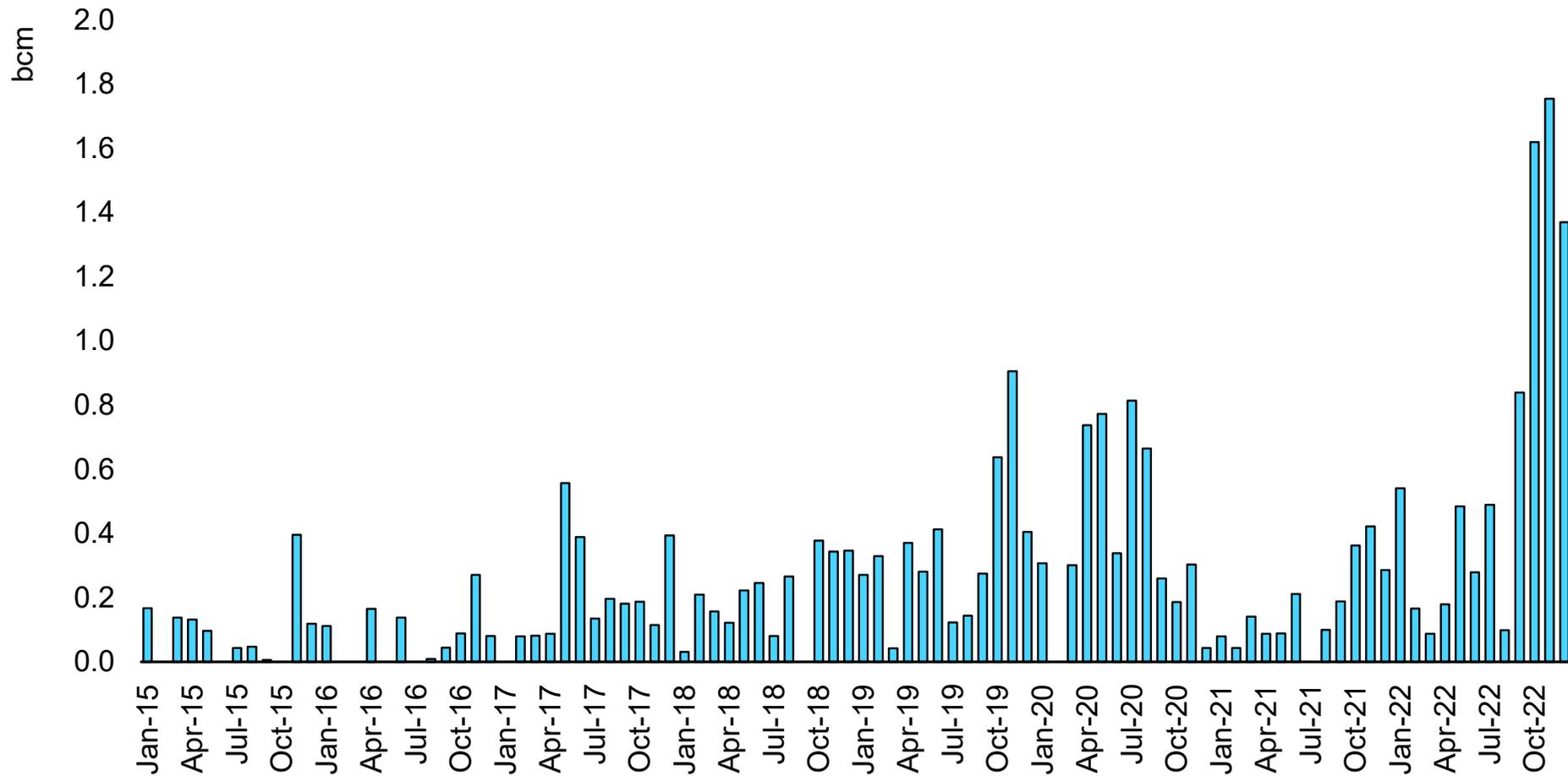


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Source: IEA analysis based on ICIS (2023), [ICIS LNG Edge](#).

Congestion led to record volumes of LNG in floating storage around Europe during Q4 2022

LNG in floating storage in Europe, 2015-2022

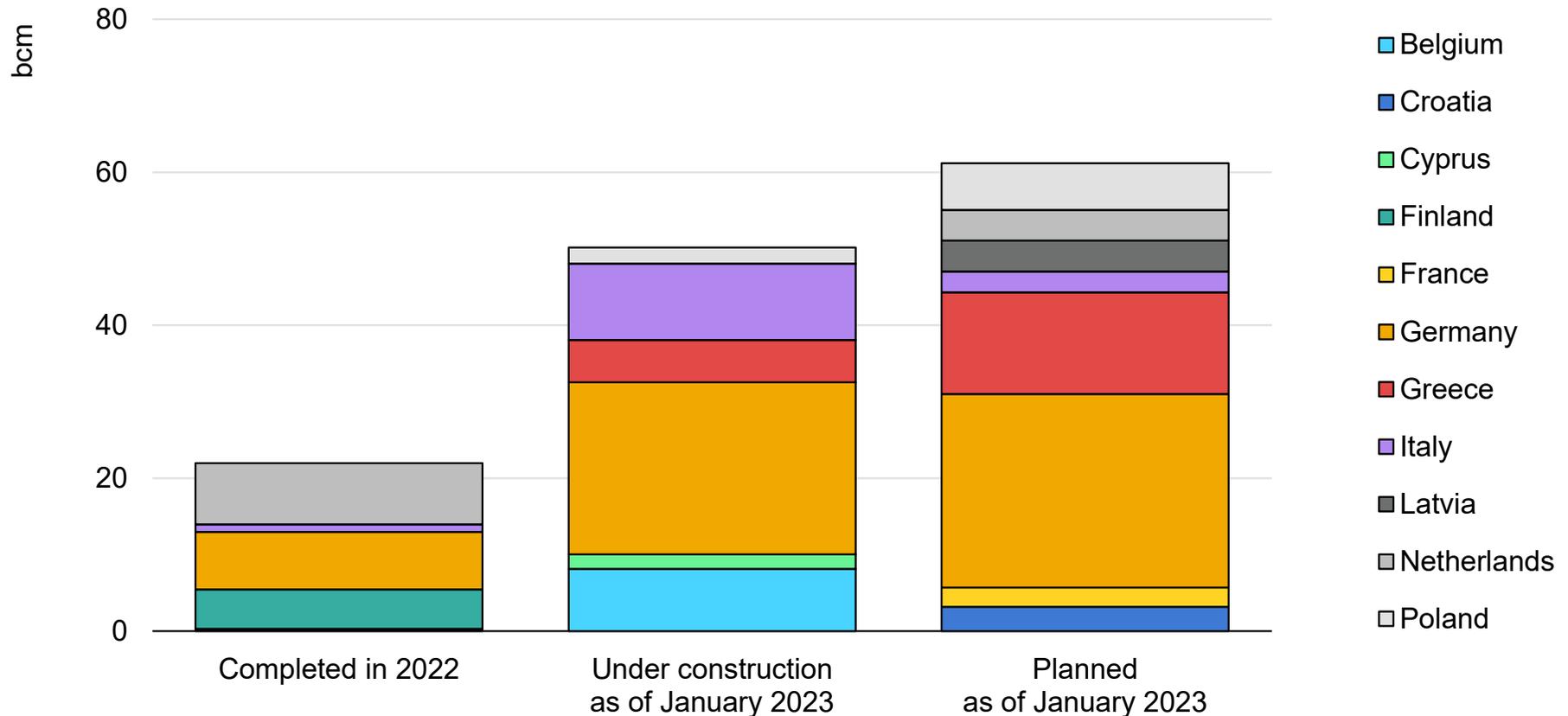


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Source: IEA analysis based on S&P Global Commodity Insights (2023), [Global LNG Floating Storage by Importer](#).

Interest in new LNG import infrastructure has surged within the European Union since the beginning of 2022

New and proposed LNG import capacity additions in the European Union since January 2022

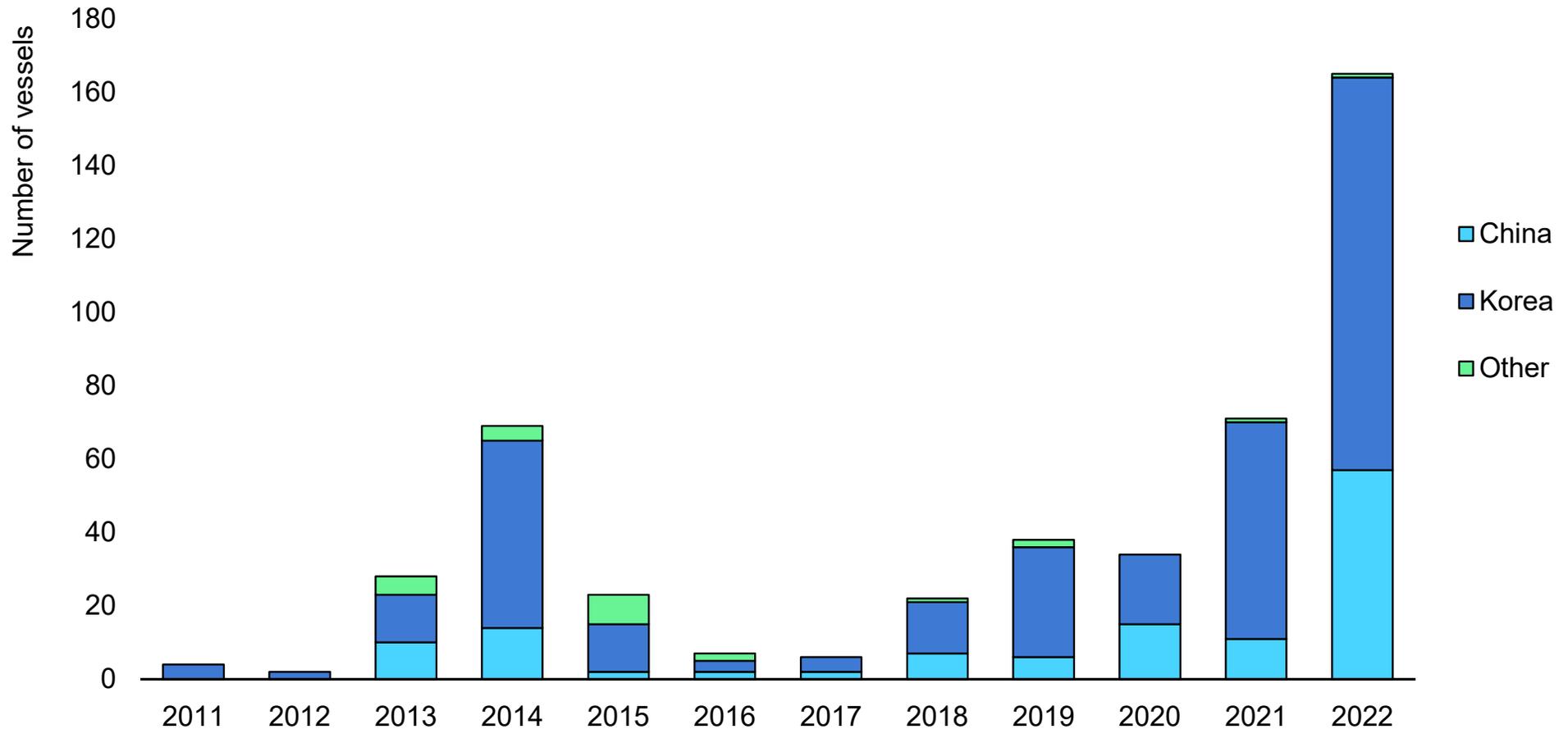


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Sources: IEA analysis based on ICIS (2023), [ICIS LNG Edge](#); S&P Global Commodity Insights (2023), [Global LNG Regasification Capacity](#); Rystad Energy (2023), [Gas Market Cube](#); Cedigaz (2023), [Regasification database](#).

Chinese shipyards accounted for more than a third of LNG carrier orders globally in 2022

LNG carrier orders by builder country



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Source: Refinitiv Eikon (2023), [Shipping data](#).

The value of global LNG trade surged to an all-time high in 2022, amid soaring spot gas prices

Despite rising by a mere 5.5% in volumetric terms, the value of global LNG trade doubled in 2022 to an all-time high of USD 450 billion. The global energy and gas crisis triggered by Russia's invasion of Ukraine drove up spot gas prices and LNG import bills to record levels across key Asian and European markets. Gas and LNG producers' record profits could support additional investment in reducing the emissions intensity of gas value chains, enhancing methane capture efforts and diversifying economic structures to adapt to the new global energy economy that is emerging.

LNG played a critical role in mitigating the impact of Russia's deep cuts in piped gas supply to the European Union and was instrumental in avoiding gas supply shortages in 2022. The stiff competition for flexible LNG cargoes between Asia and Europe provided strong upward pressure on hub and LNG spot prices throughout the year. In Europe month-ahead prices on the TTF averaged over USD 40/MBtu in 2022, almost eight times their five-year average between 2016 and 2020. In Asia LNG spot prices followed suit, averaging at USD 34/MBtu over the year, more than five times their five-year average between 2016 and 2020. Consequently, the estimated value of LNG traded under spot mechanisms – more than doubled to over USD 230 billion.

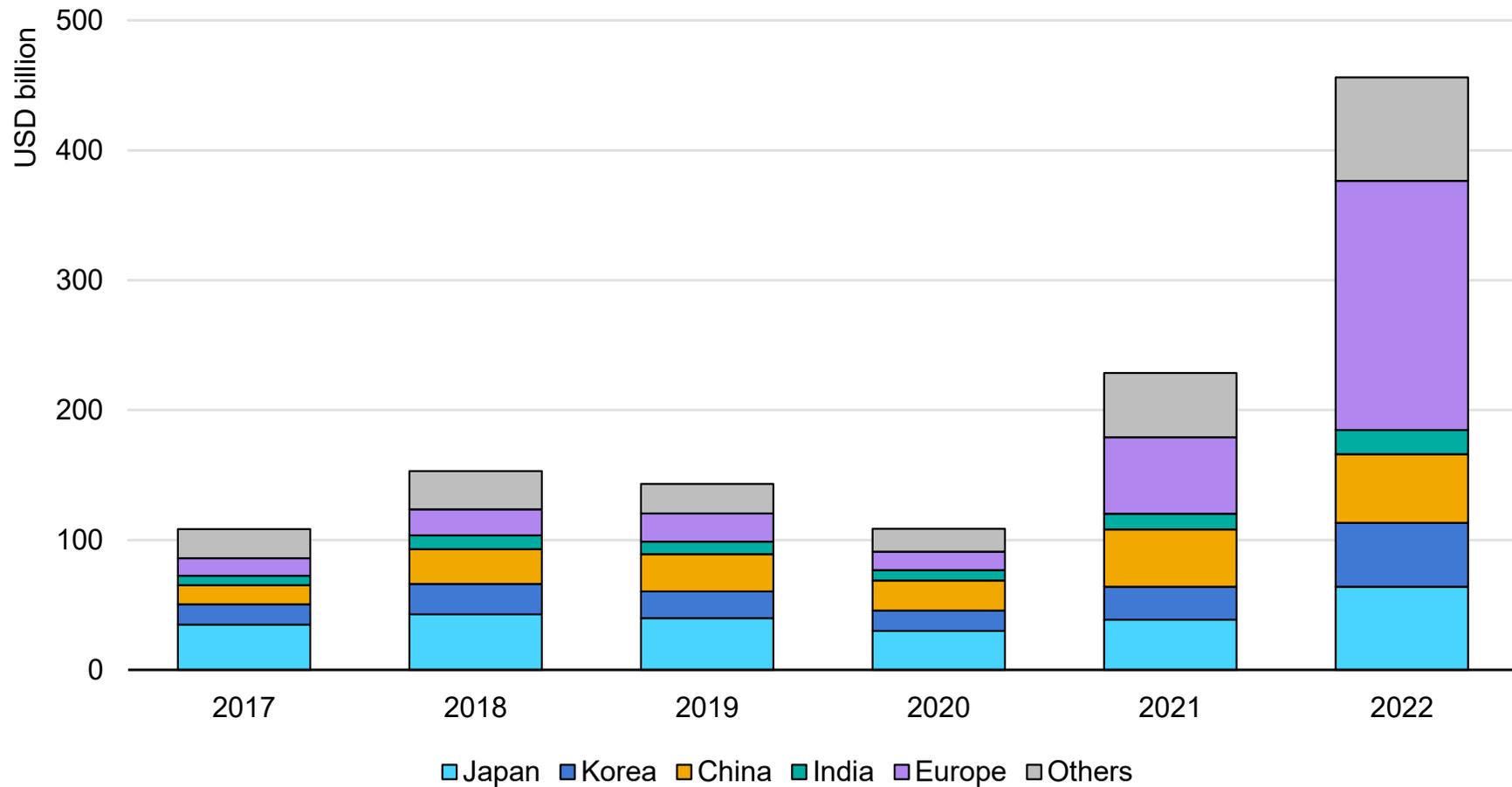
Heightened geopolitical uncertainty and tightening supply drove up oil prices to their highest level since 2013. This in turn placed

upward pressure on oil-indexed LNG contract prices, which rose by 70% in 2022 to an estimated average of USD 15/MBtu. Hence, the value of LNG traded under long-term oil-indexed LNG contracts – approximately 60% of global LNG trade – rose by 90% to an estimated USD 220 billion.

Markets with greater exposure to spot procurement experienced a sharper increase in their LNG import prices. The weighted average import price in Japan and Korea, which rely predominantly on long-term, oil-indexed contracts, rose by 80% to USD 19/MBtu in 2022. In contrast, the import price of the United Kingdom, heavily reliant on spot procurement, almost tripled compared with 2021 to an average of USD 28/MBtu. Europe's LNG procurement costs more than tripled compared with 2021 to an estimated USD 190 billion, and accounted for 60% of the total increase in the global LNG import bill. The region's LNG imports soared by over 60% (almost 70 bcm), while the estimated LNG import price more than doubled. The combined LNG import bill of Japan and Korea rose by 80% to close to USD 115 billion, while LNG imports declined by 2% compared with 2021. The People's Republic of China's (hereafter "China") LNG procurement costs rose by almost 20% to over USD 50 billion, despite a decline of 20% in the country's total LNG imports.

The value of global LNG trade doubled in 2022 to over USD 450 billion

Estimated cost of LNG procurement by key import markets, 2017-2022



Sources: IEA analysis based on various customs data.

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Natural gas supply security takes central stage amid new wave of market reforms in 2022

The global energy crisis triggered by the Russian invasion of Ukraine put gas supply security and market stability at the centre of policy interventions in 2022. They included the introduction of more stringent storage regulations, LNG procurement mechanisms based on enhanced co-ordination, and wholesale market interventions aiming to reduce price volatility.

More stringent storage regulations are central to enhancing seasonal gas supply security

The IEA suggested the introduction of minimum gas storage obligations in the [10-Point Plan to Reduce the European Union's Reliance on Russian Natural Gas](#), published at the start of March 2022. The IEA noted that fill levels of at least 90% of working storage capacity by 1 October would be necessary to provide an adequate buffer for the European gas market through the heating season. The European Union adopted a new storage regulation at end of June 2022, with a target storage fill level of 80% of capacity before the winter of 2022/23, and 90% ahead of all following winter periods. The regulation includes intermediate storage level targets aimed at achieving a more optimal storage cycle through the year. Several EU

member states (including Belgium, France, Germany and Italy) adopted more stringent storage regulations, with fill targets above 90%.

The Ministerial Council of the Energy Community¹ adopted its own Gas Storage Regulation in October 2022. The new rules require those Contracting Parties that have storage – Serbia and Ukraine – to follow a filling trajectory with intermediate targets. According to the filling trajectory adopted in November 2022, Serbia and Ukraine should fill their storage sites to at least 70% and 58% of working capacity respectively by 1 September 2023.

In Japan the government plans to introduce a “Strategic Buffer LNG” (SBL) to boost security of gas supply. The government intends the policy to use the procurement power of private companies to prepare for potential LNG shortage situations. The selected private companies will secure the SBL through term contracts, being amounts beyond those they are assumed to require for their own normal business activities. They can sell the purchased gas into both overseas and domestic markets under normal conditions, while in an emergency SBL will have to be sold to domestic companies that are at risk of supply disruption under the direction of the Ministry Economy, Trade and Industry (METI). Any loss caused by the

¹ The Energy Community has nine Contracting Parties: Albania, Bosnia and Herzegovina, Kosovo, North Macedonia, Georgia, Moldova, Montenegro, Serbia and Ukraine.

transaction is compensated from a fund held by JOGMEC (Japan Organization for Metals and Energy Security) and any profit is returned to the fund. For the time being, the government aims to secure at least one cargo per month as SBL for the winter season, when demand is at its highest in Japan. In the medium term the aim is to increase SBL to one cargo per month throughout the whole year. The new mechanism is expected to be launched in fiscal year 2023/24.

In Singapore, where imported gas is used to generate around 95% of electricity, a Standby LNG Facility was first introduced at the end of 2021 and extended into 2022 by the Energy Market Authority (EMA) to address the risk of gas supply disruptions. Under the crisis measures, which for now expire at the end of March 2023, authorities can order private companies to purchase enough LNG to generate electricity based on their available capacity, as well as to use LNG from the Standby Facility if they do not wish to draw on their own gas reserves.

In China the 14th Five-Year Plan for a Modern Energy System, which was released in March 2022, sets a target to more than double the country's gas and LNG storage capacity to reach 55-60 bcm by 2025. This is equivalent to about 13% of total gas consumption as projected by the National Development and Reform Commission (NDRC). The accelerated buildout of gas storage capacity is aimed at bolstering gas supply security and mitigating the risk of damaging price spikes and fuel shortages, especially during the peak winter months.

Co-ordinated LNG procurement mechanisms can enhance gas supply security, increase bargaining power and enable more sophisticated risk-sharing among companies

In the European Union the Council adopted a regulation in December 2022 to enhance solidarity through the better co-ordination of gas purchases. The Joint Purchasing Mechanism establishes a two-step process to facilitate the procurement of natural gas and LNG:

- Demand aggregation: a service provider, contracted by the European Commission, will collect import requirement data from EU companies and offers from non-Russian gas suppliers and then match them through the organisation of tenders. Participation in demand aggregation will be voluntary, except for volume requirements equivalent to 15% of gas storage filling needs (equalling ~13.5 bcm or 3% of EU gas consumption in 2021), when demand aggregation will be binding.
- Joint purchasing: following the matching of demand with supply, companies can voluntarily conclude contracts with the gas suppliers, either individually or jointly (through consortiums).

As highlighted by the IEA Report on How to Avoid Gas Shortages in the European Union in 2023, the Joint Purchasing Mechanism can increase the bargaining power of EU companies, enable more sophisticated risk sharing in a highly volatile price environment and eventually facilitate the sharing of best practices related to bringing low-emission or wasted gas to market.

Joint gas procurement of gas could have significant added value in Central and Eastern European markets, which historically relied heavily on Russian gas imports. These markets are often relatively small, face logistical issues in sourcing LNG (being landlocked) and have limited experience of LNG procurement and trading.

Besides the European Union, the Joint Purchasing Mechanism is open to the participation of companies from Energy Community Contracting Parties.

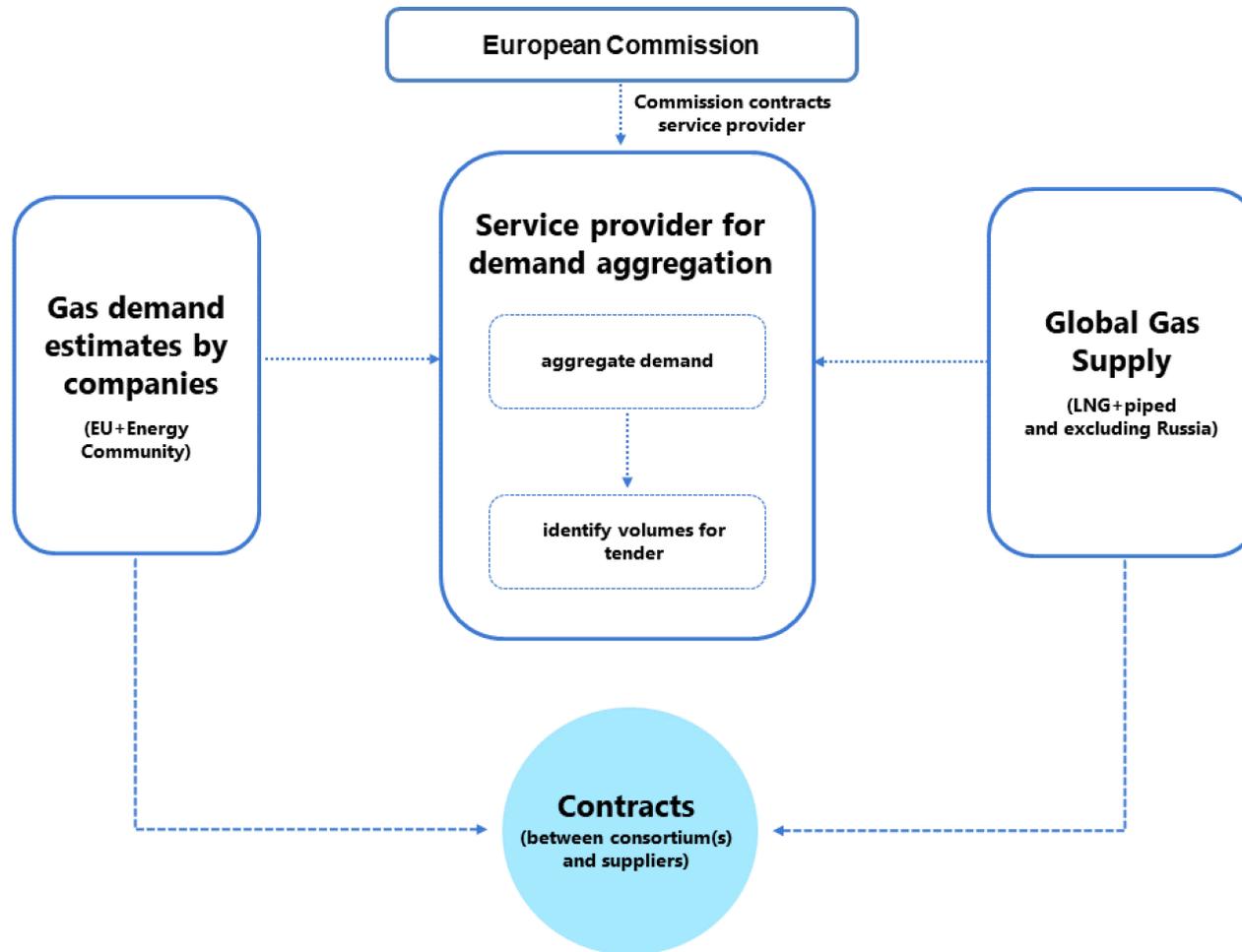
As part of a package of measures to strengthen energy security, Singapore's energy regulator, the EMA, also announced in October 2022 that it will work with industry to aggregate gas procurement and obtain longer-term, more secure contracts, without providing additional details at the time of writing.

Meanwhile, in China the NDRC in October ordered state-owned gas importers to suspend LNG resales to buyers outside China during the winter heating season in a bid to ensure sufficient domestic supplies, even in the event of a cold spell. The NDRC has also facilitated gas supply contracts between city gas distributors and state-owned energy majors ahead of the heating season, and pledged to supervise "strict contract implementation" to secure stable gas supplies during the winter. Though LNG imports continued to slide following the announcements in October, the y-o-y decline during the last two months of 2022 (down 12%) was much shallower than during the first 10 months of the year (down 23%).

In Japan the government aims to further increase its involvement in LNG procurement amid increasing uncertainty regarding supply. The government is introducing new legislation empowering METI to ask JOGMEC to procure LNG when there is, or is likely to be, a problem in securing a stable supply of gas. Principally it assumes that when private companies face difficulties conducting ordinary LNG procurement, JOGMEC will procure instead. This upcoming system would give METI similar legal power in the LNG market to supply the city gas sector as it already has for the power generation sector.

The European Union adopted a Joint Gas Purchasing Mechanism in 2022

Simplified representation of the EU Joint Purchasing Mechanism for gas



Sources: IEA analysis based on European Commission (2022), [EU Energy Platform](#).

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Wholesale market interventions are aimed at reducing excessive price volatility

During 2022 natural gas prices reached all-time high levels in Asian and European markets amid tight market conditions. Record high price levels were accompanied by excessive volatility and short-term price variability.

In the European Union, the Energy Council adopted a temporary market correction mechanism (MCM) in December 2022 to limit excessive price volatility on the European gas hubs. According to the council's decision, the mechanism will apply from 15 February 2023 for a period of one year and will cover derivatives with maturities between one and twelve months traded on exchanges. The MCM does not apply to gas traded OTC via brokerages.

The MCM will be activated where the following two conditions are met simultaneously:

- The month-ahead price on the TTF exceeds EUR 180/MWh for three working days.
- The month-ahead TTF price is EUR 35/MWh higher than a reference price for LNG² on global markets for the same three working days.

² The reference LNG price will be calculated based on: Daily Spot Northwest Europe Marker (administered by Platts Benchmark B.V.); Northwest Europe des – half-month 2 (administered by Argus Benchmark Administration B.V.); Daily Spot Mediterranean Marker (administered by Platts Benchmark B.V.); Iberian peninsula des – half-month 2 (administered by Argus Benchmark Administration B.V.); Italy des – half-month 2 (administered by Argus Benchmark Administration

Once triggered, the mechanism introduces a “dynamic bidding limit”, which equates to the LNG reference price plus EUR 35/MWh. While the mechanism is active, transactions above the “dynamic bidding limit” will not be allowed to take place. Once activated, the MCM stays in place for at least 20 days.

The dynamic bidding limit is automatically deactivated where either of the following conditions is met:

- The dynamic bidding limit is below EUR 180/MWh for last three consecutive working days.
- The European Commission declares a regional or a Union emergency.

The regulation includes strong safeguard measures. Accordingly, the European Commission can suspend the mechanism if unintended market disturbances occur, which negatively affect security of supply, intra-EU flows or financial stability. They include developments such as:

- A strong increase in natural gas demand (up by 15% in one month or 10% in two consecutive months compared with historic averages for the given period).
- A significant decrease in LNG imports.

B.V.); Greece des – half-month 2 (administered by Argus Benchmark Administration B.V.); LNG Japan/Korea DES 2 Half-Month (administered by Platts Benchmark B.V.); Northeast Asia des (ANEA) – half-month (administered by Argus Benchmark Administration B.V.); the front-month NBP derivative settlement price, as published by ICE Futures Europe and ACER's own LNG benchmark.

- A significant decrease in traded volume on the TTF compared with the same period a year ago.
- The MCM affecting the validity of existing gas supply contracts.

In mid-December 2022 the Australian government introduced a 12-month price cap of AUD 12/GJ (approximately USD 8.5/MBtu) on new domestic gas contracts with east coast producers to help keep wholesale gas contract prices under control. According to Australian Competition and Consumer Commission analysis, about two-thirds of the production of natural gas from the east coast of Australia is exported overseas under long-term contracts. Excess volumes are also produced that are not contractually committed, which means that they can be supplied into either the domestic market or the international LNG market. This price cap mechanism could lead gas producers to divert most of their excess gas to overseas spot markets, and the domestic market could then face a supply shortfall in the future. The cap is intended to be reviewed in mid-2023 to assess the impact on contracting behaviour.

Despite some concerns from independent east coast LNG producers about investment in new gas supplies, the Australian government has ensured that this emergency and temporary measure will not apply to gas from undeveloped fields, gas sold on short-term markets, or contracted sales under existing and long-term foundational contracts with international trading sellers. This

measure is unlikely to have any immediate impact on LNG export commitments or contracts.

In addition to the price cap, the new legislation has “a mandatory code of conduct to address systemic issues within the market and guide behaviour, which includes a reasonable price provision”. Under this provision, gas producers and consumers will be able to negotiate gas contracts at “reasonable prices” to reflect the cost of production and a reasonable return on capital. This provision will remain in place until price and domestic gas supply objectives are met. The legislation can be considered as a permanent measure allowing future market intervention.

Gas market update and short-term forecast

North American natural gas demand fully recovered its 2020 losses, with estimated growth of over 4% in 2022

Preliminary data indicate a 4.4% rise in natural gas consumption in North America during 2022. This increase is primarily attributed to substantial consumption growth in the US power generation sector, as well as the expansion in Canadian consumption reported by both power generators and industrial consumers.

Natural gas consumption in the **United States** experienced notable growth of 5.4% in 2022 compared with 2021, fully recovering from the 2020 Covid-induced losses and increasing by close to 3% compared with 2019. This increase was largely due to the power generation sector (up 7%) and the residential and commercial sector (up 6%), which were bolstered by colder than average temperatures during the heating season, as well as several heatwaves during the summer, which necessitated additional gas-fired power for cooling. In 2022 the industrial sector saw a year-on-year increase of 3%, mainly due to the growth of the bulk chemicals industry. Below-normal temperatures in Q4 2022 fuelled an increase in demand for natural gas for heating. In December 2022 the United States was subject to winter storm conditions, including blizzards and a consequential cold wave that augmented the demand for natural gas in the residential, commercial and power sectors.

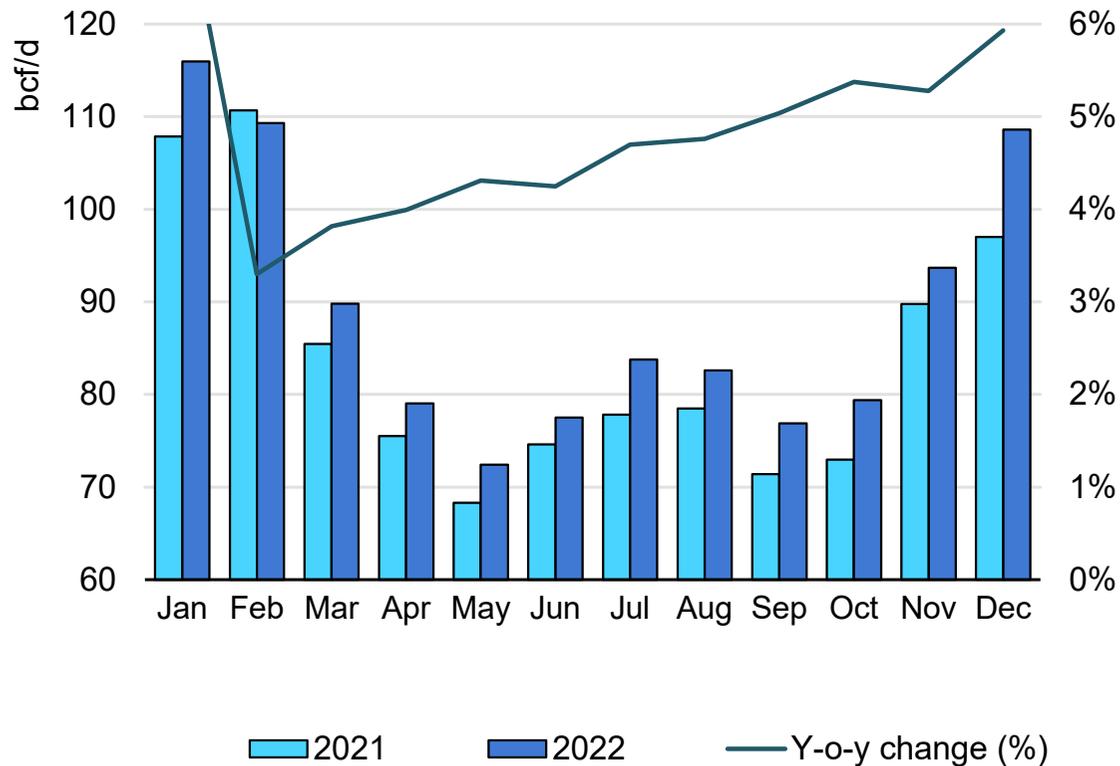
In **Canada** natural gas consumption rose by 7.8% y-o-y in the first ten months of 2022, essentially due to higher demand from wholesale industrial customers and power generators, which was a direct result of the coal phase-out policy in Alberta, in addition to colder than average weather. Retail sales also saw a 6.7% increase y-o-y, rebounding from the contraction experienced in 2021. Lastly, pipeline exports to the United States maintained their expansion seen since 2020, with 7.9% growth y-o-y in 2022.

Mexico's observed natural gas consumption saw a 1.3% decrease in the first 11 months of 2022, with diminished pipeline imports from the United States. Production levels remained relatively static during the same period.

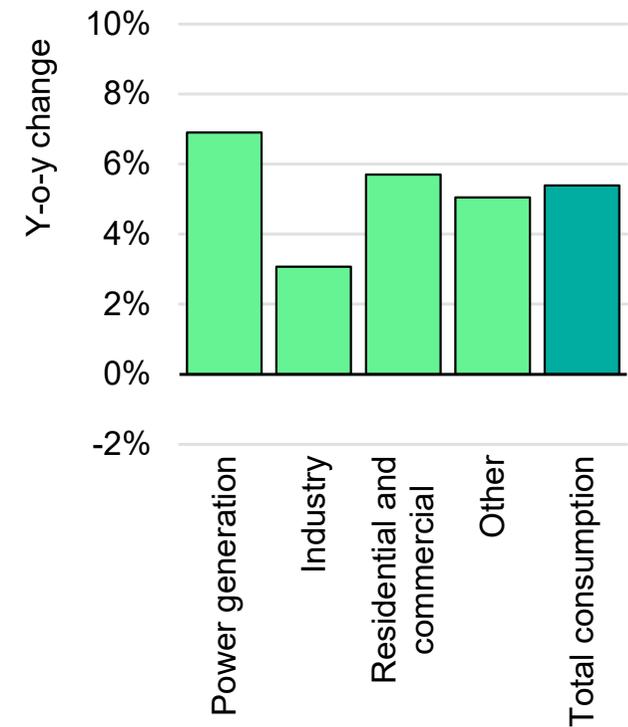
Natural gas consumption in North America is forecast to decline by more than 2% in 2023, principally driven by lower gas use in the power sector on a combination of slightly negative electricity demand growth and the continuous development of renewable electricity capacity. Prices are likely to have an adverse influence on natural gas demand, thereby sustaining the transition away from gas in the power generation sector, with weather conditions comparatively less advantageous to heating and cooling in comparison to 2022.

US gas consumption jumped by over 5% in 2022, supported by power generation and residential uses

Gas consumption by month, United States, 2021 and 2022



Gas consumption by sector, United States, 2022 relative to 2021



Note: bcf/d = billion cubic feet per day.

Sources: IEA analysis based on EIA (2023), [Natural Gas Consumption](#); [Natural Gas Weekly Update](#).

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Gas consumption fell only slightly in Central and South America in 2022 despite a steep drop in Brazil; a further decline from the power generation sector is expected in 2023

We estimate that natural gas demand in the South and Central America region declined by close to 3% in 2022 as a whole, on a combination of higher hydro availability for power generation compared with 2021, and some impact of high prices for LNG-importing markets. It is forecast to stabilise in 2023 on the assumption of normal temperature and rainfall conditions.

Gas consumption in **Argentina** declined by an estimated 1% y-o-y during the first eleven months of 2022. This was due to an 18% decline from the power generation sector, which saw a modest 3% growth in electricity demand and an increase in hydro generation that contributed to reducing the call on gas compared with 2021. This sharp decline was partially balanced by demand growth from other sectors, including industry (up 2%), residential and commercial (up 8%) and transport (up 2%). This growth was supported by rising domestic gas production, which saw a 7% y-o-y increase in 2022 with the development of Neuquén's Vaca Muerta shale formation. Further production growth and infrastructure debottlenecking – particularly the planned commissioning of the first leg of the Nestor Kirchner pipeline in June – are expected to support Argentina's gas consumption in 2023. We forecast growth of close to 4%, principally driven by power generation.

Brazil's natural gas consumption steeply declined in the first ten months of 2022 compared with the previous year, with an estimated 21% fall in apparent consumption. The power generation sector was the main driver behind this change, due to the strong recovery of hydro reservoirs after the exceptional droughts experienced in 2021. According to operational data, total electricity generation increased by only 10 TWh y-o-y (up 2%) January through to December, while hydroelectricity generation rose by close to 64 TWh (up 18%). As a result, thermal generation dropped by 64 TWh (down 53%), with gas-fired generation taking the bulk of the impact with a 45 TWh decline (down 65%). Gas use in the energy sector saw a slight 1% decline in the first ten months of 2022, principally due to a 10% y-o-y drop in refineries' gas consumption. Industrial and retail customers posted 8% and 7% growth respectively over the same period. Gas use is expected to further decline in 2023 as output from hydro and other renewables further squeezes gas out of the electricity generation mix, while high prices keep a lid on consumption in the industrial sector. We forecast an overall decline of 5%.

Natural gas consumption trends are more mixed for other countries in the region. **Trinidad and Tobago** was the region's third largest gas consuming country in 2021 at about 18 bcm, and is estimated to remain stable in 2022 on reportedly less than 1% y-o-y growth in

January through to November. Domestic gas production, which had been on a declining trend since 2019, recorded a 7% y-o-y increase in the first eleven months of 2022, which enabled a rebound in Trinidad and Tobago's LNG exports.

Venezuela reported a remarkable 35% y-o-y increase in its observed gas consumption during the first five months of 2022. This rebound, if confirmed for the whole year, would restore the country's gas consumption to close to its 2019 level. The country showed optimistic signs in late 2022 regarding its upstream oil and gas capacity: the United States granted authorisation to oil major Chevron to resume limited production activity in the country; talks began on potential pipeline exports to Colombia; and discussions may begin on a longer-term project to connect the stalled offshore Dragon gas field to Trinidad and Tobago's LNG export facilities.

Gas consumption in **Colombia** grew by an estimated 5% in 2022. All consuming sectors showed a positive trend except for compressed natural gas sales for vehicles (down 1% y-o-y). Growth was principally driven by the industrial sector (up 7%, with petrochemicals up 13%) and energy sector own use (up 7%, driven by higher consumption for refining).

Apparent gas consumption in **Peru** reportedly increased by 23% y-o-y in 2022, supported by a rebound in electricity demand and gas

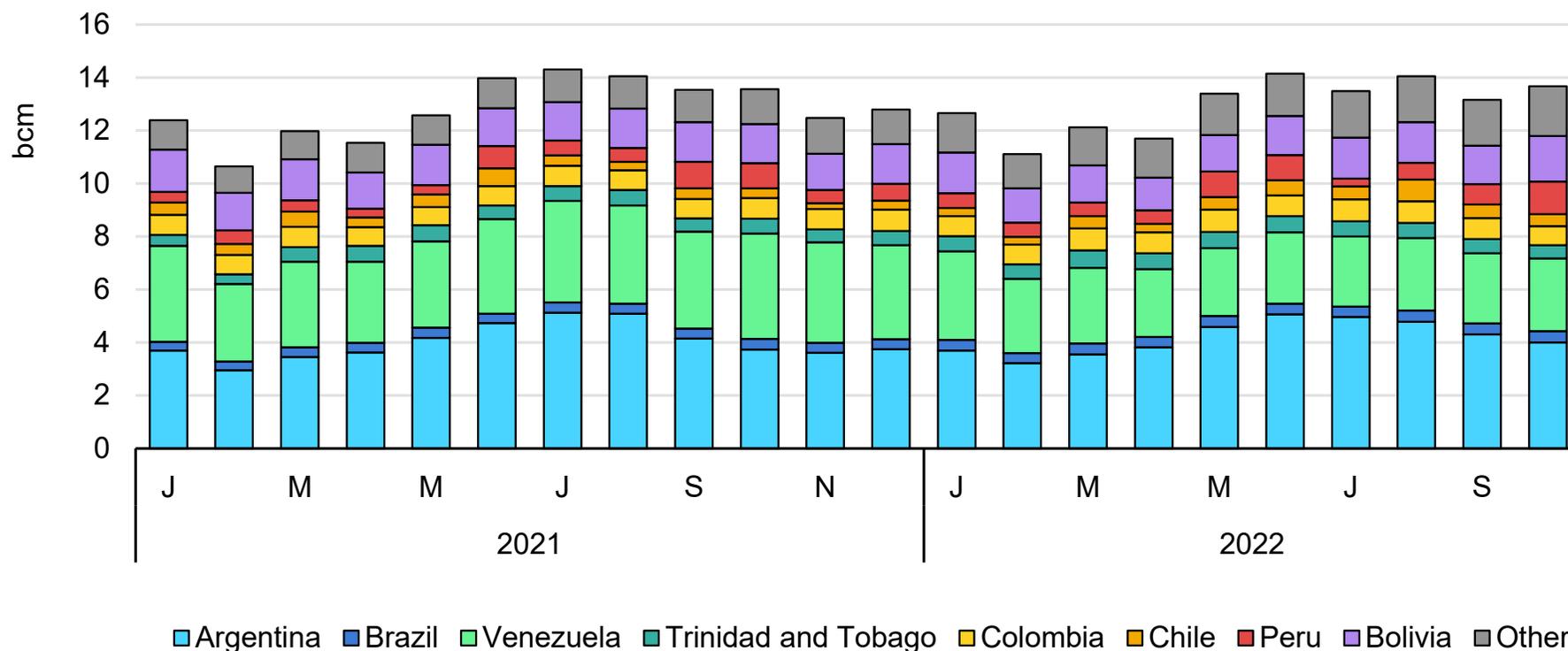
use in the energy sector, as the country ramped up its LNG exports by close to 40% compared with 2021.

In **Chile** gas consumption increased by a reported 10% y-o-y in the first eleven months of 2022. This was driven by the power generation sector, which saw its gas consumption grow by a strong 30% y-o-y during the first 11 months of 2022, supported by a 3% increase in total electricity demand and a 22% drop in coal-fired generation over the same period.

Apparent gas consumption rose in **Central America and the Caribbean** in 2022 as LNG imports increased by 20% y-o-y, mainly supported by the ramping up of imports in Jamaica and Panama (both up 64%), while the Dominican Republic was close to stable (up 5%) and Puerto Rico dropped by 18%.

The drop in Brazil’s gas consumption in 2022 was almost offset by increases in other Central and South American markets

Monthly natural gas demand and production, Central and South America, 2021-2022

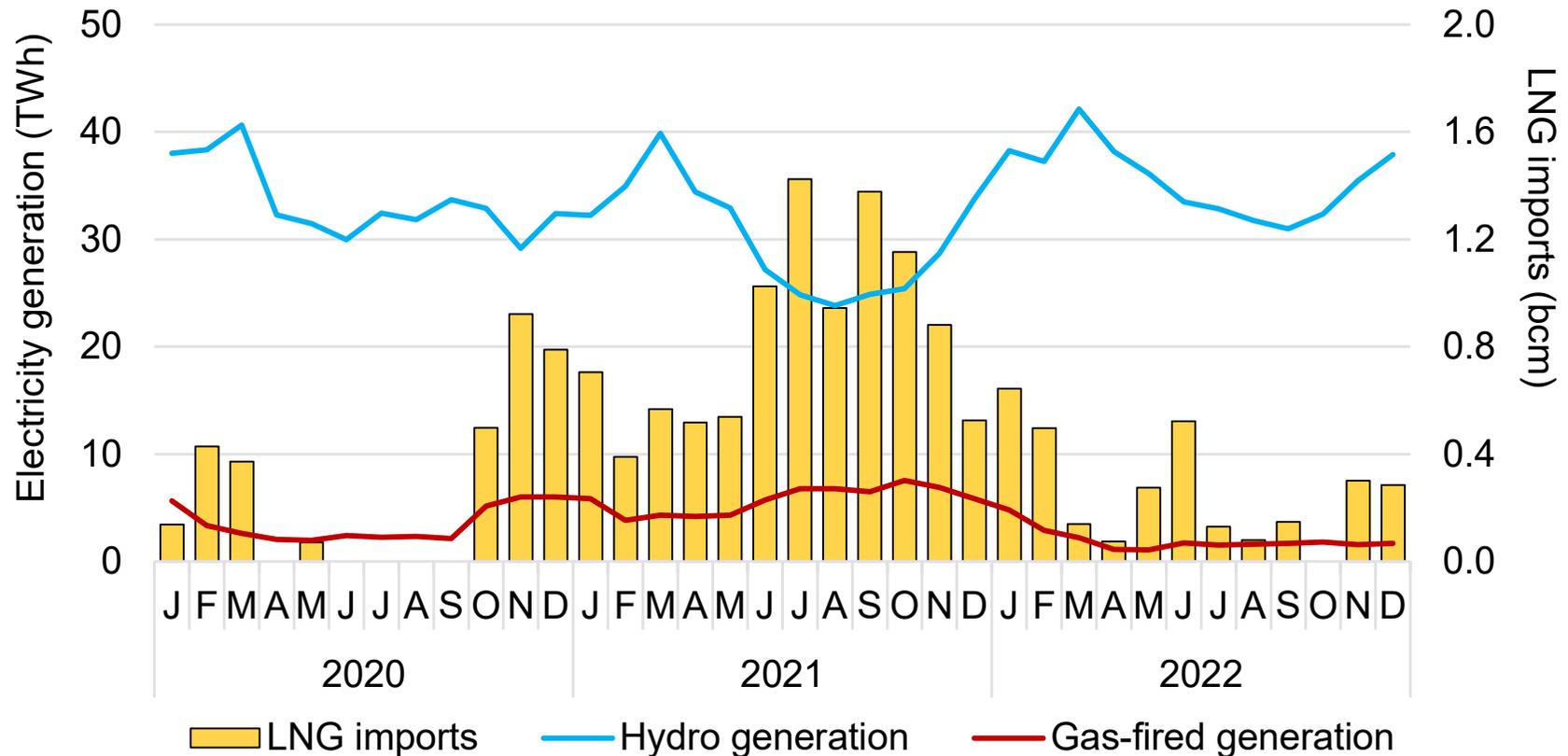


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Sources: IEA analysis based on ANP (2023), [Boletim Mensal da Produção de Petróleo e Gás Natural](#); BMC (2023), [Informes Mensuales](#); Central Bank of Trinidad and Tobago (2023), [Statistics](#); CNE (2023), [Generación bruta SEN](#); ENARGAS (2023), [Datos Abiertos](#); ICIS (2023), [ICIS LNG Edge](#); IEA (2023), [Monthly Gas Data Service](#); JODI (2023), [Gas Database](#); MME (2023), [Boletim Mensal de Acompanhamento da Indústria de Gás Natural](#); OSINERG (2023), [Reporte diario de la operación de los sistemas de transporte de gas natural](#).

Gas use for power generation slumped in Brazil in 2022, after strong demand in 2021 driven by all-time record droughts

Evolution of monthly hydro and thermal electricity production and LNG imports, Brazil, 2020-2022



IEA. CC BY 4.0.

Sources: IEA analysis based on EPE (2023), [Monthly Review of the Electricity Market](#); ICIS (2023), [ICIS LNG Edge](#); ONS (2023), [Power Generation](#).

European gas demand recorded its steepest drop in history in 2022...

Natural gas consumption in OECD Europe fell by an estimated 13% (over 70 bcm) in 2022 – its steepest decline in absolute terms in history. Record high gas prices led to an unprecedented reduction in gas demand in industry, while milder weather conditions weighed on distribution network-related demand. Over 40% of the reduction in annual demand was concentrated in Q4, when natural gas consumption fell by an estimated 20% (33 bcm) y-o-y.

Distribution network-related demand fell by 15% (34 bcm) in 2022, accounting for almost half of the total reduction in OECD Europe's gas consumption. Milder weather conditions weighed on space heating requirements, while record high prices incentivised fuel-switching, energy efficiency measures and conservation efforts in the residential and commercial sectors. Q4 2022 saw distribution network-related demand fall by an estimated 20% y-o-y. Unseasonably mild temperatures in October and the first half of November delayed the start of the European heating season by almost a month and led to a steep 30% y-o-y reduction in distribution network-related demand during these months. The short-lived cold spell in the first half of December temporarily increased residential and commercial demand to above 2021 levels, although it was insufficient to reverse the overall demand trend.

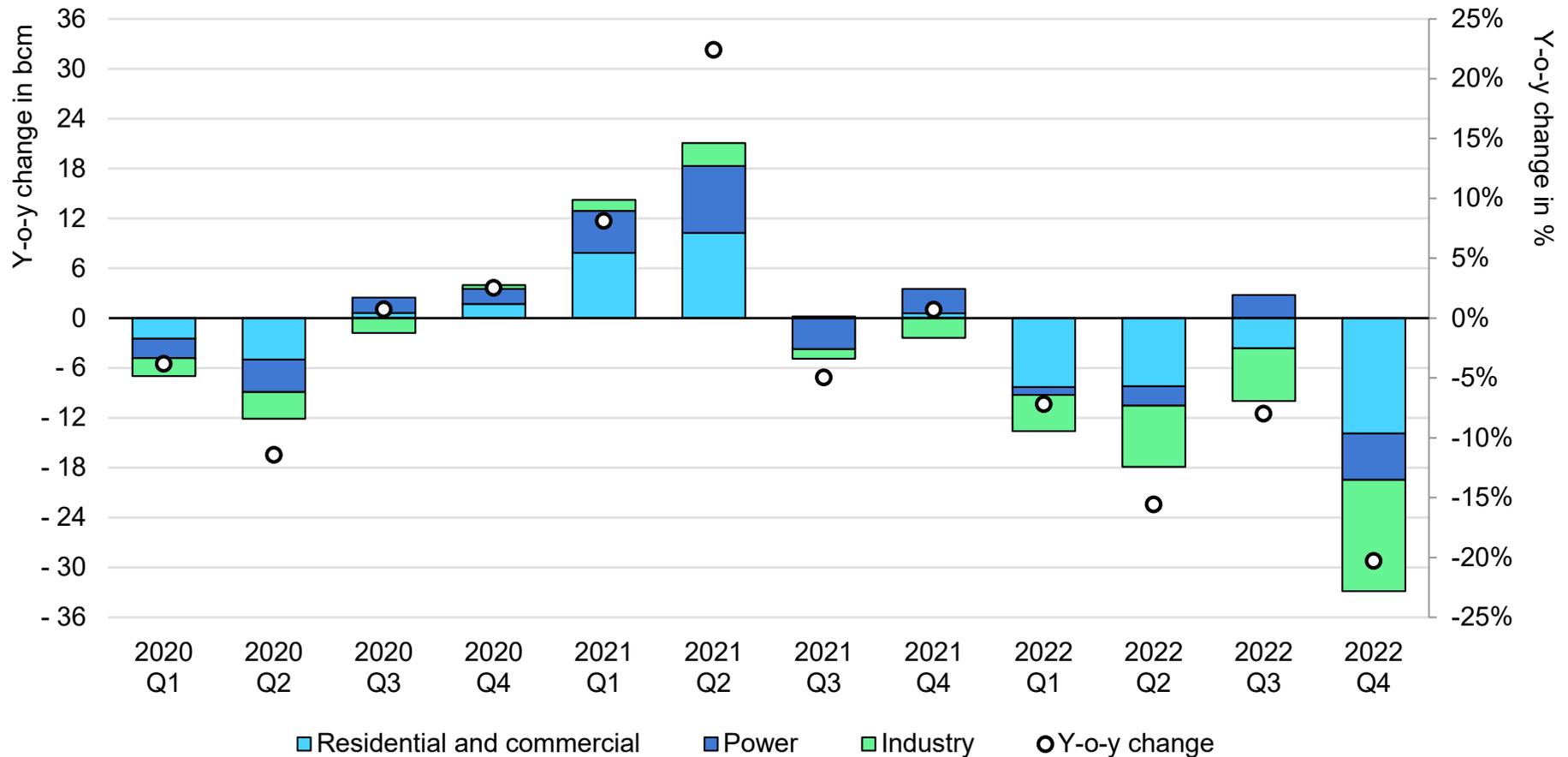
Gas-to-power demand fell by an estimated 4% (6 bcm) in 2022. Despite record high gas prices, gas-fired power generation

remained resilient during Q1-3 2022, as decade-low hydro and nuclear generation provided additional market space for gas-fired power plants. In contrast, gas-fired generation declined by over 10% y-o-y in Q4 amid lower electricity demand, strong wind power output and continued gas-to-coal switching. Gas demand in industry fell by close to 20% (30 bcm) in 2022, with all-time high gas prices driving fuel-switching and leading to production curtailments across the most gas- and energy-intensive industries. The steepest declines in industrial gas demand were recorded the second half of 2022, with a drop of 25% y-o-y.

OECD Europe's gas demand is forecasted to decline by 3% in 2023. This is largely driven by lower gas burn in the power sector, down by close to 15% amid rapidly expanding renewables and improved nuclear availability in France. Industrial sector gas demand is expected to recover by close to 10%. In contrast, a return to average temperature conditions would increase residential and commercial demand by 3%. Assuming the complete cut-off of Russian piped gas supplies and a tighter global LNG balance, steeper demand reduction of 8% would be needed in the European Union, as highlighted in the IEA report [How to Avoid Gas Shortages in the European Union in 2023](#).

...declining by over 70 bcm in 2022 amid mild weather and demand reduction in industry

Estimated quarterly change in gas demand, OECD Europe, 2020-2022



IEA. CC BY 4.0.

Sources: IEA analysis based on Enagas (2022), [Natural Gas Demand](#); ENTSOG (2022), [Transparency Platform](#); EPIAS (2022), [Transparency Platform](#); Trading Hub Europe (2022), [Aggregated consumption](#).



Asian gas demand came under pressure in 2022; recovery in 2023 is expected to be modest

Asia's gas consumption decreased by an estimated 2% in 2022 as a result of high LNG prices, Covid-related disruptions in China and mild weather during most of the year in Northeast Asia. This represents a sharp reversal from 2021, when gas demand rose by a robust 7% as the region's economies recovered from the Covid-related shock of 2020. Asian gas demand is projected to return to modest growth of around 3% in 2023 thanks to the lifting of China's zero-Covid policy, an assumption of normalising weather and the modest recovery of India's and Emerging Asia's gas consumption after steep declines in 2022.

China's gas consumption decreased by nearly 1% in 2022 according to the latest data from the Chongqing Petroleum and Gas Exchange; the NDRC reported a 1.7% drop for the same period. Last year's demand decline was the combined result of slowing economic growth, price-driven demand destruction and widespread lockdowns under China's strict zero-Covid policy. It represented the first annual decline in Chinese gas consumption in four decades. The biggest drop in demand came from the power sector, where record growth in renewable output and a robust increase in coal-fired generation squeezed gas-fired plants in the electricity mix. Combined consumption in industry and the energy sector registered a small decline as a result of high prices and Covid-related disruptions, while the city gas segment experienced modest expansion thanks to growing gas penetration and weather effects (with heating degree days nationwide up by 16% and cooling

degree days up by 1% compared with 2021). In 2023 China's gas consumption is projected to see a nearly 7% rebound, led by the industrial sector. The 2023 demand increase is fuelled by the expected recovery of economic activity following the easing of Covid-19 lockdown restrictions and China's diminishing exposure to high and volatile spot LNG prices thanks to its newly signed LNG contracts. These offer LNG at an average price of less than USD 15/MBtu, substantially lower than recent prices on the spot market. According to our database, about 13 bcm of new LNG contracts are scheduled to start delivering in 2023 alone.

India's gas consumption is estimated to have declined by 6% in 2022 as high prices squeezed gas demand for power generation (down 24% y-o-y), refining (down 30% y-o-y) and the petrochemicals sector (down 32% y-o-y) in particular. City gas demand was broadly flat, while consumption in the fertiliser segment and other end uses (which include agriculture, upstream operations and other industries) saw modest expansion throughout 2022, although they were not enough to compensate for the steep declines in the more price-sensitive sectors of the economy. India's LNG imports dropped by 17% in 2022, the steepest fall on record and the first decline covering two consecutive years in India's two-decade history as an LNG importer. Price-driven fuel-switching played the leading role in suppressing LNG demand, but a modest 3% increase in domestic production also contributed to the decrease in LNG inflows. In 2023 total gas consumption is expected

to increase by 4% thanks to a modest recovery in power sector gas use and continuing – albeit slow – growth in the industrial and city gas sectors.

Japan's total gas consumption declined by just under 1% in 2022 according to our estimates. Higher consumption in the commercial and industrial sectors – driven by Japan's ongoing economic recovery – were offset by continuing declines in gas use for power generation. In the first eleven months of 2022 gas demand was almost flat, while city gas sales for commercial and industrial users increased by 7% and 3%, respectively, according to data from METI. Nuclear output was down by nearly 16% y-o-y during the same period, but soaring gas prices meant that gas-fired generators played only a secondary role in filling the shortfall. In 2023 total gas consumption is projected to decrease by nearly 4% as growing solar and nuclear generation reduce power sector gas use even further. Higher nuclear output is driven by the expected restart of at least two additional reactors and improving operating rates at the ten units that have already restarted since Fukushima.

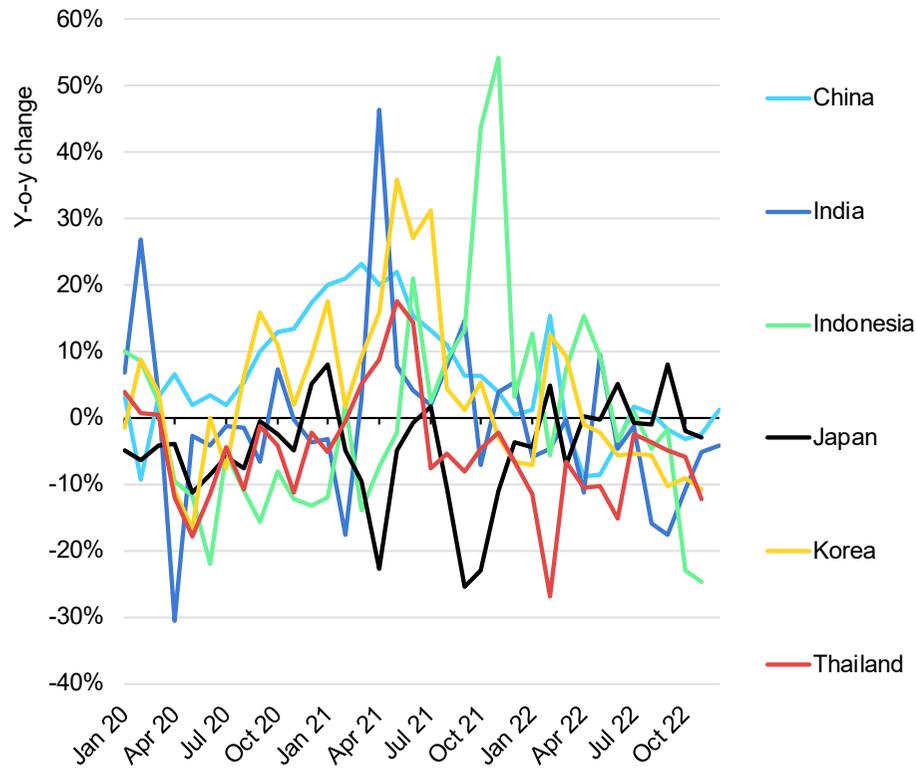
Korea's gas consumption decreased by an estimated 2% in 2022, as higher nuclear and renewable output (combined with strong coal-fired generation in the first half of the year) squeezed gas use in the power sector. Detailed sector-level data from the Korea Energy Economics Institute indicate that gas demand in the city gas segments saw robust y-o-y growth of 4% during the first ten months of 2022, but this could only partially offset a 5% y-o-y decline in power sector gas use over the same period. Gas demand in 2023 is set to decrease by another 2%, driven by the start-up of 2.8 GW of new coal-fired capacity, the late-2022 restart of the 1 GW Hanbit 4

nuclear unit after an extended safety check lasting for more than five years, and the commissioning of the 1.4 GW Shin Hanul 1 nuclear block scheduled for H2 2023. Growing industrial and city gas demand will partly offset the reduction in gas use for power generation.

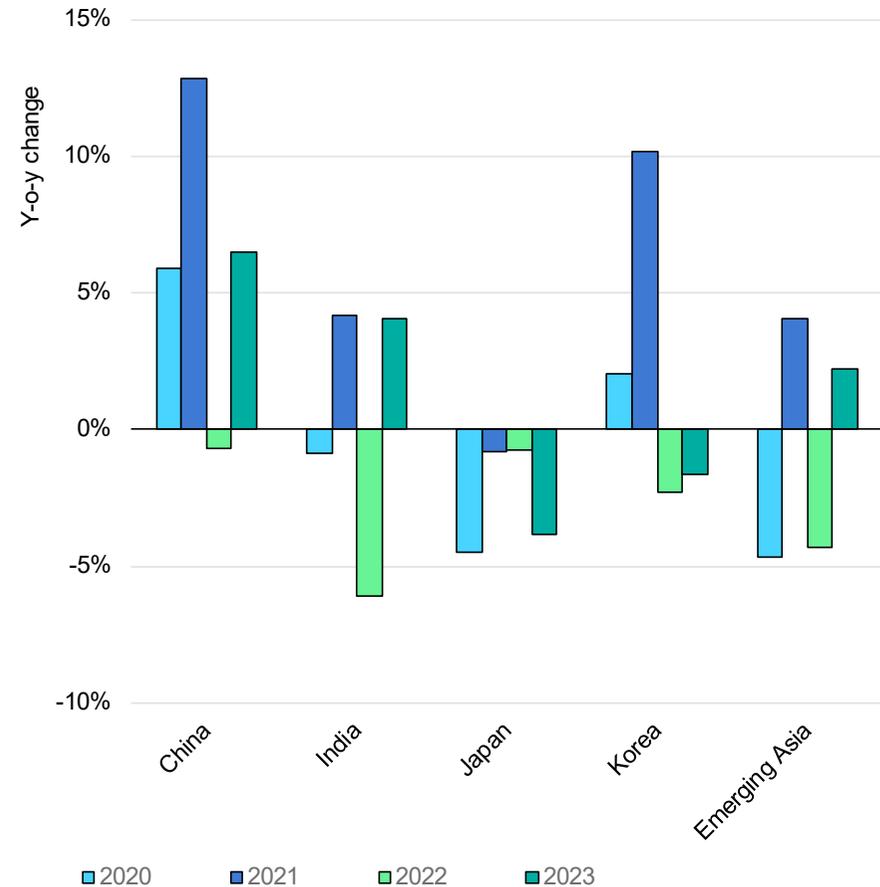
Emerging Asia's gas consumption dropped by an estimated 4% in 2022, as high import prices combined with falling domestic supply from some of the region's legacy producers put pressure on demand. Thailand, the region's biggest gas consumer, recorded a 10% y-o-y drop in its gas use during the first eleven months of 2022, with most of the decline concentrated in the power sector and the domestic energy industry. Indonesia, the number two consumer in emerging Asia, saw an overall 3% y-o-y decrease in the first eleven months of the year. Y-o-y readings turned mostly negative from mid-2022, and gas demand was down by 12% in the July to November 2022 period (with power and industry both contributing to the decline), a sharp contrast to the 6% y-o-y growth recorded in H1 2022. Gas demand was also severely curtailed in Pakistan and Bangladesh due to a combination of power cuts and switching to alternative fuels as spot LNG became all but unaffordable for the two South Asian importers. In 2022 LNG imports into Pakistan and Bangladesh dropped by 18% and 17%, respectively, the sharpest annual decline in both countries' brief history as LNG importers. In 2023 the region's gas consumption is projected to increase by a modest 2%, fuelled by growing economic activity and power demand. However, total consumption in emerging Asia would still remain 7 bcm lower than the 2019 peak, which was followed by steep declines in both 2020 and 2022.

Widespread 2022 demand declines in Asia are set to be followed by an uneven recovery in 2023

Monthly gas demand, selected Asian countries, 2020-2022



Gas demand, selected Asian countries, 2020-2023



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Sources: IEA analysis based on ICIS (2023), [ICIS LNG Edge](#); CQPGX (2023), [Nanbin Observation](#); JODI (2023), [Gas World Database](#); PPAC (2023), [Gas Consumption](#); EPPO (2023), [Energy Statistics](#), Korea Energy Economics Institute (2023), [Monthly Energy Statistics](#), Ministry of Economy, Trade and Industry of Japan (2023), [METI Statistics](#).

US natural gas production growth in 2022 was primarily supported by oil-driven assets, while output from pure gas-driven plays saw a limited increase

US natural gas output increased by an estimated 3.8% in 2022 in a context of rising demand from both domestic and export markets, despite exploration and production players continuing their conservative financial guidance on spending. The bulk of this growth was supported by associated gas production from the Permian Basin and other oil-driven shale plays, which together saw an increase in natural gas output of 10.4% y-o-y, while production from gas-driven shale plays increased by a modest 0.9% (and declined in the leading Appalachian Basin).

Natural gas drilling activity jumped during the first half of 2022, from 105 active rigs in early January to an average of 154 in July. This growth rate slowed during the summer to reach a peak of 166 gas rigs by mid-September (its highest level since August 2019); activity then experienced a slow decline over the fourth quarter to reach an average of 154 active rigs in December.

In the leading Appalachian Basin drilling activity reached an average of 93 wells per month in 2022, compared with 70 in 2021 (up 31% y-o-y), with a notable increase during the year from an average of 86 per month in the first quarter to 100 in the fourth quarter. The number of well completions was higher on average than the drilling numbers in 2022, which led to a slight decline in the

number of drilled but uncompleted (DUC) wells, which dropped from 671 units in January to 621 in December. In spite of this strong drilling and completion activity, dry gas production from the Appalachian Basin declined by an estimated 4.8% y-o-y in 2022, with some recovery as the year progressed compared with a 5.5% y-o-y drop in the first quarter. This underlines a decline in well productivity that may be related to lower drilling activity in the basin's core areas. The Marcellus play, which accounts for over 80% of the Appalachian Basin's output, maintained almost stable production in 2022 compared with 2021, whereas the Utica play experienced a 21% y-o-y drop in 2022. Lack of additional pipeline takeaway capacity is understood to be one of the drivers behind this slowdown, as five out of six pipeline projects designed to debottleneck the Appalachian Basin's gas export capacity have been cancelled over the last five years; the remaining one – the Mountain Valley Pipeline project – is still awaiting permit approval.

Activity in other gas-driven basins was more positive, with a strong 18% y-o-y increase recorded in the Haynesville play in 2022. The Haynesville, which is located across the states of Arkansas, Louisiana and Texas, benefits from close access to the Gulf Coast and its LNG export plants.

Natural gas output from oil-driven shale plays benefited from rising light tight oil production, which increased by an estimated 620 kb/d in 2022. In the Permian Basin, the largest associated gas-producing shale play and the second largest gas-producing basin after the Appalachian, daily average tight oil output increased by 14% in 2022, while associated natural gas production grew by 17% over the same period. Drilling activity in the Permian Basin surged by 50% y-o-y in 2022, the number of drilled wells increasing during the year from 341 in January to 432 in December. The monthly well completion rate remained above drilling numbers, resulting in a reduction in the DUC count from 1 381 in January 2022 to 1 069 in December. Drilling activity also moved to higher associated gas areas within the Permian Basin, which contributed to the increase in the average gas to oil ratio (GOR) of Permian production.

Associated gas production also increased – albeit more modestly – in the Mississippian (up 11% y-o-y), Eagle Ford (9%), Woodford (8%) and Bakken (1%) plays, while remaining stable in the Niobrara and declining in the Fayetteville (down 6%).

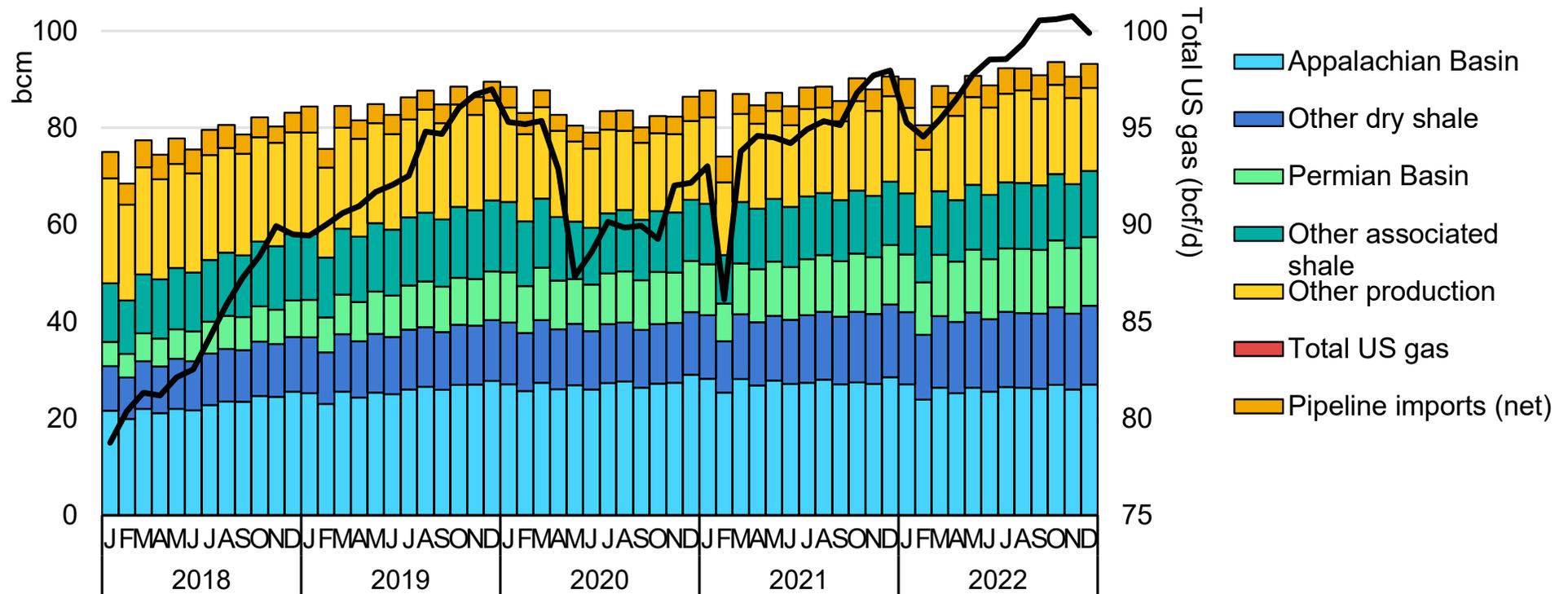
Conventional gas production from both onshore and offshore assets is estimated to have increased by close to 2% in 2022, also principally driven by the growth in associated gas output from higher oil production.

US natural gas production is expected to see more limited growth in 2023, after several years of low investment driven by strict financial guidance from oil and gas companies. Higher returns in 2022 do not seem to herald any major change in spending targets while companies keep a strong focus on short-term shareholder returns. EQT Corporation, a major US natural gas producer, reported in late 2022 a doubling of its share repurchasing programme to USD 2 billion and a near doubling of its debt reduction target from USD 2.5 billion to USD 4 billion for 2023. Other leading gas producers Antero Resources, Southwestern Energy and Chesapeake Energy have collectively repurchased close to USD 3 billion of their shares in 2022.

Limited prospects for an increase in spending, together with cost inflation, workforce shortages and a risk of further productivity declines as drilling is less concentrated in core areas, are likely to slow the rate of gas production growth in 2023 compared with previous years. Our forecast expects US natural gas output to increase by about 2% this year, principally supported by associated gas production, while pure gas shale plays are expected to see only limited growth.

US natural gas production reached new records in 2022 in spite of limited growth from pure shale gas plays

Gas production by type, United States, 2018-2022

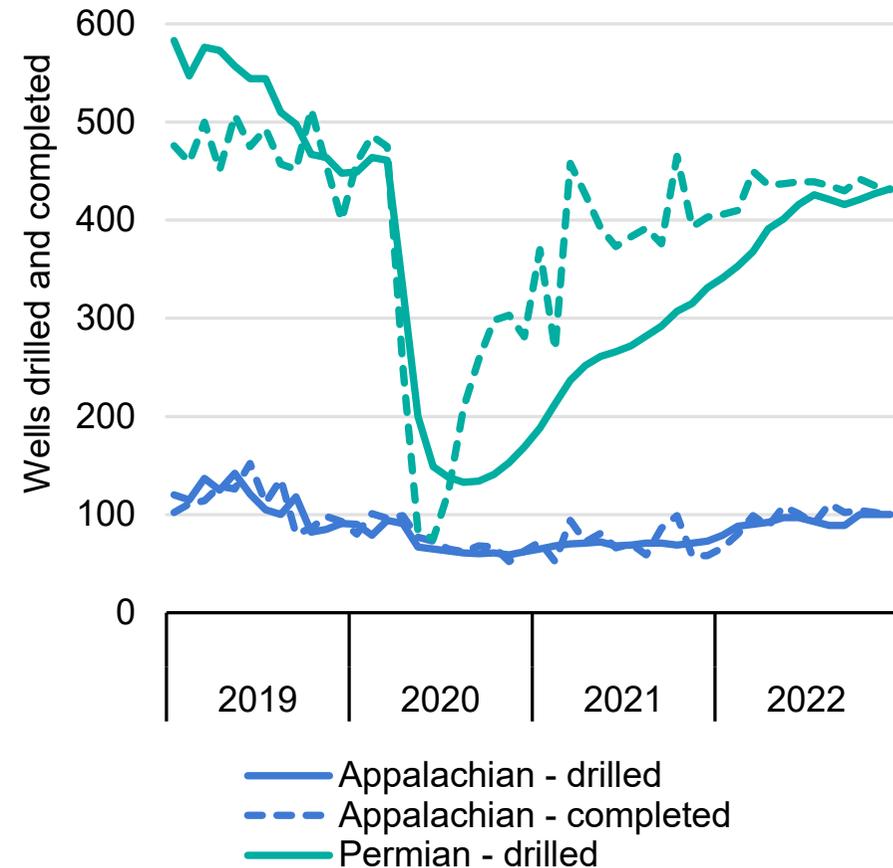
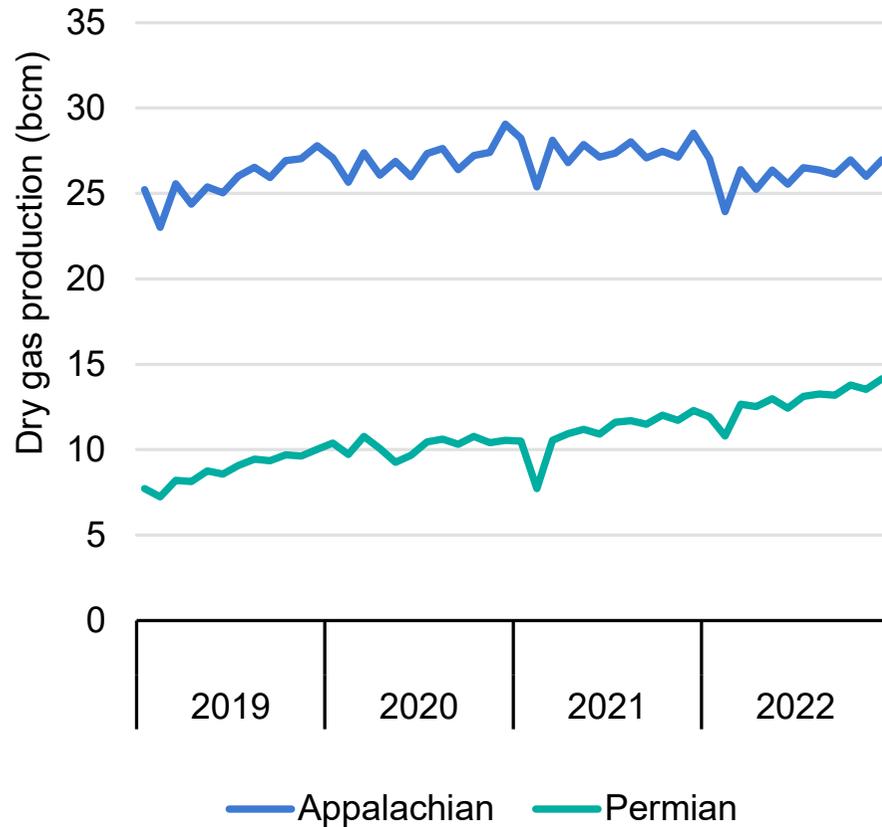


IEA. CC BY 4.0.

Sources: IEA analysis based on EIA (2023), [Natural Gas Data](#); [Natural Gas Weekly Update](#).

Production slightly declined in the Appalachian Basin in 2022 despite higher drilling and completion, while Permian drilling grew much faster than completion

Dry gas production and well drilling and completion activity, Appalachian and Permian basins, 2019-2022

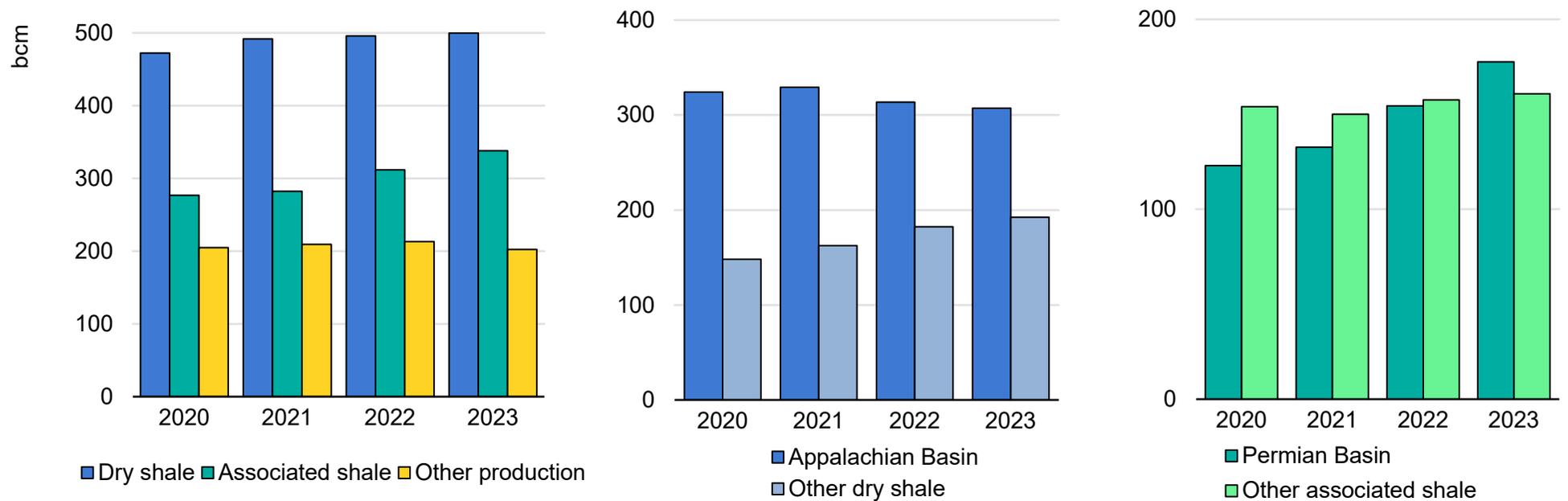


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Sources: IEA analysis based on EIA (2023), [Natural Gas Data](#); [Natural Gas Weekly Update](#); [Drilling Productivity Report](#).

US natural gas production growth is expected to slow in 2023

Dry gas production by main source, United States, 2020-2022



IEA. CC BY 4.0.

Sources: IEA analysis based on EIA (2023), [Natural Gas Data](#); [Natural Gas Weekly Update](#).

Russian piped gas supplies to Europe fell in 2022 to their lowest level since the mid-1980s

Russia's steep gas supply cuts to the European Union put unprecedented pressure on both European and global gas markets. Flexible LNG played a key role in partially offsetting the shortfall in Russian gas deliveries and maintaining gas supply security in Europe.

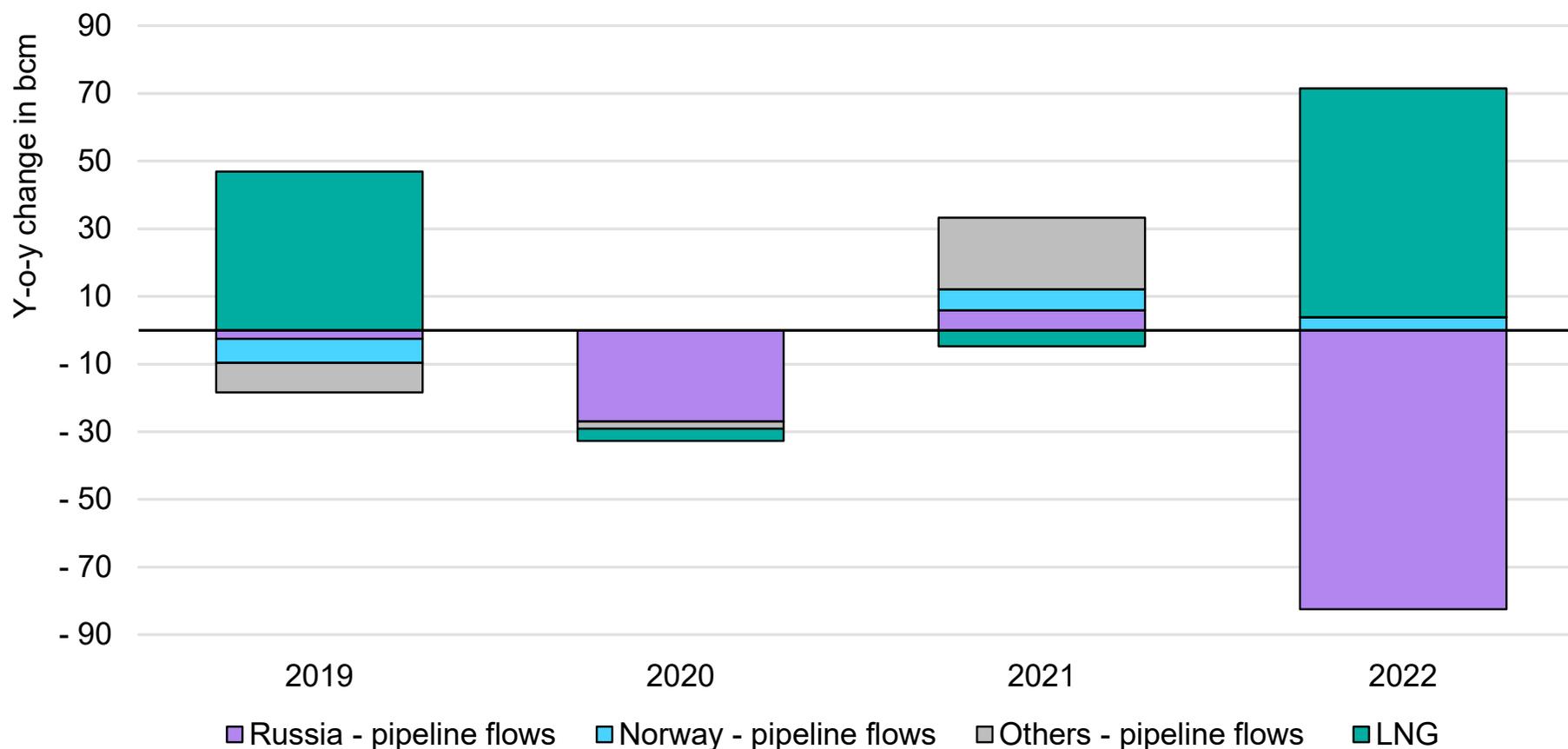
Russia's piped gas exports to OECD Europe fell by an estimated 50% (83 bcm) y-o-y in 2022, to their lowest level since the mid-1980s. While deliveries to Türkiye declined by 18% y-o-y, gas supplies to the European Union more than halved, translating into a drop of 78 bcm compared with 2021. Gazprom unilaterally cut gas supplies to several EU member states during Q2, following their refusal to adhere to a new payment system imposed by Russia. Russia introduced a range of sanctions on European companies in May, following which Gazprom announced that it would cease to use the Yamal–Europe pipeline. Gazprom gradually reduced gas flows via Nord Stream from mid-June and by the end of August had halted gas supplies completely via the pipeline. Hence, only three pipeline systems – the Ukraine transit route, Blue Stream and TurkStream – remained operational from September. Nord Stream and Nord Stream 2 suffered an act of sabotage at the end of September, with preliminary investigation finding traces of explosives. Russian piped gas supplies to OECD Europe fell by an estimated 70% (25 bcm) y-o-y in Q4 2022.

The steep drop in Russian piped gas supplies and stagnating non-Norwegian domestic production were compensated by higher pipeline deliveries from alternative sources and record volumes of LNG inflow. Pipeline flows from Norway rose by 3% (or 4 bcm) in 2022, with deliveries increasingly rerouted towards the European Union (up by 9%) at the expense of the United Kingdom (down by 14%). Gas supplies from Azerbaijan via the Trans Adriatic pipeline surged by 40% (or 3 bcm) y-o-y in 2022, while North African gas flows fell by 10% (or 4 bcm) due to the non-availability of the Maghreb–Europe pipeline and lower Libyan flows. LNG imports surged by 60% to close to 170 bcm – their highest level on record. LNG supplies from the United States to the European Union totalled at 25 bcm in the second half of 2022, standing well above Russia's piped exports.

The profile of Russian piped gas supplies remains a major uncertainty. Assuming that flows to the European Union continue at their current level, Russian piped gas deliveries to OECD Europe would drop by almost 40% (or 30 bcm) in 2023 compared with 2022. As highlighted in the IEA report [How to Avoid Gas Shortages in the European Union in 2023](#), Russian piped gas supplies to the European Union could cease completely, which would put further pressure on markets. LNG imports are expected to increase by close to 7%, although a stronger recovery in China's LNG imports would limit this growth to just 3%.

The steep drop in Russian piped gas supplies was partially offset by a record LNG inflow

Y-o-y change in European natural gas imports and deliveries from Norway, 2019-2022



IEA. CC BY 4.0.

Sources: IEA analysis based on ENTSOG (2022), [Transparency Platform](#); Eurostat (2022), [Energy Statistics](#); Gas Transmission System Operator of Ukraine (2022), [Transparency Platform](#); [ICIS LNG Edge](#); JODI (2022), [Gas World Database](#).

Global LNG trade growth reached 5.4% in 2022, with a massive shift in flows following Europe's switch from Russian pipeline gas to LNG

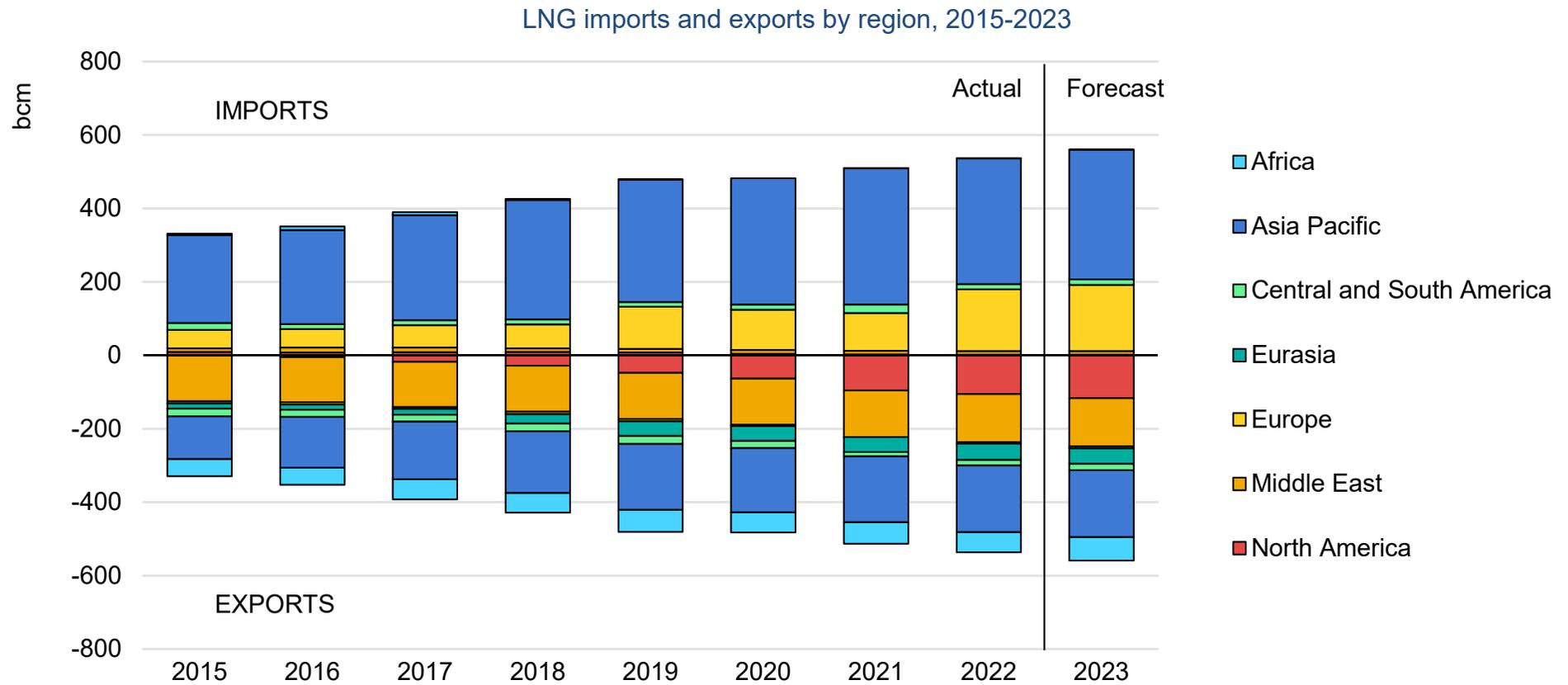
In 2022 global LNG trade expanded by 5.4%, a slightly lower growth rate than in 2021. **LNG import** growth in 2022 was led by Europe with a sharp 63% increase, compensating for a significant drop in pipeline gas imports from Russia. Meanwhile, demand in the Asia Pacific region was lower than expected and registered an 8% decline. China's imports were down by 21% (the largest annual decline in both absolute and percentage terms since the start of LNG imports in 2006), due to slow economic growth and Covid-related disruptions. Japan was once again the world's largest LNG importer, despite a modest 3% drop in LNG inflows in 2022. Korea imported the same amount of LNG in 2022 as in 2021. Conversely, price-sensitive South Asian importers saw sharp declines: India and Bangladesh both saw LNG imports decrease by 17%, while Pakistan was down by 18%, as high and volatile spot LNG prices suppressed demand. Despite the high price environment, Malaysia (up 45%), Thailand (up 28%), Singapore (up 22%), Indonesia (up 6%) and Chinese Taipei (up 4%) saw growing LNG imports, fuelled by strong power demand and economic activity – and in some cases also by declining domestic and pipeline gas supply. LNG imports in Central and South America dropped significantly (down 38%), thanks to the recovery of hydroelectric reservoir levels after the historic drought of 2021. LNG imports into Brazil dropped by 72% compared with 2021.

On the supply side, Qatar and Australia were the leading exporters in 2022, followed very closely by the United States. Exports from Qatar grew by 3%, while deliveries from Australia remained broadly stable at elevated levels, despite some upstream production constraints. North America's LNG exports increased by 11% in 2022 thanks to new liquefaction capacity additions (including the start-up of Calcasieu Pass LNG and the sixth train at Sabine Pass LNG) and despite the prolonged outage at the Freeport LNG terminal in Texas since June. LNG exports from Russia grew by 10% in 2022 and about 43% of Russia LNG output landed in the European Union (vs 35% in 2021), a sharp contrast to the declining trend in Russia–EU pipeline flows. Norway's Hammerfest LNG resumed production in June 2022 after extensive repairs following a fire in September 2020. In 2022 Norway's LNG exports were back to 2020 levels. Africa was the only exporting region where production decreased in 2022 (down 6%). The biggest export declines occurred in Nigeria (down 15%), Algeria (down 13%) and Angola (down 9%). LNG exports from Egypt continued to increase (up 10%), albeit at a much slower pace than last year when the previously idled Damietta LNG terminal was brought back into service. Trinidad and Tobago recovered from last year, its LNG exports increasing by 21% in 2022 thanks in part to the start-up of new upstream projects, including Colibri and Cassia C.

In Q4 2022 the rate of growth in global LNG trade accelerated to 5.6% y-o-y, a slight increase from a rate of 5.3% in the first three quarters of 2022. Europe's share of global LNG demand increased to 36% in Q4 2022, from 24% in Q4 2021. Meanwhile, the Asia Pacific region's share of LNG demand dropped to 62% in Q4 2022, from 72% in Q4 2021. European LNG imports increased by 52% in Q4 y-o-y, driven by the sharp reduction in Russian pipeline flows and higher storage injections stretching well into the fourth quarter. On the supply side, higher volumes of LNG trade were enabled by production increases in the United States, Qatar and Norway in particular.

In 2023 the volume of global LNG trade is set to increase by 4.3%. The expansion of LNG demand is fuelled by a continuing rise in European imports to an all-time high of 180 bcm (thanks in part to new import infrastructure) and by a modest recovery in Asia following the region's demand decline in 2022. LNG export growth continues at around 4.3% thanks to the anticipated return of the 20 bcm Freeport terminal to full production in Q1 2023, despite a marked slowdown in new liquefaction capacity additions in 2023.

Europe drove LNG import growth and North America led LNG export growth in 2022, a pattern expected to continue in 2023



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Source: IEA analysis based on ICIS (2022), [ICIS LNG Edge](#).

The big unknown: LNG demand in China in 2023

China's appetite for imported LNG ranks among the greatest uncertainties for 2023, not just for the global LNG market, but also for gas supply availability in Europe in the face of severely reduced pipeline gas flows to the continent from Russia. In 2022 net LNG imports into China dropped by an unprecedented 21% (22 bcm) compared with a 17% (16 bcm) increase in the previous year. This reduction played a crucial role in enabling a 63% (65 bcm) increase in LNG inflows into Europe to compensate for the lost Russian volumes. However, the 2022 collapse of Chinese LNG demand was precipitated by a unique set of factors – namely high spot LNG prices, slowing economic growth, and lockdowns under China's strict zero-Covid policy – that are unlikely to be repeated in precisely the same combination in 2023.

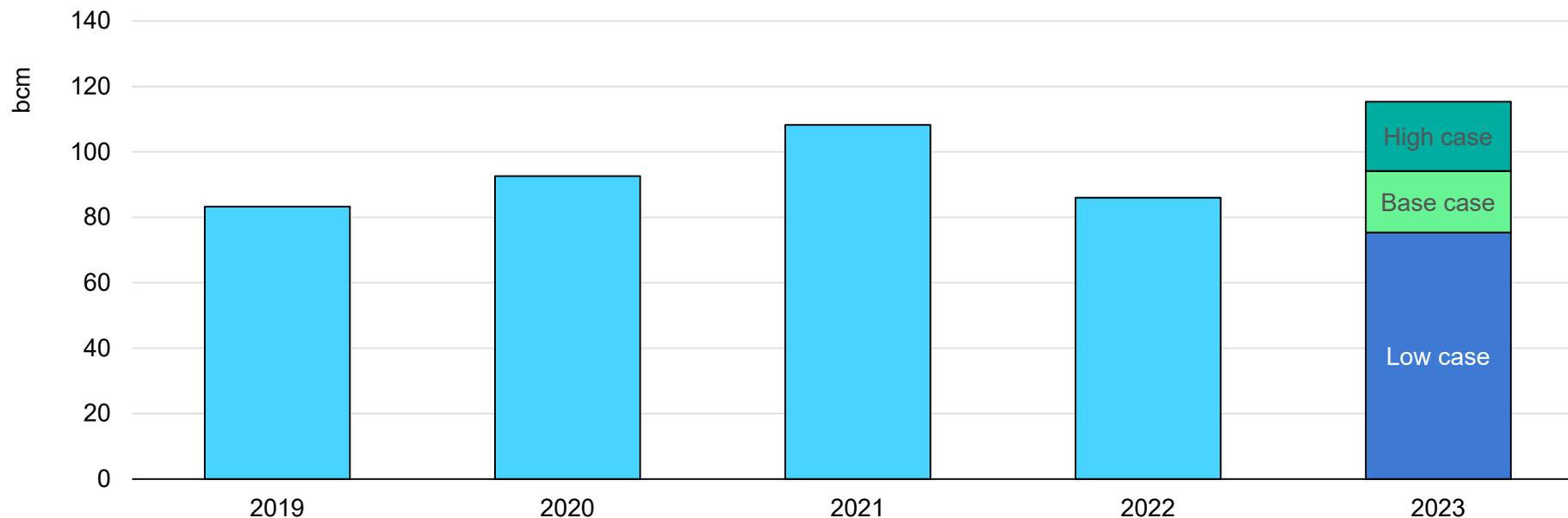
Our analysis indicates that a set of only moderately bearish assumptions on China's total gas consumption, domestic production and pipeline gas imports could depress the country's LNG demand by another 12% (10 bcm) in 2023, whereas a confluence of moderately bullish conditions could boost China's LNG intake by 35% (30 bcm) to well above the previous peak in 2021. The total uncertainty range is about 40 bcm, with China's 2023 net imports reaching 75 bcm at the low end and 115 bcm at the high end. This range is greater than the uncertainty associated with the potential loss of all remaining pipeline gas flows into Europe from Russia,

which have averaged about 28 bcm on an annualised basis since deliveries via the Nord Stream 1 pipeline were cut off indefinitely at the end of August 2022.

Our updated forecast anticipates China's LNG demand to reach 94 bcm in 2023. This would represent a 10% (8 bcm) increase on 2022, but falls closer to the low end of the uncertainty range. A disruptive "exit wave" of infections following China's recent break with its previous zero-Covid policy (signs of which were already evident in January 2023) presents substantial further downside risk to this forecast. Conversely, China's growing portfolio of LNG contracts means that the country's LNG demand in 2023 could be more resilient and less exposed to spot market pricing and volatility than it was prior to 2022. With about 13 bcm of new LNG contracts starting delivery in 2023, China's contracted LNG volume is on course to reach nearly 110 bcm this year, substantially higher than projected LNG demand in all but the most optimistic scenarios (and slightly higher than China's total LNG imports at their 2021 peak of 108 bcm). This means that in 2023 China could ramp up its LNG imports back to 2021 levels without the need to increase spot LNG purchases. At just under USD 15/MBtu, China's contracted LNG supplies were almost 30% cheaper than spot LNG imports during 2022, according to price data from S&P Global Commodity Insights.

China’s demand for LNG in 2023 presents 40 bcm of demand uncertainty for the global LNG market

LNG demand, China, 2019-2023



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Notes: Assumptions for 2023:

Low case: total consumption growth at 3.2% (lowest observed percentage growth in 2000-2021); domestic production growth at 15 bcm (average volume growth in 2019-2021); pipeline gas import growth at 11% (7 bcm) with Russia ramping up to 22 bcm, Central Asia flat at 2022 level and Myanmar delivering at 4.5 bcm (close to the 2019 peak rate).

Base case: total consumption growth at 6.5% per our updated Q1 2023 forecast; domestic production growth at 10 bcm (average volume growth in 2015-2020); pipeline gas import growth at 8% (6 bcm) with Russia ramping up to 22 bcm, Central Asia at close to the 2019 level (45 bcm) and Myanmar delivering at close to the 2020-2021 average rate (4 bcm).

High case: total consumption growth at 9.4% (average percentage growth in 2020-2021); domestic production growth at less than 5 bcm (based on a linear trajectory between 2022 and 2025 to reach the National Energy Administration’s March 2022 production target of 230 bcm by 2025); pipeline gas imports remain flat at 2022 levels (66 bcm), Russia ramps up to 22 bcm, Central Asia decreases to 40 bcm with Turkmenistan delivering at 2021 levels (33 bcm), Kazakhstan remaining flat (7 bcm) and Uzbekistan dropping to zero due to its inability to fulfil any export commitments; Myanmar delivers at close to the 2020-2021 average rate (4 bcm).

Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Easing market fundamentals put downward pressure on spot prices in Q4 2022

Russia's steep supply cuts to the European Union drove European hub prices, and indirectly Asian spot LNG, to all-time highs in 2022. In the United States, Henry Hub prices rose to their highest level since 2008 amid soaring gas demand for power generation. Easing supply–demand fundamentals provided downward pressure on spot prices across all key markets in Q4.

In Europe, TTF spot prices averaged a record high of USD 38/MBtu in 2022 – almost eight times their five-year average during 2016-2020. Gas prices rose to their highest level in Q3, as the steep decline in Russian piped gas coincided with higher gas burn in the power sector and strong storage injections. Month-ahead prices on the TTF spiked to an all-time high of EUR 340/MWh (USD 99/MBtu) at the end of August. However, spot prices on the TTF more than halved in Q4 compared with their Q3 levels to an average of USD 29/MBtu, despite Russia's continued gas supply cuts.

Unseasonably mild temperatures, above-average storage levels and record high LNG inflow weighed on European hub prices. Month-ahead TTF prices had an average premium of almost USD 8/MBtu above spot prices, reflecting the greater sensitivity of the spot market to short-term market forces, such as mild spells.

Asian spot LNG prices averaged USD 34/MBtu in 2022, their highest level on record and more than five times their five-year average during 2016-2020. The increasingly fierce competition with

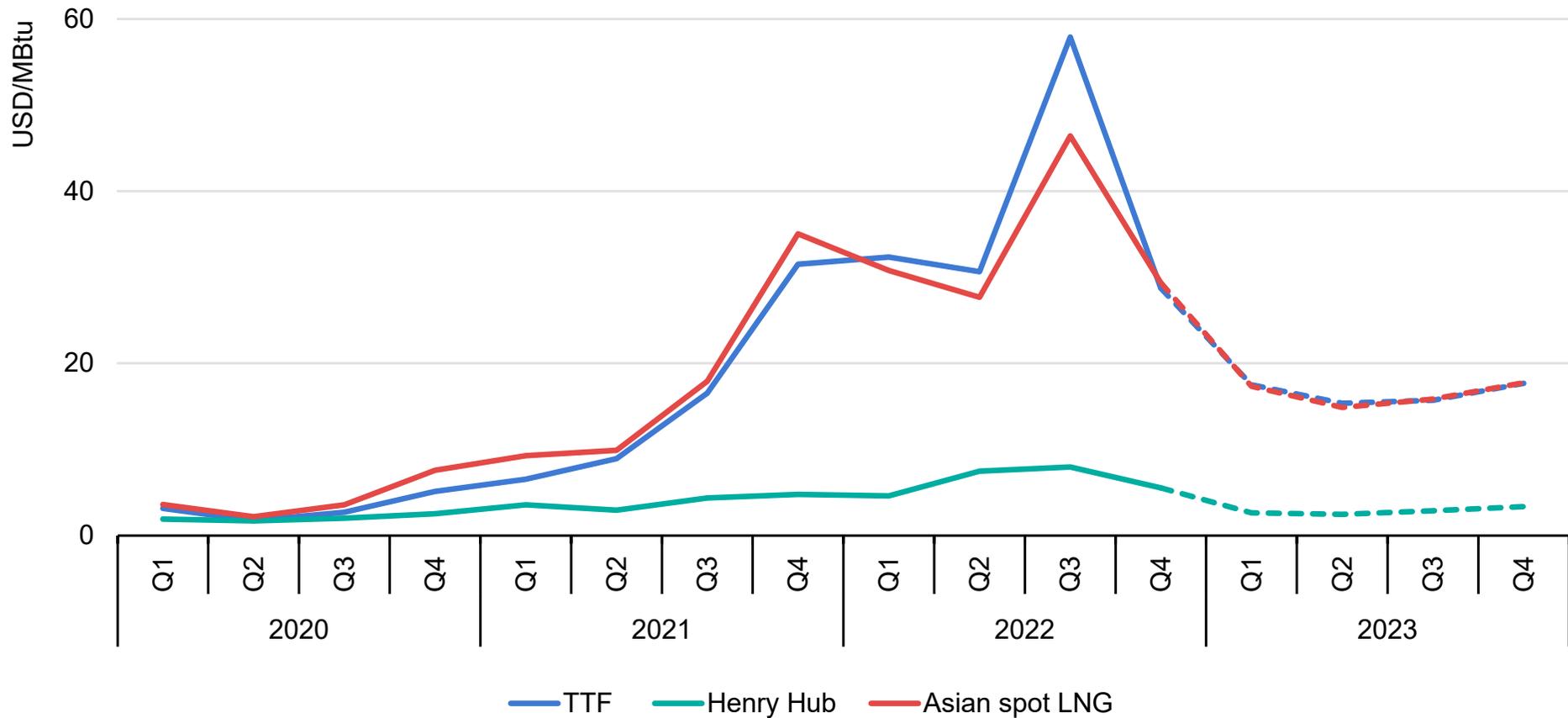
Europe for LNG cargoes, together with lower LNG supply from Australia and the United States, provided strong upward pressure on Asian LNG spot prices during the year. However, they fell by 36% in Q4 compared to the previous quarter amid lower European hub prices. Asian spot prices continued to display a discount of USD 7/MBtu compared to TTF month-ahead prices in Q4, which sustained high inflow of spot LNG into the European market.

In the United States, Henry Hub prices averaged USD 6/MBtu in 2022, their highest level since 2008. Higher gas demand for power generation (supported by a sharp increase in coal prices) coincided with strong y-o-y growth in LNG exports and a relatively weak supply response from US producers. Easing supply–demand fundamentals weighed on spot Henry Hub prices in Q4, which fell by 30% compared with Q3 to an average of USD 5.5/MBtu.

Gas prices moderated significantly in January 2023 across all key gas markets, although they remained well above historic averages in Asia and Europe. Forward curves as of the end of February 2023 indicate that TTF is set to average USD 17/MBtu, with Asian spot LNG averaging just below USD 17/MBtu and Henry Hub averaging USD 2.8 /MBtu in 2023. The price spread between TTF and Asian spot LNG is expected to tighten significantly in 2023.

The price spread between TTF and Asian spot LNG is expected to tighten in 2023

Main spot and forward natural gas prices, 2020-2023



IEA. CC BY 4.0.

Sources: IEA analysis based on CME (2022), [Henry Hub Natural Gas Futures Quotes](#), [Dutch TTF Natural Gas Month Futures Settlements](#); CME Group (2022), [LNG Japan/Korea Marker \(Platts\) Futures Settlements](#); EIA (2022), [Henry Hub Natural Gas Spot Price](#); ICIS (2021), [ICIS LNG Edge](#); Powernext (2022), [Spot Market Data](#).

Storage withdrawals displayed a varied pattern across key gas regions in Q4 2022

Natural gas storage plays a critical role in ensuring the security of gas supply during the heating season. In the European Union withdrawals fell significantly below their five-year average in Q4 amid unseasonably mild weather. In contrast, adverse weather conditions and strong gas demand in the United States increased reliance on storage.

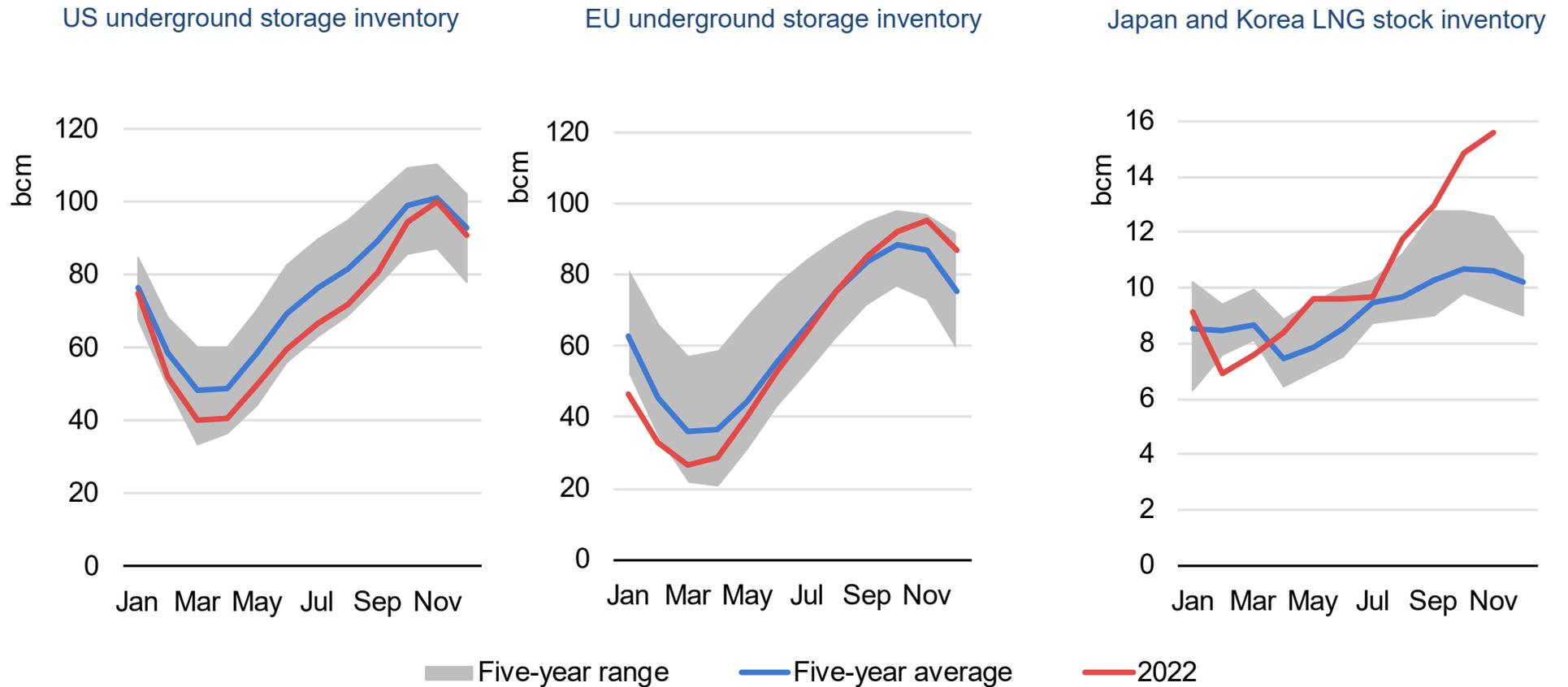
In the European Union the strong inflow of LNG combined with lower natural gas consumption enabled record storage injections in 2022. Despite the steep decline in Russian piped gas, storage injections stood 25% (14 bcm) above their five-year average and totalled over 70 bcm during the April to mid-November period. Unseasonably mild weather in October and the first half of November effectively delayed the start of the European heating season by one month, allowing gas injections totalling 4 bcm between mid-October and mid-November. This is a period when storage sites typically turn to withdrawals. Inventory levels had reached 95% of their working storage capacity by mid-November, standing 9% (or 8 bcm) above their five-year average. Low gas demand and record LNG inflow weighed on gas storage withdrawals, which stood 70% below their five-year average in Q4 2022 and totalled a record low of 5 bcm. While the call on gas storage declined on average in Q4, the cold spell in early December highlighted the importance of storage for gas supply security, with withdrawals meeting over 40% of gas demand on peak days. EU

storage sites closed 2022 with inventory levels standing 20% above their five-year average. Withdrawals remained below average in January 2023, keeping storage sites 72% full by 1 February, well above the intermediate EU target of 45%. EU storage sites were 60% full as end of February 2022. In Ukraine storage withdrawals stood at 1.5 bcm in Q4, leaving inventory levels below 18% of their working storage capacity by mid-February 2023. Rebuilding inventories to adequate levels in 2023 will be key to ensuring gas supply security in Ukraine during the next heating season and would require a ramp-up of imports from the European Union.

In the United States storage sites were 80% full at the beginning of November, well aligned with their five-year average. Storage withdrawals stood 15% (3 bcm) above their five-year average in Q4, as colder temperatures and higher gas burn in the power sector increased the call on gas storage. Net storage withdrawals met over 10% of total US domestic gas consumption during November and December. Storage sites were 68% full at the end of 2022 and 51% by mid-February 2023, standing 15% (or 8 bcm) above their five-year average.

In Japan and Korea LNG closing stocks stood 45% above their five-year average in November 2022. The LNG stocks of Japan's largest power generation companies stood at 2.6 Mt (3.6 bcm) in mid-February, 30% above their five-year average.

EU storage sites closed 2022 with inventory levels well above their five-year average



IEA. CC BY 4.0.

Sources: IEA analysis based on EIA (2022), [Weekly Working Gas in Underground Storage](#); GIE (2022), [AGSI+ Database](#); IEA (2022), [Monthly Gas Data Service](#).

Low-emission gases

The gas supply shock of 2022 put the spotlight on low-emission gases

The global gas and energy crisis triggered by Russia's invasion of Ukraine once again reminded the world of the importance of energy supply security, and in doing so highlighted the need to accelerate clean energy transitions while reducing vulnerabilities arising from fossil fuel import dependency. Low-emission gases³ are at the intersection of energy supply security and decarbonisation efforts: besides contributing to lower-emission pathways, domestically produced low-emission gases enhance market resilience and can significantly reduce reliance on fossil fuel imports.

In the European Union the European Commission published the REPowerEU Plan in May 2022, setting out a vision to further accelerate the green transition and cut the bloc's dependence on Russian fossil fuel imports. REPowerEU sets ambitious trajectories for low-emission gases, including:

- Biomethane production ramping up to 35 bcm/yr by 2030 – a more than tenfold increase from today's levels.
- Low-emission hydrogen supply increasing to 20 Mt by 2030, of which 10 Mt is to be imported from diverse sources. Depending on the

end-use sector, the rapid scale-up of low-emission hydrogen could replace 34-68 bcm/yr of natural gas by 2030.

In the United States the Inflation Reduction Act was signed into law in August 2022, giving a significant boost to clean energy technologies through the provision of USD 370 billion of funding for energy security and climate change investments. The act is set to significantly boost the deployment of low-emission gases through a number of measures, including:

- Tax credits of up to 30% for biogas facilities built by the beginning of 2025.
- Production tax credits for clean hydrogen plants in 2023, which can receive credits of USD 0.026 per kWh and up to USD 3 per kg of hydrogen for the first ten years of operation.

In Japan the Green Transformation (GX) programme is set to provide a major funding boost for technologies that produce low-emission hydrogen, synthetic methane and ammonia. The programme dedicates JPY 7 trillion (approximately USD 52 billion) in subsidies over the next 10 years to establish a hydrogen and ammonia supply network.

³ Low-emission gases include biomethane, low-emission hydrogen, synthetic methane and natural gas subject to carbon capture, utilisation and storage (CCUS)-based technologies.

European countries set more ambitious hydrogen targets for the medium term

Several European countries unveiled their hydrogen strategies and roadmaps in 2022. Others revised their hydrogen strategies, setting more ambitious deployment targets for the medium term.

Austria published its National Hydrogen Strategy in June 2022. The strategy targets the installation of 1 GW of electrolyser capacity for the production of renewable hydrogen by 2030. For demand creation, the strategy focuses on hard-to-abate sectors, including energy-intensive industries.

In Belgium the Federal Hydrogen Vision and Strategy was approved by the Council of Ministers in October 2021. An updated version was published in October 2022. The strategy focuses particularly on the importance of renewable hydrogen and its potential to decarbonise industry and transport. According to the updated version, total domestic demand for both hydrogen molecules and hydrogen derivatives is seen to increase to 125-200 TWh/yr by 2050.

Denmark adopted its Power-to-X Strategy in March 2022 to accelerate the conversion of electricity into green hydrogen and other e-fuels over ten years. The country aims to build 4-6 GW of electrolysis capacity by 2030. The strategy is intended to support

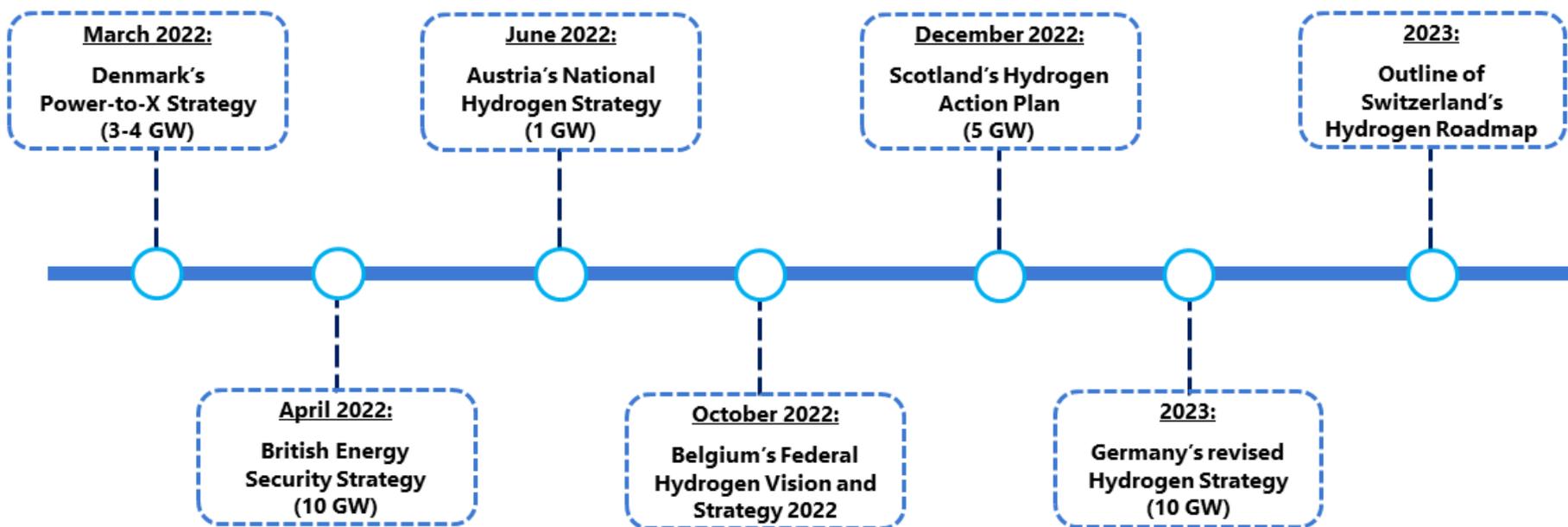
the use of green hydrogen particularly in hard-to-abate sectors like shipping and aviation, as well as heavy road transport and industry.

Germany published its National Hydrogen Strategy in June 2020, with a target for 5 GW of electrolyser capacity by 2030. The Federal Government is currently working on revising the hydrogen strategy in order to ensure that the targets from the coalition agreement (e.g. increasing the electrolyser capacity to 10 GW by 2030) are met. Publication is planned for 2023.

The United Kingdom published its Hydrogen Strategy in 2021, setting an ambition for 5 GW of low-carbon hydrogen production capacity by 2030. The British Energy Security Strategy, published in April 2022, doubled the production capacity ambition to up to 10 GW by 2030, with at least half of this coming from electrolytic hydrogen. Scotland published its Hydrogen Action Plan in December 2022. The plan has a target of 5 GW of renewable and low-carbon hydrogen by 2030 and 25 GW by 2045.

The Swiss Hydrogen Roadmap is currently in preparation with a first outline due to be published in 2023. A hydrogen paper was published in September 2022. It presents nine statements on the goals, role and areas of application of hydrogen in Switzerland.

Hydrogen strategies, roadmaps and papers published in Europe since 2022



IEA. CC BY 4.0.

Source: IEA analysis based on various policy documents.

Biomethane production grew by a record amount in 2022

2022 marked another record year for biomethane production growth. Global biomethane supply increased by an estimated 16% (or 1 bcm) in 2022 to close to 7 bcm. This was primarily driven by the European Union and the United States, together accounting for approximately 90% of incremental biomethane supply.

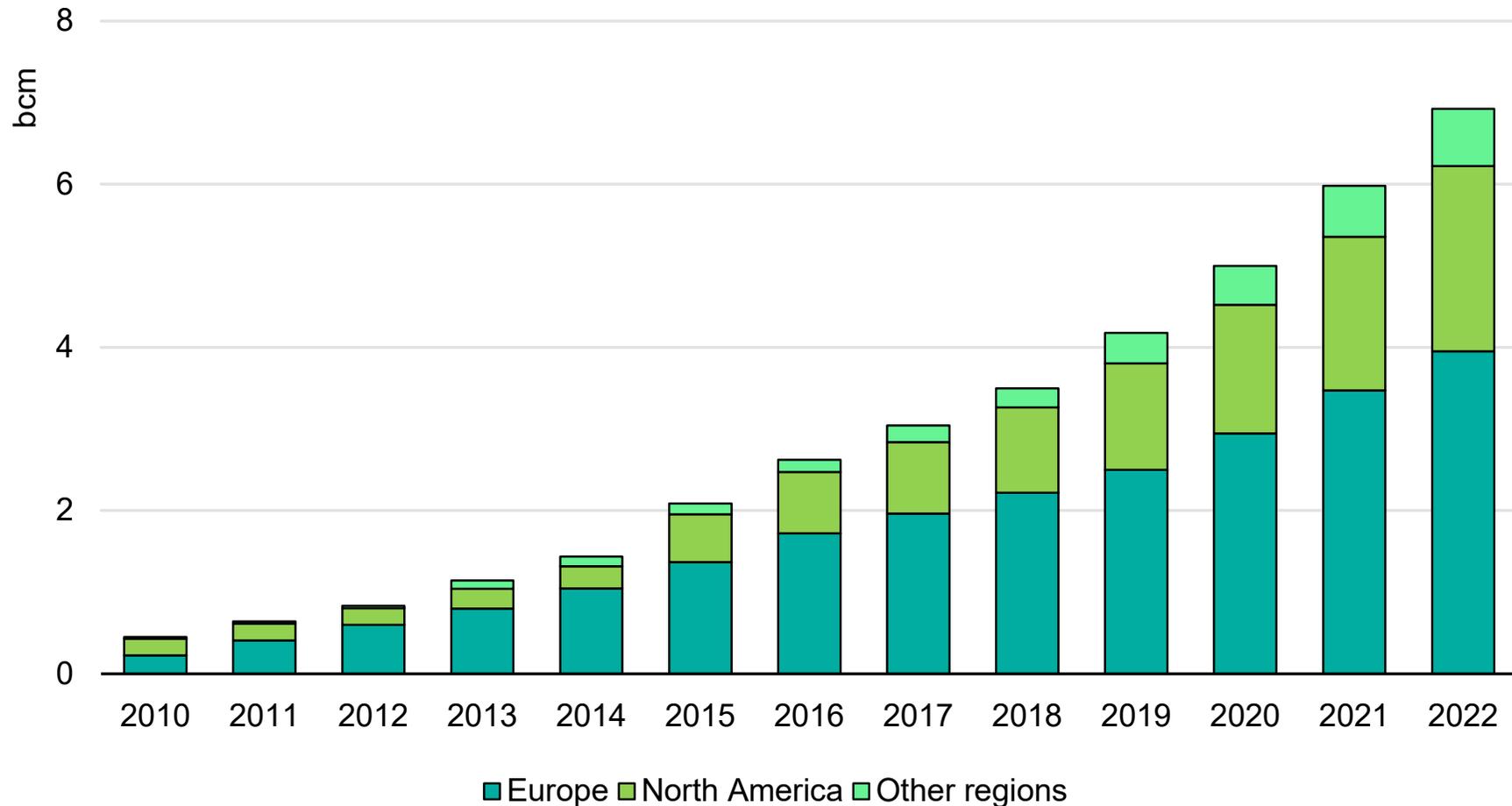
The United States remains by far the largest biomethane-producing country in the world, a position it has held since 2019. The country's biomethane output grew by an impressive 20% (close to 0.4 bcm) to reach 2 bcm in 2022, accounting for almost 30% of global biomethane output. It currently has over 250 operational biomethane facilities, with around 220 additional plants under construction or planned. Municipal solid waste remains the single largest source of feedstock, underpinning approximately 70% of total US biomethane production. Agricultural waste accounts for almost 20% of biomethane feedstock supply, while food waste and waste water account for the remaining 10%. Supply growth in 2022 was largely driven by biomethane facilities relying on agricultural waste as a feedstock. These plants alone accounted for over 55% of incremental biomethane supply in 2022, followed by facilities using municipal solid waste. It is estimated that around 90% of biomethane production facilities have grid injection capability, with the remaining 10% dedicated to on-site use. As for end use, approximately 90% of biomethane serves as a transport fuel, with

the remaining 10% primarily used for power generation. The Renewable Natural Gas Incentive Act of 2022 was introduced in Congress in December 2022. The bill would create a ten-year USD 1 per gallon tax credit for sellers of renewable natural gas used for transport.

In the European Union biomethane production increased by an estimated 15% (0.5 bcm) to close to 4 bcm in 2022. This growth was primarily driven by Denmark and France, together accounting for almost two-thirds of incremental biomethane supply in Europe. In France biomethane output grew by an estimated 65% compared with 2021 to reach 0.65 bcm. This puts France as the second largest biomethane producer in Europe, behind Germany and surpassing Denmark. The number of biomethane facilities in France surged from 365 at the end of 2021 to 442 plants as of mid-2022. Agricultural waste accounts for around 80% of the feedstock supply used for biomethane production. In Denmark biomethane output grew by 15% compared with 2021 to reach over 0.6 bcm. The share of biomethane in total domestic gas consumption rose from 20% in 2021 to over 30% in 2022 – the highest share of any European country. European natural gas spot prices had an average premium of USD 11-24/MBtu above the typical cost range of biomethane production in 2022, and hence contributing to a lower natural gas import bill.

Global biomethane production reached close to 7 bcm in 2022

Estimated biomethane production by region, 2010-2022

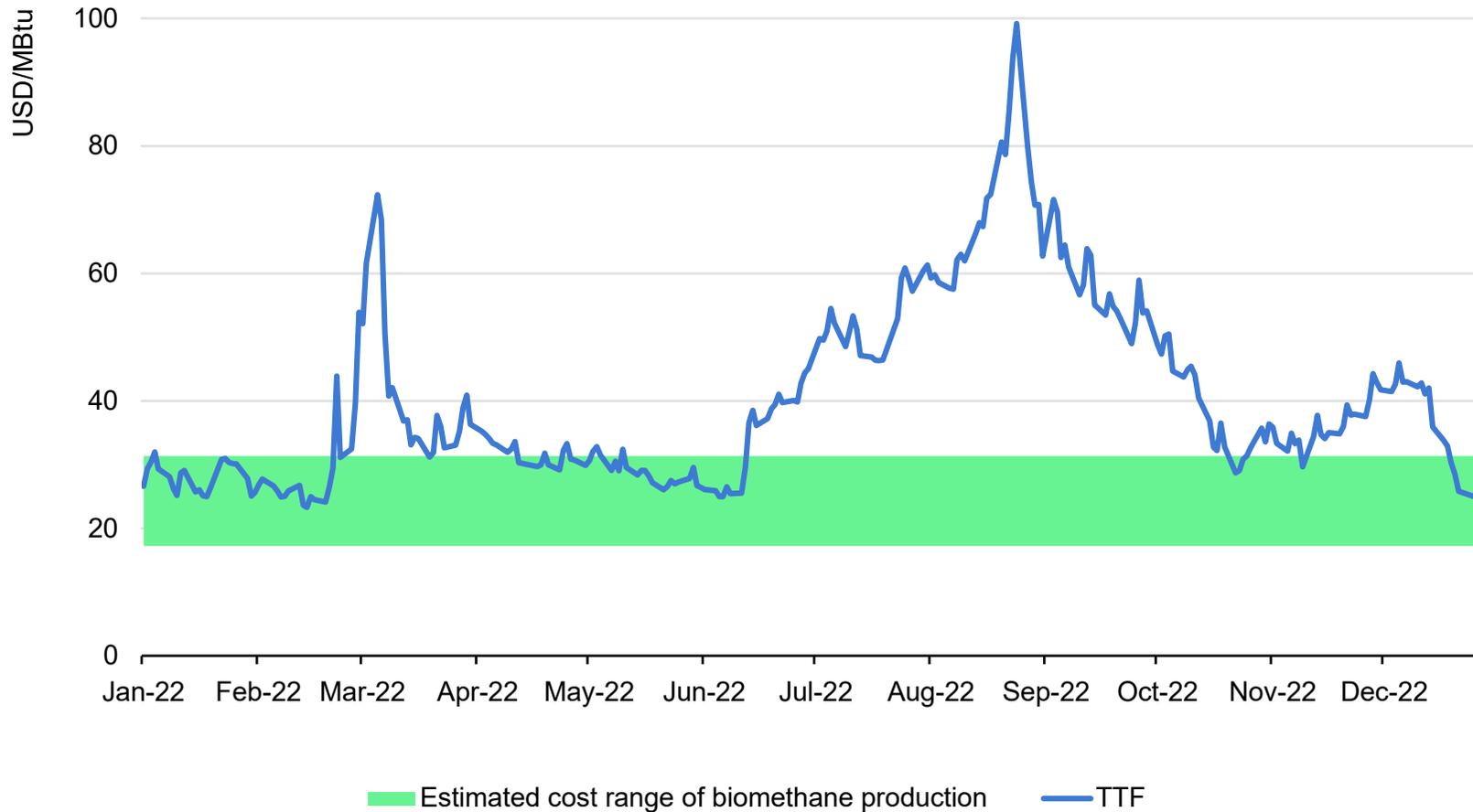


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Sources: IEA analysis based on CBS (2022) [Open Data](#); Cedigaz (2021), Global Biomethane Database; Energinet (2022), [Energi Data Service](#); GRDF (2022), [Production annuelle de biométhane par site d'injection](#); [RNG Coalition](#) (2022).

European hub prices averaged well above the production cost range of biomethane

Daily TTF month-ahead prices vs estimated cost range of biomethane production, January 2022-December 2022



IEA. CC BY 4.0.

Sources: IEA analysis based from TTF month-ahead prices sourced from ICE (2023), [Dutch TTF Natural Gas Futures](#).

Low-emission gases are making inroads into the corporate strategies of oil and gas majors

Low-emission gases are gaining traction among oil and gas majors, highlighted by several landmark acquisitions and investments during 2022. Several factors are underpinning this orientation of corporate strategies towards low-emission gases, in particular the opportunity to:

- Reduce their Scope 3 emissions amid tightening regulatory standards.
- Diversify their assets and fuel supply portfolio with a strategic view to becoming part of an increasingly decarbonised energy system.
- Build up skills and capabilities in relation to the production and marketing of low-emission gases.
- Benefit from interoperability with existing infrastructure and synergies with their existing retail and marketing activities.

This section provides a non-exhaustive overview of the major project developments and company acquisitions undertaken by oil and gas majors in 2022.

Biomethane

Compared to other low-emission gases, biomethane production is considered a more mature technology with significantly lower costs. Hence, acquiring biomethane-related assets can drive emission reductions in the short term. Significant deals in 2022 were as follows:

- In October 2022 **BP** announced the acquisition of **Archaea Energy**, a leading biomethane producer in the United States, for USD 4.1 billion. The deal was completed on 28 December. Archaea Energy operates 50 biomethane and landfill gas-to-energy facilities across the United States, producing around 13 MBtu of biomethane per year. BP's ambition, based on a significant development pipeline, is to produce close to 145 MBtu of biomethane by 2030.
- In November 2022 **Shell** announced the acquisition of **Nature Energy**, the Denmark-based European leader in biomethane production from organic waste, for nearly USD 2 billion. The deal was completed at the end of February 2023. Nature Energy has 14 operating plants that currently produce about 6.5 MBtu of biomethane per year. With a development pipeline of about 30 projects in Europe and North America, the objective is to reach 16 MBtu by 2030. This acquisition will scale up Shell's existing biogas business, which consists of one operational site and four under construction, all in the United States, plus trading and supply units, as part of Shell's strategy to build an integrated biomethane value chain at global scale.
- In January 2023 **Chevron** completed the acquisition of **Beyond6** and its network of 55 compressed natural gas (CNG) stations across the United States. As part of the transaction, Mercuria and Chevron have entered a long-term supply relationship to deliver biomethane to Chevron.

Specific peer-to-peer contracts, such as biomethane purchase agreements, are still nascent but could drive demand as regulatory support decreases. These long-term contracts, concluded between a biomethane producer and an offtaker, include all the terms of the agreement, such as the amount of biomethane to be supplied, the negotiated price, who bears what risk, the required accounting, and the penalties if the contract is not honoured. It partially removes the risk of market fluctuations, which encourages investment in debt-financed projects.

Low-emission hydrogen

Oil and gas majors are gradually increasing their exposure to hydrogen projects through the acquisition of and investment in production assets. Key acquisitions and project investments in 2022 include the following:

- **BP** agreed in June 2022 to acquire a 40.5% share and become the largest shareholder in the **Asian Renewable Energy Hub (AREH)** in Western Australia. The project is to be supported by 26 GW of renewables capacity, with a target to produce up to 1.6 Mt/yr of hydrogen and around 9 Mt/yr of green ammonia.
- **TotalEnergies** agreed in June 2022 to acquire a 25% interest in **Adani New Industries Limited (ANIL)**. ANIL has a target to produce 1 Mt/yr of low-emission hydrogen by 2030, underpinned by around 30 GW of new renewable power generation capacity.
- **Shell** took a final investment decision in July 2022 to build **Holland Hydrogen I**. The project is to be underpinned by a 200 MW capacity

electrolyser to produce up to 60 000 kilograms of renewable hydrogen per day (equivalent to 0.02 Mt/yr), making it Europe's largest renewable hydrogen plant once operational in 2025.

- **Shell Oman** acquired a 35% stake in **Green Energy Oman (GEO)** in January 2023 to join the consortium developing Oman's largest low-emission hydrogen project. The project is expected to be developed in multiple phases to produce approximately 1.8 Mt/yr of low-emission hydrogen at full capacity.

Synthetic methane and LNG

Synthetic methane (or e-methane) is produced by combining low-emission hydrogen and a carbon source. While it is perfectly interchangeable with natural gas, its production costs remain elevated (at above USD 50/MBtu) and would require the development of a separate carbon value chain and emission accounting system. Similarly to natural gas, synthetic methane can be liquefied into liquid synthetic gas (LSG) and shipped via LNG carriers. Japan's 6th Strategic Energy Plan has set a target for synthetic methane to comprise 1% of the city gas supply in existing networks by 2030, increasing to 90% by 2050.

Japanese companies are considering several projects to develop synthetic methane with the aim of importing it into Japan:

- **Marubeni** and **Osaka Gas** announced in July 2022 a project to study the production of synthetic methane in Peru and its delivery to Japan.

- **Tokyo Gas, Osaka Gas and Toho Gas** entered an agreement with **Mitsubishi** at the end of November 2022 to conduct a feasibility study of the production of synthetic methane at the Cameron LNG terminal in the United States. The companies' intention is to export 130 000 t/yr of synthetic methane by 2030.
- **Osaka Gas, Tallgrass Energy and Green Plains** agreed in December 2022 to conduct a joint feasibility study on synthetic methane production. The firms aim to produce up to 200 000 t/yr of synthetic methane by 2030 and export it to Japan from the Freeport LNG export terminal in the United States.

Annex

Summary table

World natural gas consumption and production by region and key country (bcm)

	Consumption					Production				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
Africa	164	161	169	163	167	252	241	262	254	266
Asia Pacific	829	834	891	876	903	630	626	651	659	666
<i>of which China</i>	307	325	367	364	388	174	189	205	218	228
Central and South America	156	142	153	149	148	167	150	148	151	153
Eurasia	608	584	634	610	602	921	866	961	873	825
<i>of which Russia</i>	482	460	501	475	467	738	692	762	672	620
Europe	590	576	609	522	505	249	230	222	229	226
Middle East	543	547	562	575	598	668	669	693	712	734
North America	1 104	1 079	1 091	1 147	1 117	1 174	1 154	1 189	1 240	1 258
<i>of which United States</i>	886	868	874	921	890	968	954	984	1021	1041
World	3 993	3 924	4 109	4 042	4 041	4 061	3 936	4 125	4 119	4 128

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other countries and territories.¹

Asia Pacific – Australia, Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Japan, Korea, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, the People's Republic of China,² the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other countries and territories.³

Central and South America – Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other countries and territories.⁴

Eurasia – Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

Europe – Albania, Austria, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,^{5,6} Czech Republic, Denmark, Estonia, Finland, the Former Yugoslav Republic of North Macedonia, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo,⁷ Latvia, Lithuania, Luxembourg, Malta, the Republic of Moldova, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, Ukraine and United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,^{5,6} Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain and Sweden.

Middle East – Bahrain, the Islamic Republic of Iran, Iraq, Israel,⁸ Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

North Africa – Algeria, Egypt, Libya, Morocco and Tunisia.

North America – Canada, Mexico and the United States.

¹ Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda.

² Including Hong Kong.

³ Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

⁴ Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, St. Lucia, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands.

⁵ Note by the Republic of Türkiye.

The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. The Republic of Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, The Republic of Türkiye shall preserve its position concerning the "Cyprus issue".

⁶ Note by all the European Union Member States of the OECD and the European Union. The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

⁷ The designation is without prejudice to positions on status, and is in line with the United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of Independence.

⁸ The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators (European Union)	ICIS	Independent Chemical Information Services
ANP	National Petroleum Agency (Brazil)	JKM	Japan Korea Marker
AUD	Australian dollar	JODI	Joint Oil Data Initiative
BMC	Colombian Mercantile Exchange (Colombia)	JOGMEC	Japan Organization for Metals and Energy Security (Japan)
CME	Chicago Mercantile Exchange (United States)	JPY	Japanese yen
CNE	National Energy Commission (Chile)	KEEI	Korea Energy Economics Institute (Korea)
CNG	compressed natural gas	LNG	liquefied natural gas
CQPGX	Chongqing Petroleum Exchange (the People's Republic of China)	MCM	Market Correction Mechanism (European Union)
DUC	drilled but uncompleted wells	METI	Ministry of Economy, Trade and Industry (Japan)
EIA	Energy Information Administration (United States)	MME	Ministry of Mines and Energy (Brazil)
EMA	Energy Market Authority (Singapore)	NBP	National Balancing Point (United Kingdom)
ENARGAS	National Gas Regulatory Entity (Argentina)	NDRC	National Development and Reform Commission (the People's Republic of China)
ENTSOG	European Network of Transmission System Operators for Gas	OECD	Organisation for Economic Co-operation and Development
EPIAS	Energy Markets Operations Inc. (the Republic of Türkiye)	ONS	National Electric System Operator (Brazil)
EPPO	Energy Policy and Planning Office (Thailand)	OSINERG	Energy Regulatory Commission (Peru)
EU	European Union	OTC	Over the counter
EUR	Euro	PPAC	Petroleum Planning and Analysis Cell (India)
FID	final investment decision	SBL	Strategic Buffer LNG (Japan)
GIE	Gas Infrastructure Europe	TAP	Trans Adriatic Pipeline
GTSOU	Gas Transmission System Operator of Ukraine (Ukraine)	THE	Trading Hub Europe (Germany)
GX	Green Transformation programme (Japan)	TTF	Title Transfer Facility (the Netherlands)
HH	Henry Hub	UK	United Kingdom
IEA	International Energy Agency	USD	United States dollar
ICE	InterContinentalExchange	y-o-y	year-on-year

Units of measure

bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcm	billion cubic metres
bcm/y	billion cubic metres per year
GJ	gigajoule
GW	gigawatt
kWh	kilowatt hour
MBtu	million British thermal units
Mt	million tonne
MWh	megawatt hour
TWh	terawatt hour

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