Gas Market Report, Q1-2024

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Abstract

Natural gas markets moved towards a gradual rebalancing in 2023, despite tighter supply fundamentals. Demand reductions in Europe and mature markets in Asia softened the impact of the gas supply shock of 2022. Prices came down significantly in 2023, although they remained well above their historical averages, both in Asia and Europe.

Natural gas markets are expected to see a return to strong growth in 2024, primarily driven by the industrial and power sectors in fast-growing economies in Asia and gas-rich countries in Africa and the Middle East. An expected return to average winter weather conditions, after an exceptionally mild 2023, is expected to support higher demand for space heating in the Northern Hemisphere. However, the continued expansion of renewables and improving nuclear availability are likely to temper requirements for gas-fired power generation in mature markets.

High inventory levels together with an improving supply outlook are providing gas markets with some reassurance for 2024. However, geopolitical tensions, rising shipping constraints, LNG project delays and adverse weather conditions could renew market tensions and fuel price volatility. Security of supply for natural gas remains a key aspect of energy policy making and the risks related to our outlook highlight the need to strengthen international co-operation, including in assessing and implementing flexibility options along gas and LNG value chains.

This edition of the quarterly *Gas Market Report* by the International Energy Agency (IEA) provides a thorough review of market developments in 2023 and a short-term outlook for 2024. It also includes a special spotlight on greenhouse gas emissions along gas supply chains that examines emissions reduction initiatives undertaken by the largest natural gas and LNG producers and consumers. As part of the IEA's Low-Emissions Gases Work Programme, the report includes a section on policy and market developments related to biomethane, low-emissions hydrogen and e-methane.

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Executive summary

Natural gas markets moved to rebalancing in 2023 and are expected to return to growth in 2024

Following the gas supply shock of 2022, **natural gas markets moved towards a gradual rebalancing** in 2023 due to timely policy action, market forces and favourable weather conditions. Gas prices decreased significantly compared with their 2022 highs but remain well above their historical averages in Asia and Europe. **Hub liquidity improved** across all key markets amid higher trading activity. Despite this gradual rebalancing, the market remained tight on the supply side, and prices continued to display high volatility. **Natural gas markets are expected to return to growth in 2024**, although the expansion of gas use will be capped in import markets by the limited increase in global LNG supply.

Natural gas prices declined steeply across all key markets in 2023

Asian spot LNG and European hub prices have more than halved since 2022 but remain more than double the averages between 2016-20. **Gas supplies remained tight** as the increase in global LNG production (+13 bcm) was not sufficient to offset the continued decline in Russian piped gas deliveries to Europe (-38 bcm). **LNG production growth fell short of previous expectations** due to a combination of project delays and feedgas supply issues. The **United States** accounted for 80% of additional LNG supply and became the world's largest LNG exporter.

The **softening of market conditions in 2023 was primarily driven by the demand side**. The rapid expansion of **renewables** and **improving nuclear availability** weighed on natural gas demand in Europe and mature markets in Asia, driving prices lower. **Mild winter weather** conditions together with **gas-saving measures** also reduced gas use in the residential and commercial sectors. As such, **global gas demand** grew by an estimated 0.5% in 2023, which was not enough to make up the losses of 2022 when demand dropped by 1.5%. Demand growth was primarily supported by China, North America and the gas-rich markets in Africa and the Middle East. **China regained its position as the world's largest LNG importer** with natural gas demand increasing by 7%. In contrast, **natural gas consumption in Europe fell by 7% to its lowest level since 1995**.

Security of supply concerns, affordability issues and emissions reduction efforts are setting the direction for gas-related policies

The global energy crisis triggered by Russia's invasion of Ukraine put **security of supply for natural gas** at the forefront of energy policymaking. Policy measures and new regulations enacted in 2022 reinforced gas supply security in key import markets and were complemented by new instruments in 2023. The **European Union** launched its **Joint Gas Purchasing mechanism** in April 2023. Four tendering rounds have been organised in 2023 and overall 45 bcm of gas demand was matched with supply via the AggregateEU platform (equating to almost 15% of EU gas demand). **Singapore** announced in October 2023 plans to **centralise natural gas procurement** for the country's power sector. **Japan**'s Ministry of Economy, Trade and Indusry launched the country's **Strategic Buffer LNG** ahead of the 2023/24 winter season. In **China**, the National Energy Administration released a draft version of the **Natural Gas Utilization Policy**, setting out the guiding principles for an "orderly growth in natural gas demand" in the coming years.

Recognising the importance of **international cooperation to achieve greenhouse gas reductions in gas supply chains**, the IEA carried out a **survey** on the initiatives, policies and regulations enacted by the largest producers and consumers of both natural gas and LNG. The survey found that key natural gas exporters and importers reinforced their commitment to reduce emissions along gas supply chains, although **further efforts are needed** to harmonise measurement, monitoring, reporting and verification mechanisms and incentivise the investments required to effectively reduce natural gas-related greenhouse gas emissions.

Low-emissions gases benefit from strong policy momentum

Low-emissions gases continued to benefit from a wide range of policy initiatives in 2023. The **European Union** launched a new financing mechanism, the Hydrogen Bank, and a political agreement was reached on the hydrogen and decarbonised gas markets package. The **United States** published its National Clean Hydrogen Strategy and Roadmap and announced USD 7 billion of federal support to launch seven Regional Clean Hydrogen Hubs. **Japan** published its Basic Hydrogen Strategy in June 2023, with the aim to scale-up domestic hydrogen demand to 3 Mt/yr by 2030. **India** published its National Green Hydrogen Mission and approved a first mandatory blending of compressed biogas into domestic gas supply starting in 2025.

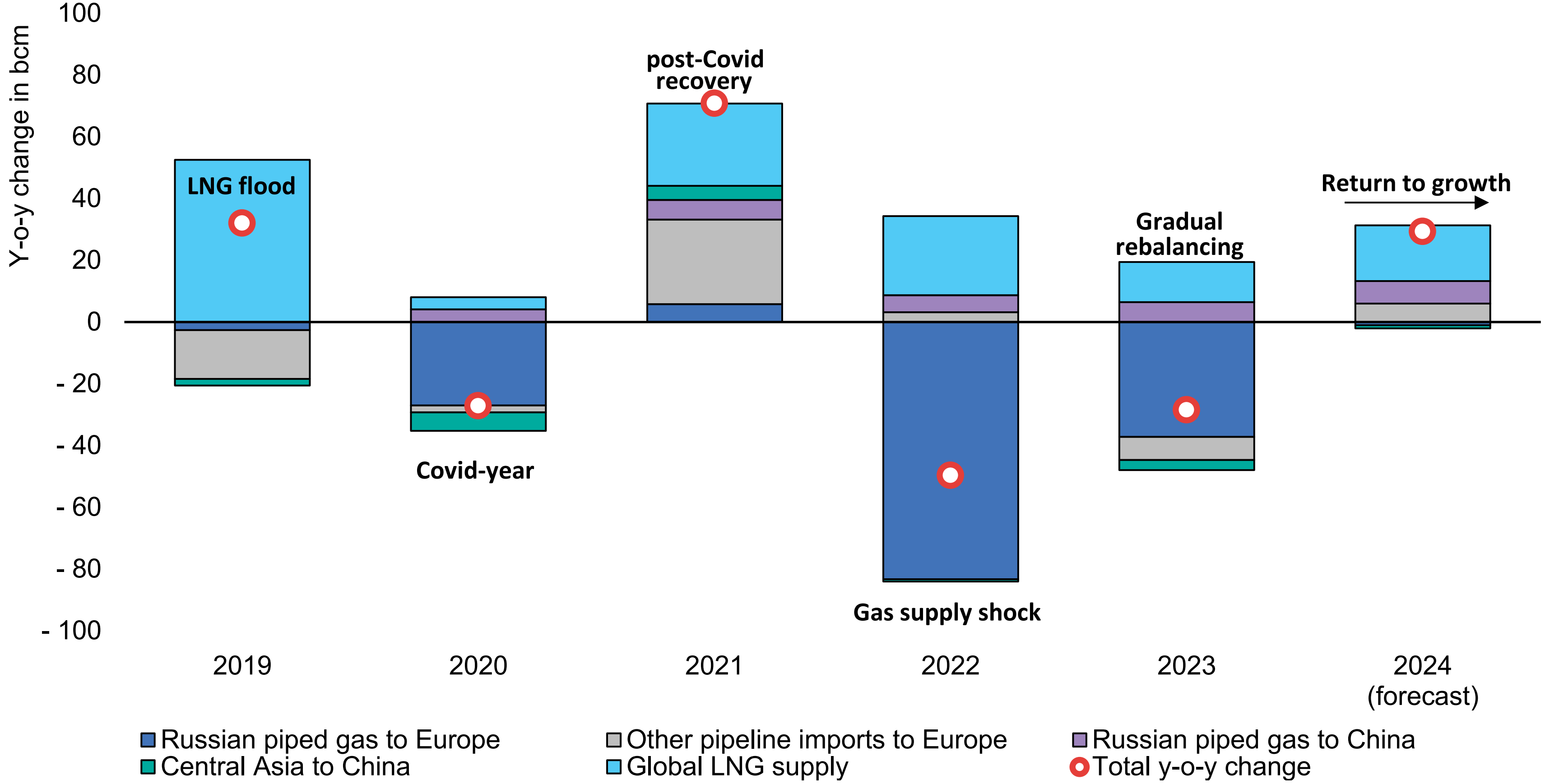
Natural gas markets are expected to return to growth in 2024

Global gas demand is forecast to grow by 2.5% in 2024. Demand growth is expected to be concentrated in **fast-growing markets in Asia Pacific** and gas-rich countries **in Africa and the Middle East**. The increase in gas demand will be supported by **industry**, as well as the **residential and commercial sectors** – assuming a return to average winter weather conditions following mild seasonal weather in 2023. **Gas-to-power** demand is forecast to increase only marginally, as higher gas burn in the Asia Pacific region, North America and the Middle East is expected to be partly offset by the continued reductions in Europe.

Demand growth in key markets in Asia and Europe will be capped by the **limited increase in global LNG supply**, which is expected to grow by a mere 3.5%. However, this forecast comes with an **unusually wide range of uncertainty**. Potential start-up delays at new liquefaction plants, a tense geopolitical context, worsening feedgas issues at specific legacy projects and risks related to shipping all represent downward risks to the current outlook, which could fuel price volatility through 2024.

Global natural gas trade is expected to return to growth in 2024

Year-on-year change in key piped natural gas trade and global LNG supply, 2019-2024



Key gas policies and market trends in 2023

Natural gas prices moderated significantly in 2023…

Following the all-time highs reached in 2022, natural gas prices moderated significantly across all key markets in 2023. The steep demand declines recorded in Europe and mature Asian markets provided downward pressure on gas prices. Correlation between Asian and European prices continued to be strong amid an increasingly globalised gas market.

In **Europe**, TTF month-ahead prices declined by almost 70% compared with 2022 to average USD 13/MBtu in 2023, still two and a half times higher than their five-year average during 2016-2020. The steep demand reductions, together with lower gas storage injection needs and healthy LNG inflows, softened natural gas prices despite the continued decline in Russian piped gas deliveries to the European Union (down by 60% y-o-y). **Price volatility remained high**, averaging over 100% in 2023, its highest level on record with the exception of 2022. Tight gas supplies, geopolitical tensions and unplanned outages fuelled price volatility throughout the year. The summer–winter spread on TTF stood at USD 5/MBtu, more than five times higher than its ten-year average, reflecting the risk premium attached by market participants to winter contracts.

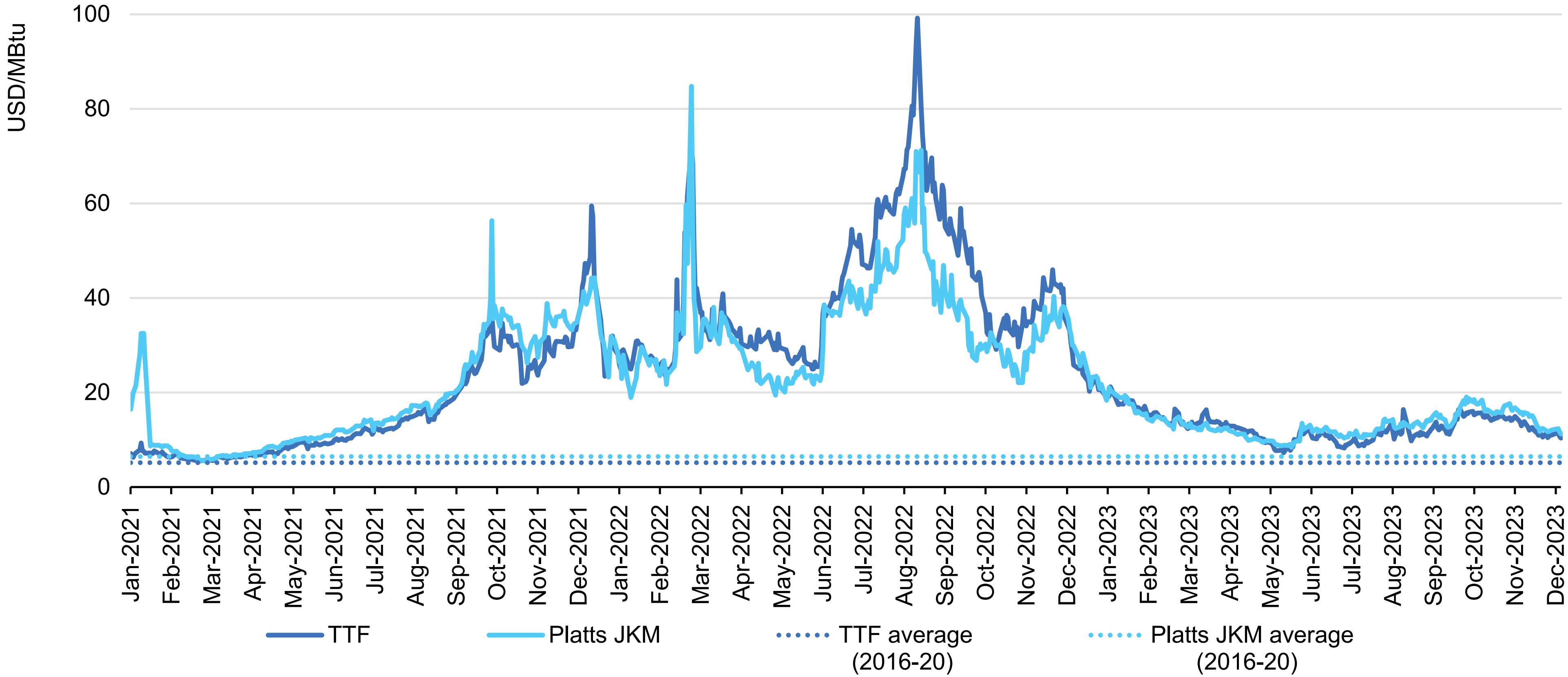
Asian spot LNG prices followed a similar trajectory. Platts JKM prices declined by 60% compared with 2022 and averaged USD 14/MBtu – more than the double their five-year average during 2016-2020. Improving LNG supply availability and lower competition for LNG from Europe softened prices. Price volatility moderated from an all-time high of 160% in 2022 to an average of 75%, remaining well above the 35% average displayed during 2016-2020. Similarly to the European market, heightened volatility reflected tight supply fundamentals, risks related to strikes at LNG plants, geopolitical tension and congestion on the Panama Canal in Q4.

Platts JKM regained its premium over TTF in the second half of 2023. High European inventory levels and continued demand reductions drove TTF prices below Platts JKM, with the northeast Asian marker displaying a premium of USD 1.5/MBtu over European hub prices in the second half of 2023. This incentivised stronger LNG flows towards Asian markets ahead of the 2023/24 winter season. Despite the strong volatility displayed both on the Asian and European markets, **the correlation between TTF and Platts JKM remained strong** and averaged close to 0.9. This reflects the interconnected nature of regional import markets amid the growing share of destination-flexible LNG supplies.

In the **United States**, Henry Hub month-ahead prices fell by 60% compared with 2022 to average USD 2.7/MBtu – aligned with their five-year average during 2016-2020. Strong domestic production together with milder winter temperatures moderated natural gas prices. Price volatility remained above average, supported by the higher share of natural gas in power generation.

…albeit remaining well above historical averages in Asia and Europe

Key Asian and European natural gas prices, 2021-2023

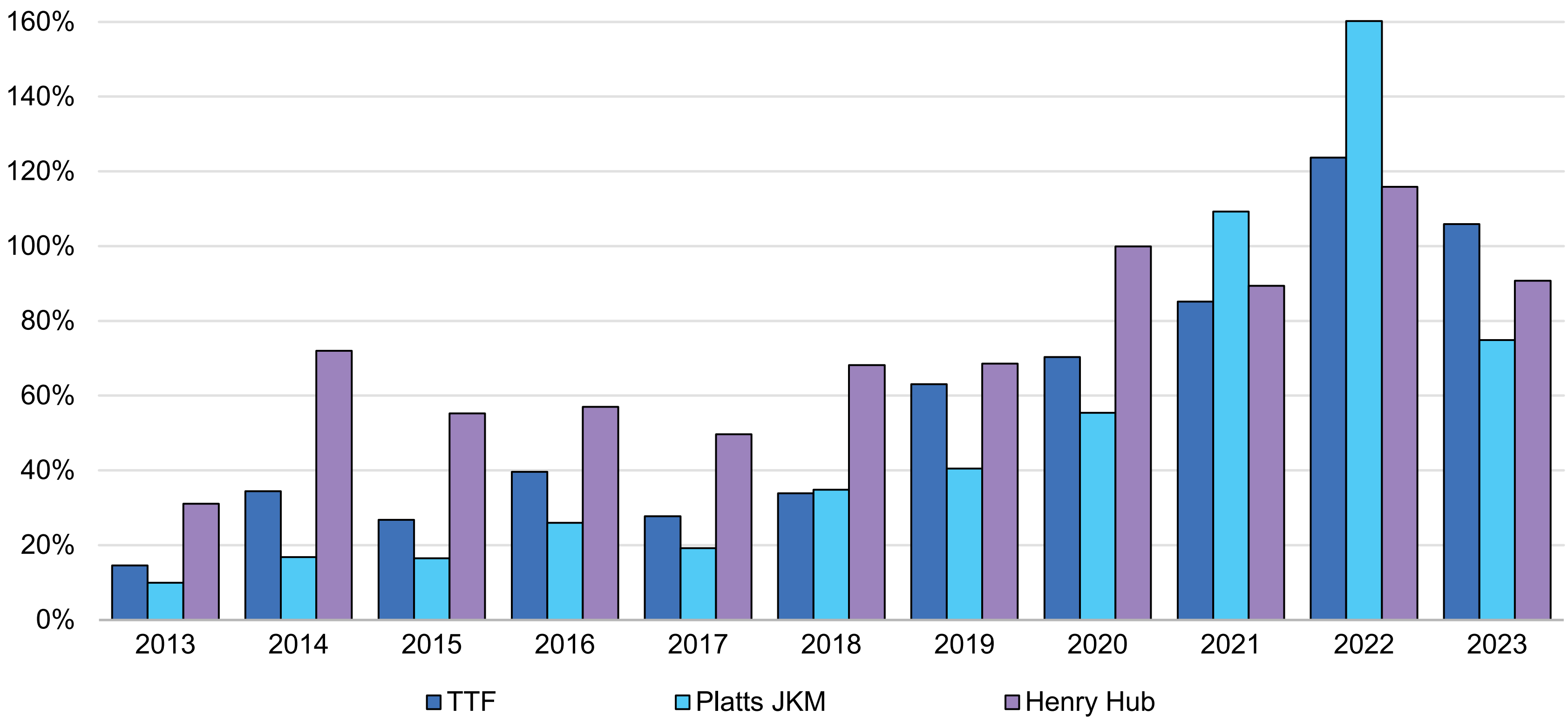


Note: TTF and Platts JKM average prices take 2016-20 as the reference period.

Sources: IEA analysis based on CME Group (2023), Dutch TTF Natural Gas Month Futures Settlements; CME Group (2023), LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2023), Henry Hub Natural Gas Spot Price; ICIS (2023), ICIS LNG Edge; Powernext (2023), Spot Market Data.

Heightened price volatility lingered into 2023 amid tight supply fundamentals

Annual average of historical price volatility across key gas markets, 2013-2023



Sources: IEA analysis based on CME Group (2023), Dutch TTF Natural Gas Month Futures Settlements; CME Group (2023), LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2023), Henry Hub Natural Gas Spot Price; ICIS (2023), ICIS LNG Edge; Powernext (2023), Spot Market Data.

Hub liquidity improved across all key gas markets in 2023

Natural gas hubs enable market participants to trade gas in open, competitive gas markets. Trading is carried out either over the counter (**OTC**) or through **exchanges**. Traded products range from short-term contracts to products with a delivery horizon several years ahead (derivatives). Derivatives allow market participants to develop sophisticated risk management strategies. **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, enhances supply security and enables price discovery. One metric used to assess liquidity is the **churn rate**, which measures how many times a unit of gas is exchanged before being delivered to end consumers. A churn rate above 10 usually indicates a liquid market.

Hub liquidity declined across all key gas markets in 2022. The sharp increase in natural gas prices, accompanied by high volatility, drove up margin requirements posted by central counterparties.[1] This in turn increased the cost of holding positions and led to liquidity strains, especially in the case of market players with more limited financial capabilities. **Margin calls moderated in 2023** on lower natural gas prices and softer volatility patterns, which led to a recovery in traded volumes and improved market liquidity.

In the **United States** gas volumes traded on **Henry Hub** fell by 5% in 2022 to their lowest level since 2015, while the churn rate fell to 40, its lowest level since at least 2012. The drop in gas prices throughout 2023 reduced trading costs and supported a 13% recovery in traded volumes, albeit remaining 3% below the average between 2017 and 2021. The churn rate rose by 11% to 44, standing 11% below the 2017-2021 five-year average.

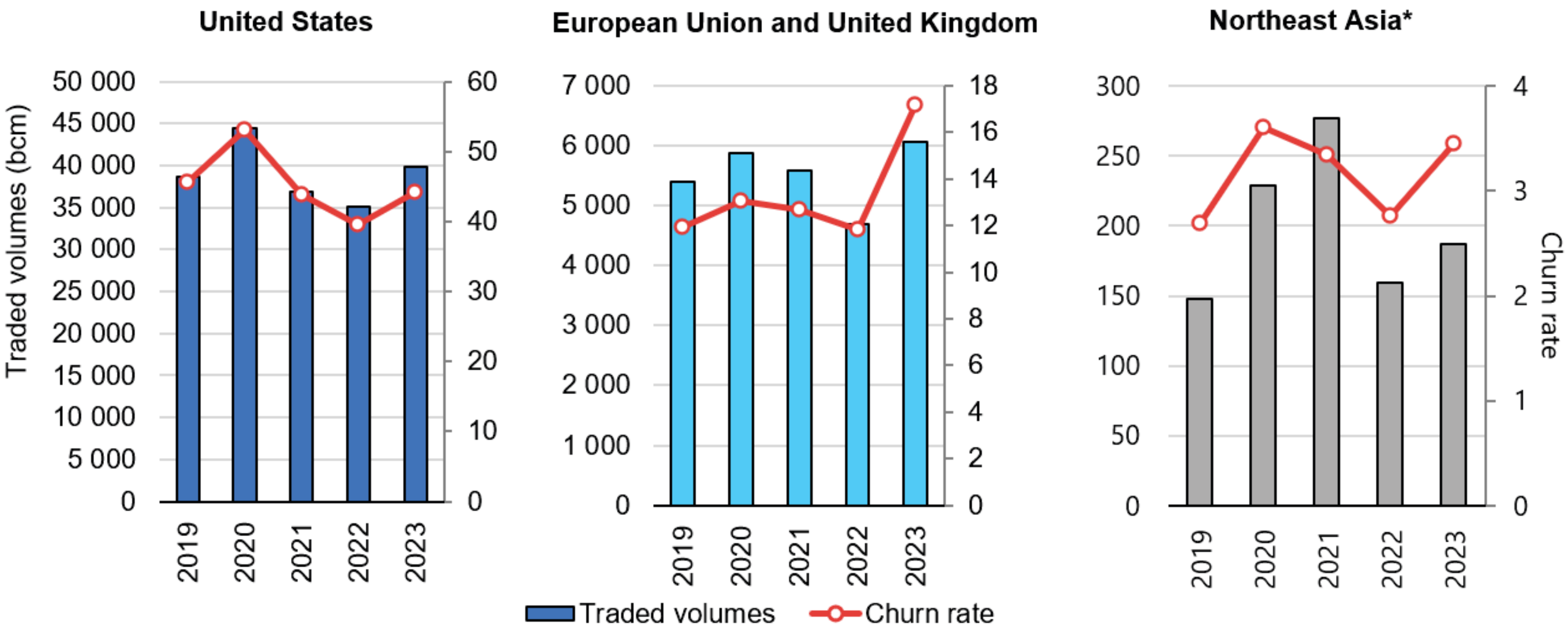
Following a steep decline of almost 20% in 2022, gas trading volumes in the **European Union and the United Kingdom** rose by close to 30% in 2023, reaching their highest level on record. This recovery was almost entirely led by the **Dutch TTF**, which saw its traded volumes rise by more than 40% compared to 2022. Consequently, its share of the total European gas trade rose from close to 75% in 2022 to just over 80% in 2023. The churn rate of the combined EU and UK gas markets rose by 45% y-o-y to an estimated 17, its highest level on record.

In **Asia**, trade in **ICE JKM** derivatives fell by 40% in 2022. Lower trading costs supported a partial recovery of 15% in their traded volumes in 2023. The churn rate remained low in the JKM area, although it improved compared to 2022, rising to 3.5.

[1] Central counterparties (CCPs) interpose themselves between the original counterparties to traded contracts and effectively bear the settlement risk of given transactions. CCPs require margins to cover the value of risk from their participants' outstanding transactions.

Gas trading volumes and churn rates recovered in 2023

Estimated traded volumes and churn rates across key natural gas markets, 2019-2023



* 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.

North America and the Middle East led the increase in LNG contracts in 2023

LNG contracting continued to experience strong momentum in 2023. Total contracted LNG volumes reached around 90 bcm, standing 10% above their three-year average during 2020-2022. Post-FID projects accounted for 70% of the total volumes contracted in 2023. The average duration of all LNG contracts signed in 2023 was around 15 years, highlighting the crucial role long-term contracts play in spreading investment risk between sellers and buyers. **European importers increased their contracting activity** following Russia's invasion of Ukraine, albeit their share of total contracts remains low when compared with Asian buyers. Destination flexibility remains a valued option, while pricing structures display a more diverse pattern, as market players pursue more sophisticated risk management strategies.

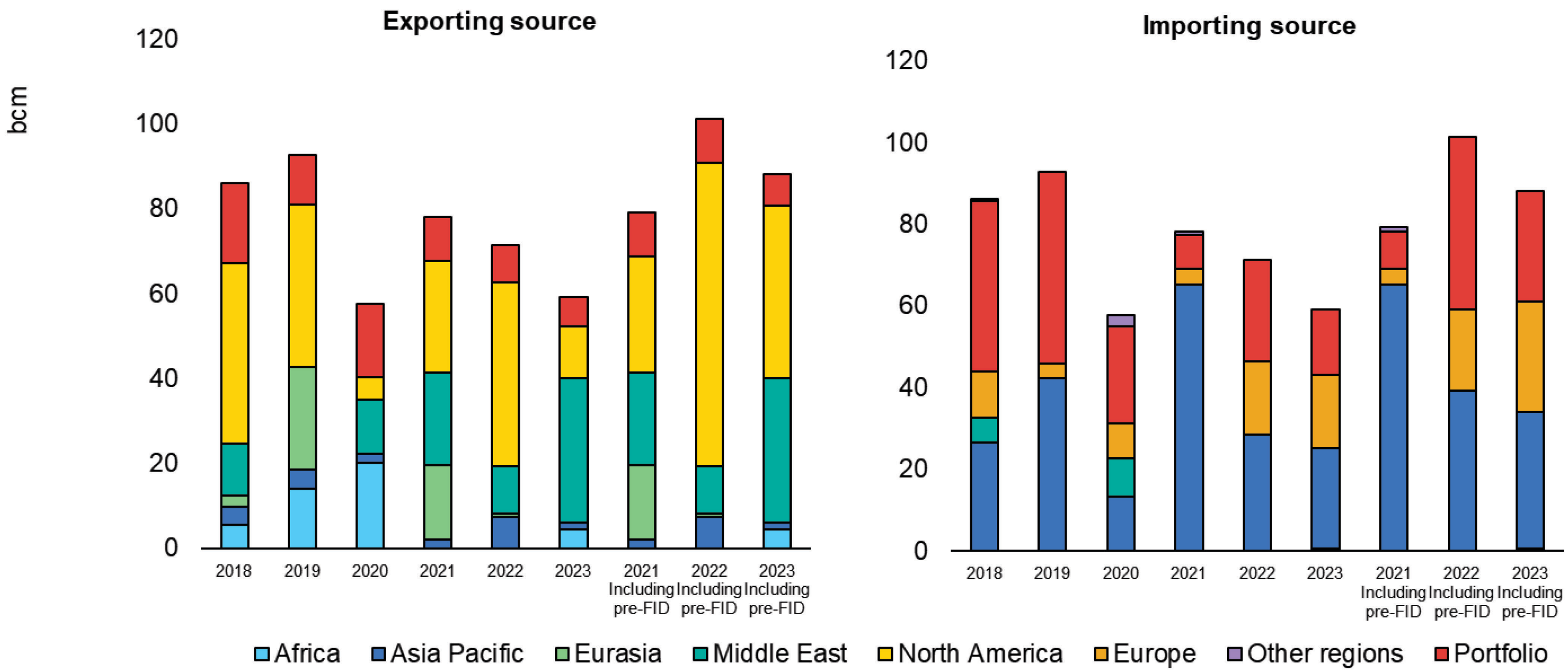
From a supplier's perspective, this strong contracting activity was primarily supported by **North America and the Middle East**. In particular, the United States and Qatar have been driving this trend, accounting for 34% and 26% of all contracted volumes in 2023 respectively. Considering only post-FID projects, these countries' share was 21% and 39% respectively. **From a buyer's perspective**, the contracting landscape continued to be dominated by Asia, Europe and portfolio players. Asian buyers accounted for about 38% of the total volumes contracted in 2023, and approximately 40% of contracts signed with post-FID LNG projects. **Europe accounted for 31% of the total volumes contracted in 2023** and for 30% of the contracts signed with post-FID projects – its highest share since at least 2016. This may indicate a preference to limit Europe's exposure to the spot market and secure a greater share of LNG supply under long-term contractual structures.

Contracts with destination flexibility accounted for over 40% of the total volumes contracted in 2022 and 2023 – a marked increase from an average of 23% in 2020 and 2021. Destination-fixed contracts are dominated by Asian buyers, with China alone accounting for around 40% of the total volumes contracted in 2023. In contrast, destination-flexible volumes are primarily contracted by European buyers and portfolio players, with a share of 21% and 73% in 2023 respectively.

Pricing mechanisms underpinning long-term LNG contracts are becoming more diverse and more complex. The volumes contracted under gas-to-gas indexed agreements have been increasing in recent years. This trend continued into 2023, primarily supported by contracts tied to US-based LNG projects and indexed to Henry Hub. Contracts and heads of agreements signed in 2023 also included agreements indexed to TTF and JKM as well hybrid mechanisms, indicating a move towards greater diversification in pricing mechanisms. Traditional oil-linked contracts remain favoured by Middle Eastern suppliers.

Europe's share of LNG contracting is on the rise

Volume of contracts concluded in each year split by exporting and importing source, 2018-2023



Notes: Contracted volumes used for the analysis are associated with confirmed export projects that have taken FID, except 2021, 2022 and 2023, which include contracted volumes from pre-FID export projects. 2023 represents volumes signed by the end of December 2023. Portfolio volumes are contracted by a market player who may source product from one or multiple regions to fulfil contractual obligations.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Supply security concerns remained a key driver behind gas policies in 2023

The global energy crisis triggered by Russia's invasion of Ukraine put **natural gas supply security at the forefront of energy policymaking**. Policy measures and new regulations enacted in 2022 reinforced gas supply security in key import markets and were complemented by new instruments in 2023.

The European Union launched its **Joint Gas Purchasing mechanism**, while Japan introduced the **Strategy LNG Buffer** system ahead of the 2023/24 winter season. **Singapore** announced plans to establish centralised gas procurement for the power sector. **India** introduced a unified pipeline tariff system and is currently considering establishing a **strategic natural gas reserve** to enhance the resilience of its – increasingly import-reliant – gas market. **China** continued to expand its natural gas storage capacity and released new draft policy guidelines on the future of natural gas use, gas infrastructure development and supply security.

The European Union launched its Joint Gas Purchasing mechanism

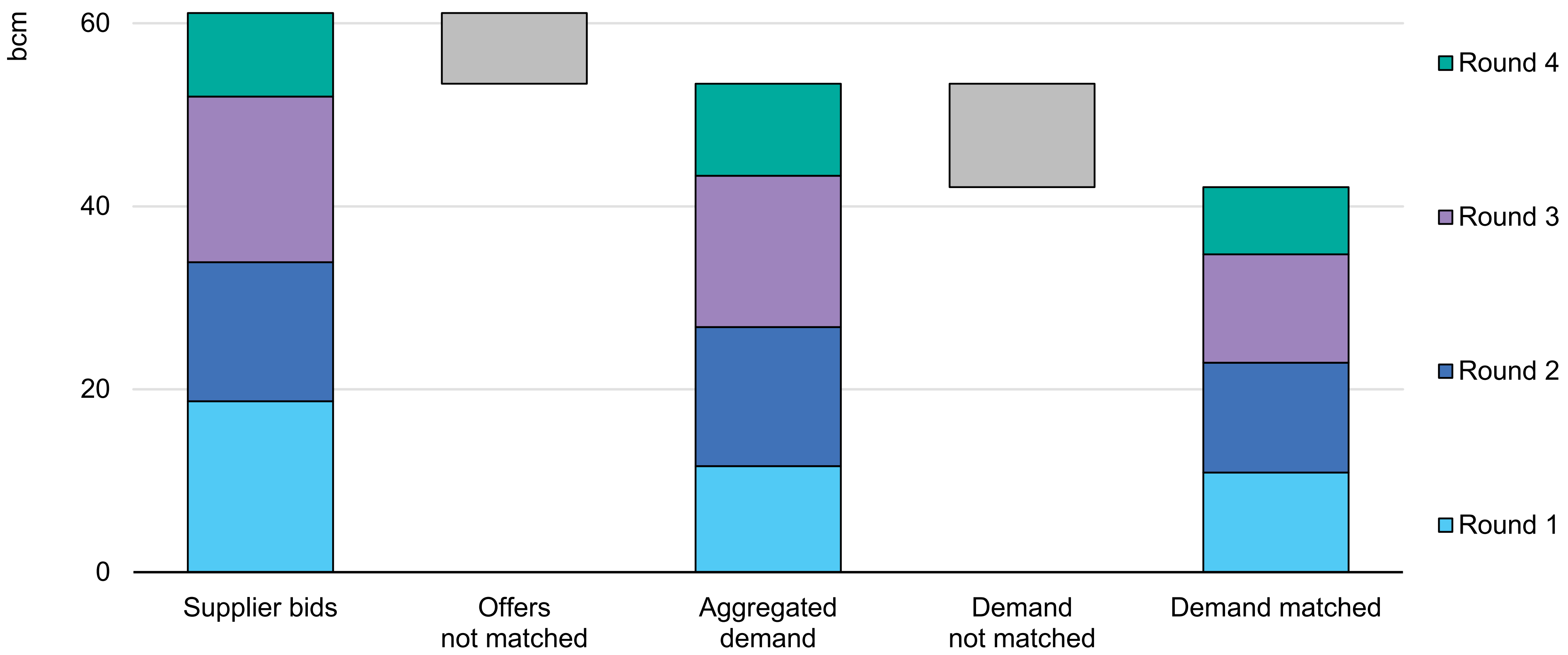
The European Union adopted a regulation in December 2022 to enhance solidarity through the better co-ordination of gas purchases. The **Joint Gas Purchasing mechanism** was launched in April 2023 with the aim of making use of the European Union's collective market power to negotiate better prices with international suppliers. The mechanism establishes a **two-step system**:

- **Demand aggregation** via the AggregateEU platform (participation is voluntary, except for volume requirements equivalent to 15% of gas storage filling needs or around 13.5 bcm).
- **Joint purchasing**: following the matching of demand with supply via the platform, companies can voluntarily conclude contracts with gas suppliers, either individually or jointly (through consortiums).

Since the launch of the mechanism, **four tendering rounds** were organised in 2023. Overall, almost 60 bcm of gas demand was aggregated from European companies in the first four rounds and close to 70 bcm of gas was offered by international suppliers. In total, 45 bcm of gas demand was matched with supply via the AggregateEU platform (equating to almost 15% of EU gas demand). **Commercial contracts** are concluded outside the mechanism, and no information has been publicly disclosed on the actual contracted volumes or price levels (to ensure confidentiality). At the end of November 2023 the European Commission proposed a 12-month prolongation of the three emergency measures introduced in 2022, including the Joint Gas Purchasing mechanism. At the end of December 2023 the European Council approved the Commission's proposals and adopted the prolongations.

AggregateEU matched over 40 bcm of gas demand and supply in 2023, equating to close to 15% of EU natural gas demand

Supplier bids, aggregated demand and matched demand via AggregateEU in 2023



Sources: IEA analysis based on European Commission (2023), Joint gas purchasing to increase energy security for Europe (Factsheet); European Commission (2023), Remarks by Executive Vice-President Šefčovič on the results of the third joint EU gas purchasing tender.

Singapore is set to centralise gas procurement for the power sector

Singapore announced in October 2023 plans to **centralise natural gas procurement** for the country's power sector in the wake of the global energy crisis and heightened market volatility. **Gas and electricity supply security are closely interlinked** in Singapore, with natural gas accounting for 95% of the country's power generation mix.

According to the assessment of Singapore's Energy Market Authority (EMA), **power generation companies** (gencos) contributed to the high electricity price volatility experienced in 2022 as they reduced their gas procurement volumes when natural gas prices were high. In addition, gencos were reluctant to sign long-term gas supply contracts – with pricing mechanisms ensuring greater price stability – due to the uncertainties facing natural gas in the long term.

Against this background, Singapore's Ministry of Trade and Industry and the EMA announced the establishment of a new entity (Gasco) in 2024. **Gasco will centralise future procurement of natural gas for the power sector** by aggregating gas demand from gencos. Initially, Gasco will procure the incremental gas volumes needed for the power sector. Once implemented, centralised procurement will apply to all future gas demand from the power sector, including the renewal of gas contracts. Nevertheless, the centralised gas procurement system will not impact existing contracts between gencos and their suppliers. Before the establishment of Gasco in 2024, EMA will launch a consultation with the industry.

Japan launched the Security Buffer LNG system ahead of the 2023/24 winter season

Japan's Ministry of Economy, Trade and Industry (METI) launched the **Strategic Buffer LNG** (SBL) ahead of the 2023/24 winter season. Under this system, METI designates private operators with high LNG procurement capacity as companies authorised to handle SBL operations. In the event of a contingency that could hinder LNG supply, the government will instruct the designated companies to sell their LNG cargoes to utilities in Japan facing the risk of supply disruption. The government will compensate the designated operator for any losses caused by the instructed trade. **JERA** was designated as the first supplier under Japan's SBL in November 2023. Under the SBL system, the company secured one LNG cargo per month during Japan's peak winter months over December 2023-February 2024. Looking ahead, Japan is considering **expanding the system** through the entire year and to quadruple the volumes held under the SBL to a minimum of 0.84 Mt/yr (or 1.1 bcm/yr) by the mid-2020s.

Outside the framework of the SBL, **JERA and Korea's KOGAS** signed a memorandum of understanding in April 2023 on closer co-operation in LNG trading, with the aim of enhancing stable energy supplies to Japan and Korea.

India simplifies natural gas pipeline tariffs and plans to build strategic gas storage

India continued to advance gas market reforms in 2023. The country introduced a unified pipeline tariff system on 1 April, which could benefit consumers located far from domestic gas supply sources and/or LNG terminals. In addition to the market reforms, India is considering establishing strategic gas reserves to enhance gas supply security.

Gas tariff reform to boost transparency and remote access

The Petroleum and Natural Gas Regulatory Board (PNGRB) introduced the Unified Tariff (UFT) policy in April 2023 to create a single, consistent and fair tariff structure for natural gas transport across the country. The UFT policy will apply to a network of 21 pipelines, representing around 90% of pipelines in operation or under construction.

The price of transporting gas consists of two components:

The **unified tariff** is a fixed charge determined by the PNGRB and based on the levelised cost of service of the entire pipeline network, and is revised periodically to reflect the changes in pipeline costs and utilisation.

The **zonal factor** is variable and depends on the tariff zone. There are three tariff zones: the first up to 300 km from the gas entry point, the second between 300 km and 1 200 km and the third beyond 1 200 km. The zonal factors for the three zones are 0.25, 0.5 and 1.0 respectively.

The **zonal tariff**, corresponding to the fee paid by the shipper to the pipeline operator for the transport of gas, is calculated by multiplying the unified tariff by the zonal factor.

The UFT policy aims to create a more stable, competitive and transparent pricing regime, which should benefit both gas supply and demand. It is expected to assist the government in achieving the "One Nation One Grid One Tariff" model.[2]

Gas storage could enhance India's gas supply security

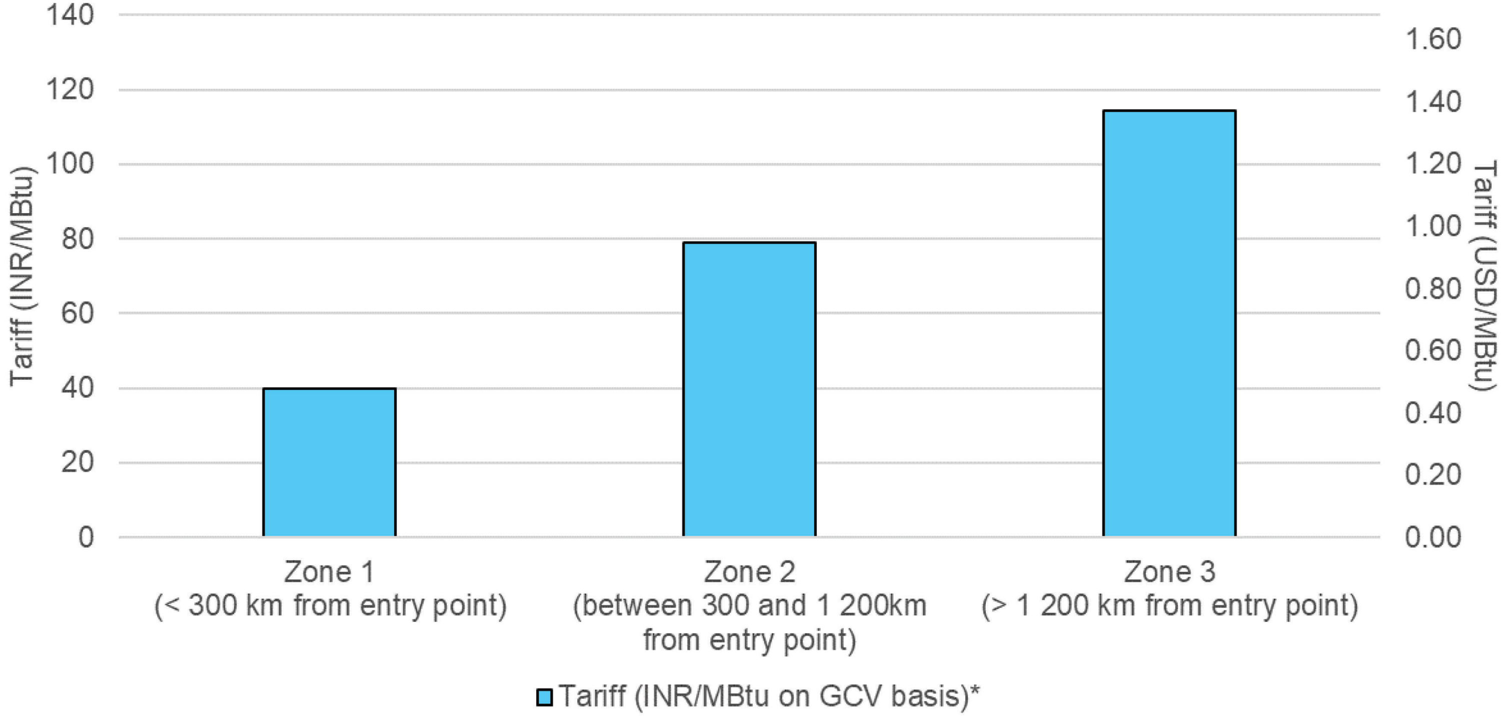
India has no underground storage sites and limited LNG storage capacity (1.5 bcm). In May 2023 the country's Energy Transition Advisory Committee (ETAC) suggested the development of strategic gas storage to strengthen the country's energy supply security and reduce price volatility. According to media reports, in November 2023 India's government requested national oil and gas companies[3] to prepare a feasibility study on the potential development of gas storage facilities with a capacity of 3-4 bcm.

[2] "One Nation One Grid One Tariff" refers to the integration of the regional grids into a national grid and the ambition to increase the share of natural gas in the primary energy mix to 15% by 2030, from the current level of around 6%.

[3] Oil and Natural Gas Corp. (ONGC), Oil India Limited and GAIL.

By introducing a new tariff structure, India aims to achieve a single gas market and encourage funding for gas infrastructure development

Unified gas pipeline tariff by zone, India, 01 July 2023-31 March 2024



* Includes additional goods and services tax of INR 0.02/MBtu on settlement amount between pipeline entities.

Note: GCV = gross calorific value.

Source: IEA analysis based on Petroleum and Natural Gas Regulatory Board Tariff Order, TO/2023-24/04, dated 27 June 2023 with effect from 1 July 2023.

China refocuses its policy setting for “orderly growth in natural gas”

In 2023 China continued natural gas pricing reforms and released draft policy guidelines on the **future use of gas** with a renewed focus on **supply security**. Past emphasis on ramping up the share and role of gas is now giving way to a more tempered approach of “orderly growth in natural gas demand”. While gas is still put forward as a bridge fuel in the Chinese economy, managing demand growth has gained importance.

Among the key measures, **policy reform has targeted city gas pricing**. Under the new rules, distributors can more freely adjust retail tariffs in line with sourcing costs, although local authorities still exercise a degree of control over pricing. Overall, these adjustments are expected to improve distributor balance sheets and to better communicate pricing signals to retail gas consumers, as had previously been done for industrial and commercial consumers.

In September 2023 **China’s National Energy Administration released a draft version of the Natural Gas Utilisation Policy**, setting out the guiding principles for gas market development in the coming years. The previous version of the policy (published in 2012) accompanied a step change in Chinese gas demand – particularly over the second half of that decade – as coal-to-gas substitution measures took effect and overall energy demand grew.

The draft policy redefines priority sectors for gas use, scaling back the deployment of gas in sectors that have been a source of supply tensions in the past. As such, more explicit rules are placed on coal-to-gas switching in **residential and commercial heating**, notably in areas requiring greater grid buildout or where gas affordability is an issue, avoiding a repeat of winter 2017/18 supply shortfalls.

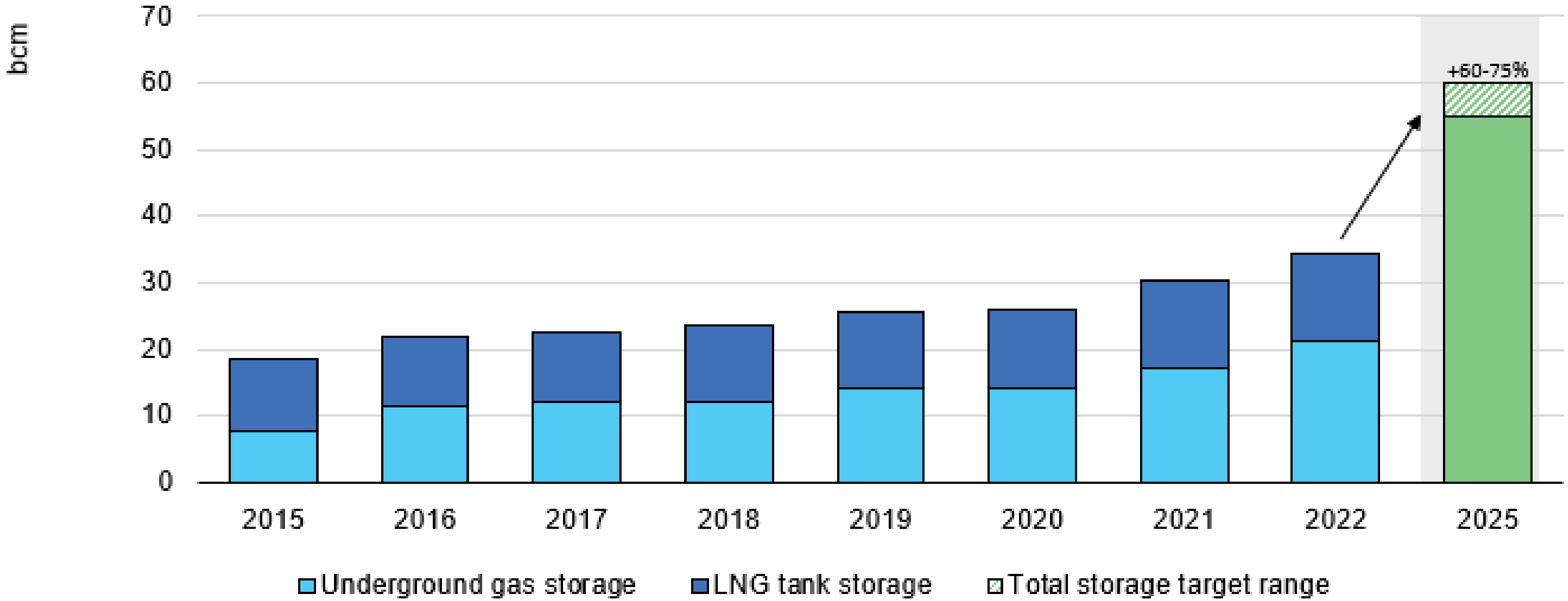
Natural gas for transport would now be focused on heavy goods and inter-city passenger transport. The draft policy also proposes less indiscriminate **gas-fired power build-out**, focusing resources on peak-shaving capacity and projects integrated with renewable developments, and sidelining projects in coal-dominated basins. In **industry**, segments meeting interruptibility requirements remain priority categories, and gas-based chemicals production (methanol) has been moved from “prohibited” status to “restricted” status, opening the door for deeper coal-to-gas substitution over time.

Importantly, the draft policy also calls for the development of **demand-side management** and the acceleration of import, storage and transport infrastructure deployment. This aligns with China’s target to **more than double the country’s gas and LNG storage capacity** to 55-60 bcm by 2025.

In December 2023 China’s National Development and Reform Commission announced the **simplification of gas transport tariffs**. From January 2024 the reform sets up four regional transport rates to replace the 20 previously in place and is expected to foster improved transparency and flexibility in domestic gas trade.

Natural gas storage development remains key to China's gas market growth strategy

Estimated natural gas storage capacity in China, 2015-2022, and target for 2025



Note: 2025 target based on China National Energy Administration National 2021 Gas Storage Capacity Construction Implementation Plan.
Sources: CEDIGAZ (2023), UGS Dataset; ICIS (2023), LNG Edge.

Gas market update

Global gas demand grew marginally in 2023 to remain below 2021 levels amid tight supply

Global gas demand grew by an estimated 0.5% (or 20 bcm) in 2023, not sufficient to recover the losses seen in 2022, when overall demand dropped by 1.5% (or 60 bcm). **Gas supplies remained tight in 2023**, as the increase in global LNG production (up 13 bcm) was not enough to offset the continued decline in Russian piped gas deliveries to Europe (down 38 bcm). **Global gas demand returned to growth in the second half of 2023**, primarily supported by North America, the fast-growing markets of Asia, the Middle East and Africa. Industry emerged as the most important driver behind demand growth, followed by the power sector. Demand in the residential and commercial sectors declined amid milder winter weather conditions and energy-saving efforts.

Natural gas consumption in **North America** grew by over 1% (or more than 10 bcm) in 2023, primarily driven by higher gas burn in the region's power sector. In the United States domestic natural gas output rose by 4% (or 40 bcm) to reach an all-time high of 1 065 bcm. This strong growth in supply, together with mild winter weather, provided downward pressure on gas prices, which plummeted by 60% compared to 2023. Lower gas prices supported further coal-to-gas switching in the power sector and drove up the share of natural gas in the US power mix to an all-time high of 42% in 2023. Ample domestic gas supply enabled the United States to further increase its LNG exports (up by 10%) and to become the world's largest LNG supplier in 2023.

Natural gas demand in **Central and South America** declined marginally compared to 2022. Healthy hydro availability in Brazil depressed gas burn in the power sector, while a milder southern hemisphere winter weighed on space heating requirements in Argentina. Preliminary data indicate that gas demand returned to growth in H2 2023, supported by the industrial and power sectors.

Following a 1.5% decline in 2022, gas demand in the **Asia Pacific** region returned to growth in 2023, increasing by an estimated 2.5%. This was largely driven by **China and India**, while gas demand in the region's mature markets (Japan and Korea) continued to decline amid lower electricity consumption and improving nuclear availability. Gas demand in China increased by an estimated 7% (or 26 bcm) on the back of higher gas use in the power and industrial sectors. **China regained its position as the world's largest LNG importer**, with the country's LNG inflows rising by 14% (or 12 bcm) in 2023 – albeit remaining below the record levels reached in 2021. Gas consumption in **emerging Asian markets** displayed varied patterns in 2023, as lower domestic gas production and a still relatively high LNG price environment limited demand growth in the region's price-sensitive markets.

Natural gas demand in **OECD Europe** fell by 7% (or 35 bcm) in 2023 to its lowest level since 1995. The power sector alone accounted for 75% of the demand reduction as lower electricity consumption together with the continued expansion of renewables and improving nuclear availability weighed on gas-fired power generation. Distribution network-related demand continued to decline amid lower gas use for space heating in the residential and commercial sectors. Non-weather-related factors contributed to the bulk of the demand reduction in these sectors. Natural gas use in industry started to recover in H2 2023, albeit remaining well below its 2021 level. Following a surge of 60% in 2022, Europe's LNG imports declined marginally in 2023, as lower gas demand and high storage levels eased the pull on LNG imports in H2 2023.

In **Eurasia** natural gas demand rose by an estimated 1% compared to 2022. The region's gas production dropped by around 3% (or close to 30 bcm), primarily due to lower gas output in Russia and Uzbekistan. Russia's natural gas production declined by an estimated 5% (or over 30 bcm) amid lower piped gas exports to the European Union. In Uzbekistan, natural gas production declined by close to 10% (or 5 bcm) in 2023 due to the continued deterioration of the upstream sector. In contrast, natural gas production grew by an estimated 7% (or 6 bcm) in Turkmenistan and rose by 6% (or 1.5 bcm) in Kazakhstan. Azeri gas output grew by 4% (or 1.5 bcm) in 2023, partly supported by higher piped gas deliveries to the European Union.

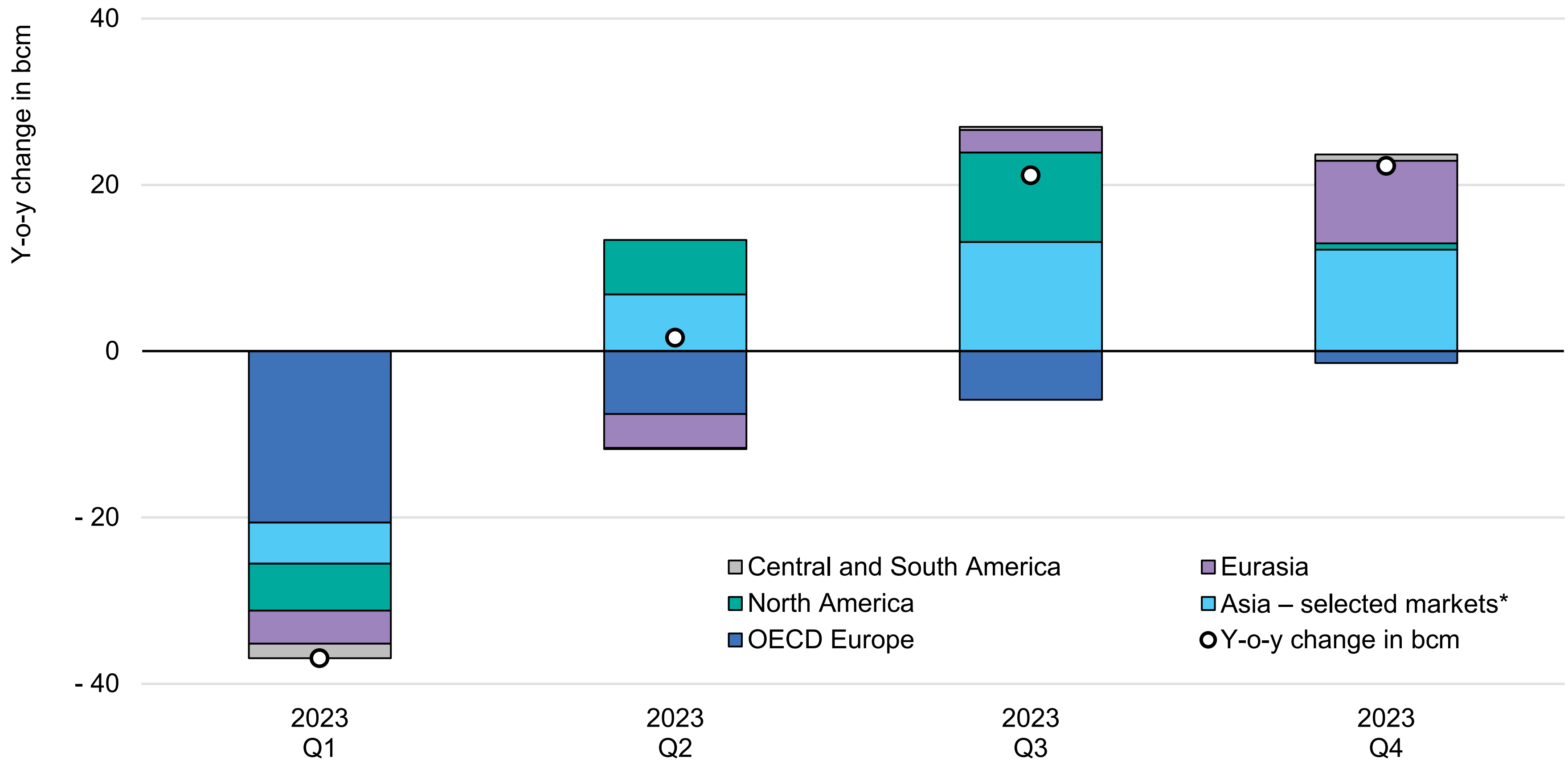
Natural gas demand in the **Middle East** expanded by an estimated 2%, supported by higher domestic production and driven by stronger gas use in the industrial and power sectors. In Iran natural gas consumption increased by around 3%, driven by the residential and commercial sectors as well as stronger gas-to-power demand.

In Saudi Arabia stronger gas burn in the power sector reduced oil-based power generation, which declined by an estimated 5% y-o-y in Q1-Q3 2023, leaving more space for natural gas. Omani gas consumption rose by 5% y-o-y in the first seven months of 2023 on the back of higher gas use in industry. Natural gas demand in **Africa** rose by an estimated 3% y-o-y in the first eleven months of 2023. This was primarily supported by stronger demand from the power sector.

Global gas demand is forecast to grow by 2.5% (or 100 bcm) in 2024. We anticipate growth to be capped in import markets by the limited increase in global LNG supply, which is expected to expand by a mere 3.5% (or 18 bcm). The increase in gas demand is set to be supported by industry, as well as the residential and commercial sectors, assuming a return to average weather conditions after a mild winter in 2023. Gas demand in the Asia Pacific region is expected to expand by close to 4% compared to 2023, supported by industrial activity and higher gas use in the power sector. Gas consumption in North America is projected to grow by 1.5% and increase by a marginal 1% in Central and South America. In Europe natural gas demand is forecast to grow by 3% and remain almost 20% below its 2021 levels. While gas use in industry and for space heating is expected to recover, gas-fired generation is set to decline further. Gas demand in the gas-rich markets of Africa and the Middle East is forecast to increase by 3%. Eurasian gas demand is projected to grow by 2% amid higher demand in industry and the residential and commercial sectors.

Gas demand returned to growth across all key markets in H2 2023, except Europe

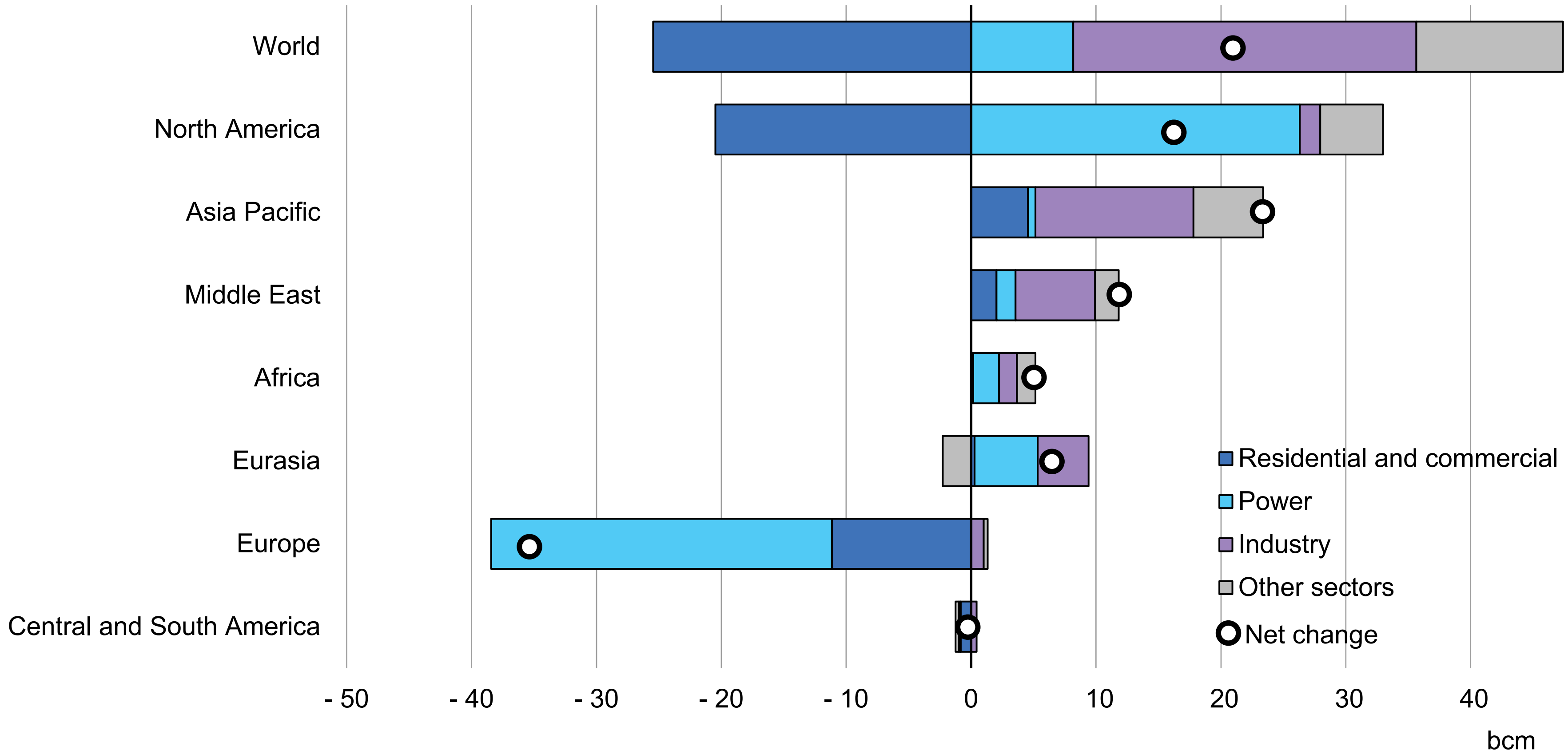
Estimated quarterly change in natural gas demand in key regions, 2022-2023



* Bangladesh, China, India, Indonesia, Japan, Korea, Malaysia, Pakistan, Philippines, Singapore and Thailand.

Industry and the power sector were the key drivers behind gas demand growth in 2023

Estimated change in natural gas consumption by region and sector, 2023 vs 2022



North American gas demand continued to grow in 2023, driven by record gas burn for power

Natural gas consumption in North America grew by an estimated 1% (or more than 10 bcm) in 2023, primarily supported by record high gas burn in the US power sector. Milder weather conditions in Q1 and Q4 weighed on space heating requirements both in Canada and the United States, limiting the expansion of gas demand. Gas demand in industry remained broadly flat amid a weak macro-economic environment.

In the **United States** natural gas consumption increased by an estimated 0.8% (or around 7 bcm) in 2023. Demand in the **residential and commercial sectors** declined by more than 7% (or over 15 bcm) as lower heating degree days depressed space heating requirements across Q1 and Q4 2023. In contrast, gas burn in the **power sector** continued to expand and rose by 6.5% (or more than 20 bcm) compared to 2022. Consequently, the share of natural gas in power generation increased from 39% in 2022 to an all-time high of 42% in 2023. This strong growth was primarily supported by coal-to-gas switching dynamics. The steep decline in gas prices (down 60% y-o-y) increased the cost-competitiveness of gas-fired generation vis-à-vis coal-fired power plants, which saw their production plummet by 20% compared to 2022. Lower hydro availability provided additional market space for gas-fired power plants, especially in the Northwest region. Natural gas demand in **industry** declined marginally compared with 2022 amid subdued economic activity. The US Manufacturing Purchasing Managers' Index (PMI) fell to 47 in 2023, its lowest annual average since 2009, indicating a contraction in manufacturing activity.

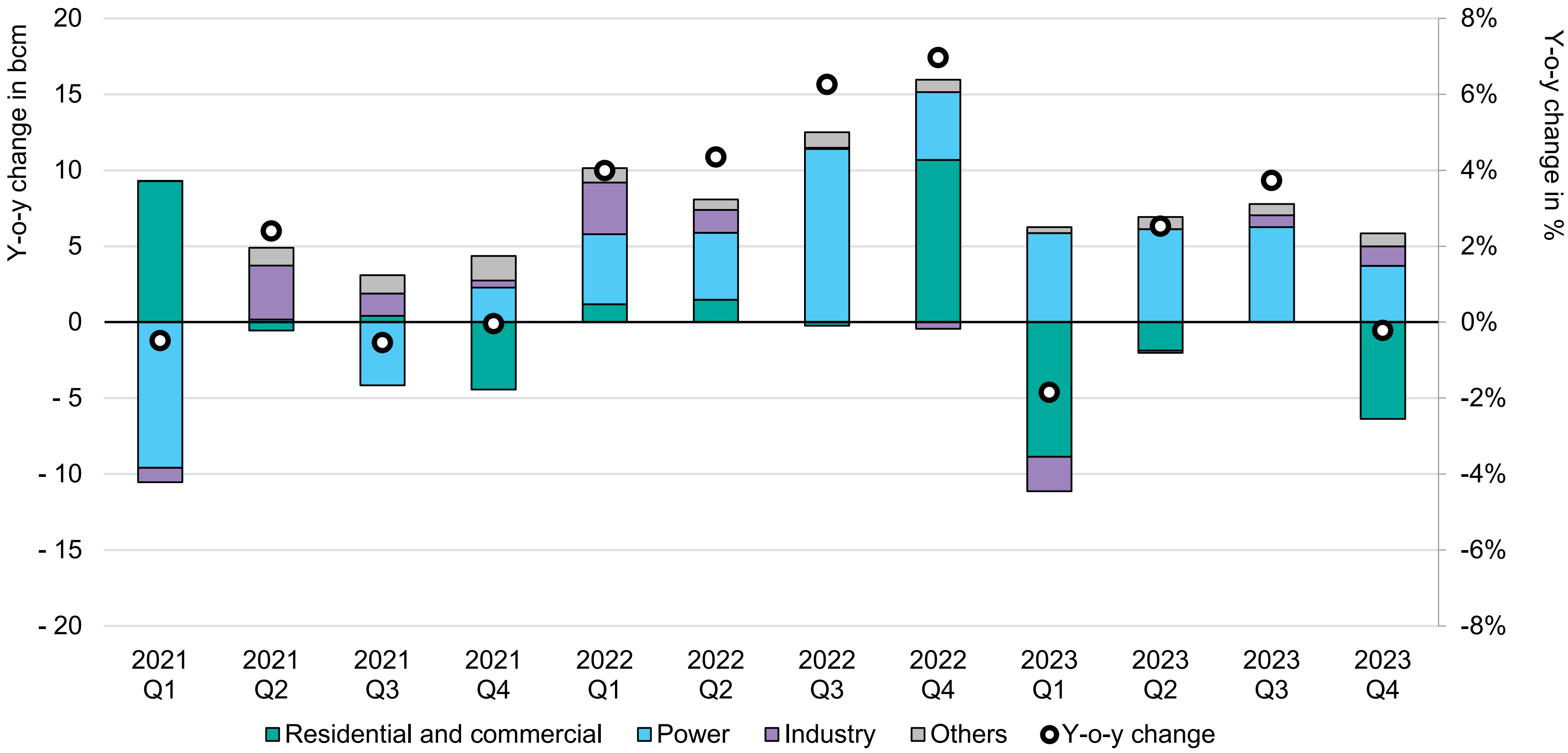
In **Canada** natural gas demand increased by an estimated 1% (or 1 bcm), primarily supported by higher gas burn in the power sector. Similarly to the United States, milder weather conditions weighed on gas use in the residential and commercial sectors, which declined by an estimated 9% in 2023 in the first ten months of 2023. Combined gas demand in the industrial and power sectors rose by close to 6% y-o-y during the same period of 2023, largely supported by stronger gas-fired generation at the expense of coal-fired power plants.

In **Mexico** natural gas consumption grew by an estimated 5% (or 4 bcm) in 2023 amid the continued expansion of gas-fired power generation. Higher gas demand was primarily met by stronger gas pipeline imports from the United States, which increased by an estimated 8% compared with 2022.

Natural gas demand in North America is expected to increase by just over 1% in 2024. Our forecast assumes a return to average weather conditions, which would increase gas use in the residential and commercial sectors. In contrast, gas-to-power demand growth is forecast to moderate following the strong gains experienced during 2022-2023. The continued expansion of renewables is set to weigh on gas-fired generation. Gas demand in industry is expected to decline marginally in a weak macro-economic environment.

US gas consumption increased in 2023 despite a decline in residential and commercial demand

Estimated quarterly change in gas demand, United States, 2021-2023



Sources: IEA analysis based on EIA (2024), Natural Gas Consumption; Natural Gas Weekly Update.

Lower gas-fired generation in Brazil depressed gas demand in Central and South America

Natural gas consumption in **Central and South America** declined by an estimated 1.5% (or just over 1.5 bcm) y-o-y in Q1-Q3 2023, primarily due to lower gas-fired generation in Brazil amid healthy hydro availability. The demand reduction was entirely concentrated in H1 2023, while the region's gas consumption returned to growth in Q3, when it increased by 1% compared to the same period in the previous year.

In **Argentina** – the region's largest gas market – natural gas consumption fell by 0.8% (or 0.25 bcm) in the first ten months of 2023. Gas demand in the **residential and commercial sectors** declined by 6% (or 0.7 bcm) y-o-y. Around 80% of this decline was during the southern hemisphere winter season (April-September), when milder weather conditions weighed on space heating requirements. In contrast, gas demand in **industry** rose by 4.5% (or 0.45 bcm) y-o-y in Q1-Q3 2023. Gas burn in the **power sector** increased by 0.8% y-o-y during the same period, despite higher hydropower output.

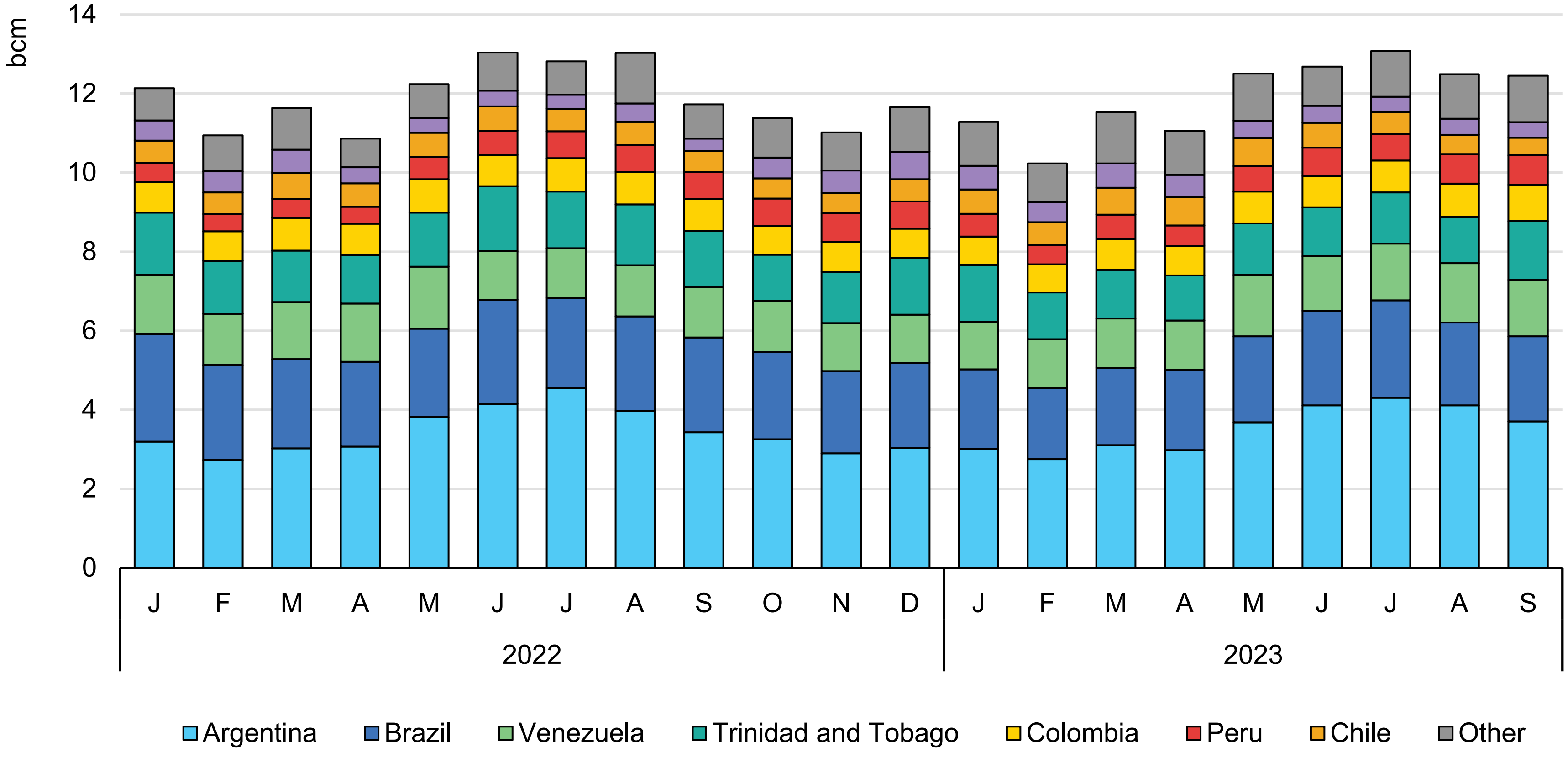
Natural gas consumption in **Brazil** fell by an estimated 9% (or more than 2 bcm) y-o-y in the first eleven months of 2023. Healthy hydro availability (up by 1%) and the continued expansion of wind and solar (together up by 45%) **significantly reduced the call on gas-fired power plants**. The decline in gas-fired generation was largely concentrated during the periods of higher hydro availability (Q1 and August-October). In contrast, lower hydropower output during April and July led to a temporary increase in gas-fired generation, highlighting the back-up role played by gas-fired power plants in Brazil's electricity system. As a consequence of lower gas demand, Brazil reduced its piped gas imports from Bolivia by 13% (or 0.7 bcm) y-o-y, while its LNG inflows dropped by 55% (or 1.5 bcm) y-o-y in the first eleven months of 2023.

In **Trinidad and Tobago** natural gas consumption declined by 3% (or 0.3 bcm) y-o-y in Q1-Q3 2023, amid lower gas burn in the power sector (down 2%) and reduced gas use in industry (down 3%). In **Venezuela** observed gas consumption remained close to 2022 levels in the first ten months of 2023. In **Colombia** gas demand rose by 4% (or 0.2 bcm) y-o-y in 2023, primarily supported by stronger gas-fired generation (up 20%) and higher gas use in the commercial sector (up 10%). Gas demand in industry declined by 3% y-o-y, largely offset by higher gas use in refining (up 7.5%). Gas demand grew strongly in **Central America** and the Caribbean markets, with their combined LNG imports surging by 35% in 2023.

Our **forecast** expects natural gas demand in Central and South America to increase by just 1% in 2024, after the declines recorded in the previous two years. While gas burn in the power sector is set to remain depressed amid the continuing expansion of renewables, the industrial sector is expected to provide room for natural gas demand growth.

Gas demand in Central and South America returned to growth in Q3 2023

Monthly natural gas consumption, Central and South America, 2022 and Q1-Q3 2023



Sources: IEA analysis based on ANP (2024), Boletim Mensal da Produção de Petróleo e Gás Natural; BMC (2024), Informes Mensuales; Central Bank of Trinidad and Tobago (2024), Statistics; CNE (2024), Generación bruta SEN; ENARGAS (2024), Datos Abiertos; ICIS (2024), ICIS LNG Edge; IEA (2024), Monthly Gas Data Service; JODI (2024), Gas Database; MME (2024), Boletim Mensal de Acompanhamento da Industria de Gás Natural; OSINERG (2024), Reporte diario de la operación de los sistemas de transporte de gas natural.

Natural gas demand in Asia returned to growth in 2023

Following a drop of 1.5% in 2022, natural gas demand in the Asia Pacific region returned to growth in 2023 and increased by an estimated 2.5%, offsetting the losses of the previous year. This growth was largely concentrated in H2 2023 and primarily driven by China, India and certain emerging Asian markets. In contrast, natural gas demand remained depressed in the mature markets of the region (Japan and Korea), as improving nuclear availability reduced the call on gas-fired power plants. Asia is set to remain the main driver behind global gas demand growth in 2024. The region's natural gas consumption is forecast to increase by 4% in 2024, accounting for almost 40% of incremental gas demand globally.

In 2023 **China**'s natural gas demand rose from the ashes of 2022, reinvigorated after the punishing effects of high global gas prices on the competitiveness of the fuel in the energy mix. Gas demand in China is estimated to have grown by 7% or approximately 26 bcm in 2023, principally driven by a recovery in industrial activity as Covid-related restrictions eased and global gas prices declined steadily throughout the year. The industrial sector accounted for approximately 40% of the country's total natural gas demand growth, buoyed by lower gas prices. Heavy and energy-intensive industry, sensitive to fuel prices, partially reversed the fuel switching away from gas that took place in 2022, while improving economic prospects also drove up overall energy demand in the sector. Lower gas prices, together with subdued hydro availability in H1 2023, supported stronger gas burn in the power sector, which recorded an increase of more than 6% y-o-y. Despite this growth, gas-to-power demand in 2023 remained slightly below pre-crisis levels given sustained competition from coal and the continuing expansion of wind and solar power generation. Residential and commercial gas consumption grew by approximately 8% in 2023, up from 2022 growth levels. Total Chinese gas demand growth is expected to ease slightly to 6% in 2024 as the recovery effect tapers and incremental gas demand increasingly relies on fundamentals and policy positioning. Gas demand in industry will continue to drive incremental volumes, but lower economic growth prospects compared to pre-crisis levels mean that the increase in the sector's gas demand is expected to moderate to 6%. Electricity demand growth lifts power sector gas burn by more than 6% and the effects of an expanding gas distribution grid helps keep residential and commercial demand growing at close to 6% in 2024.

In **Japan** natural gas consumption fell by approximately 8% in the first ten months of 2023, primarily due to lower gas burn in the power sector. Gas-fired power generation declined by about 10% y-o-y in the first nine months of 2023 due to a combination of factors. Milder weather conditions together with energy saving gains reduced electricity consumption, which declined by around 3% y-o-y in the first ten months of 2023. In addition, nuclear power output increased by an impressive 50% y-o-y in 2023, which together with higher renewable power generation reduced the call on gas-fired power plants. According to METI data, city gas sales to the industrial sector dropped by close to 10% y-o-y in the first ten months of 2023. Gas demand in the commercial and residential sectors fell by 6% y-o-y during the same period, amid milder weather conditions. After the steep demand drop recorded in 2023, this forecast expects natural gas demand to decline only marginally in 2024. While electricity consumption may recover, the restart of nuclear power plants and increased renewable power generation will continue to weigh on gas-to-power demand.

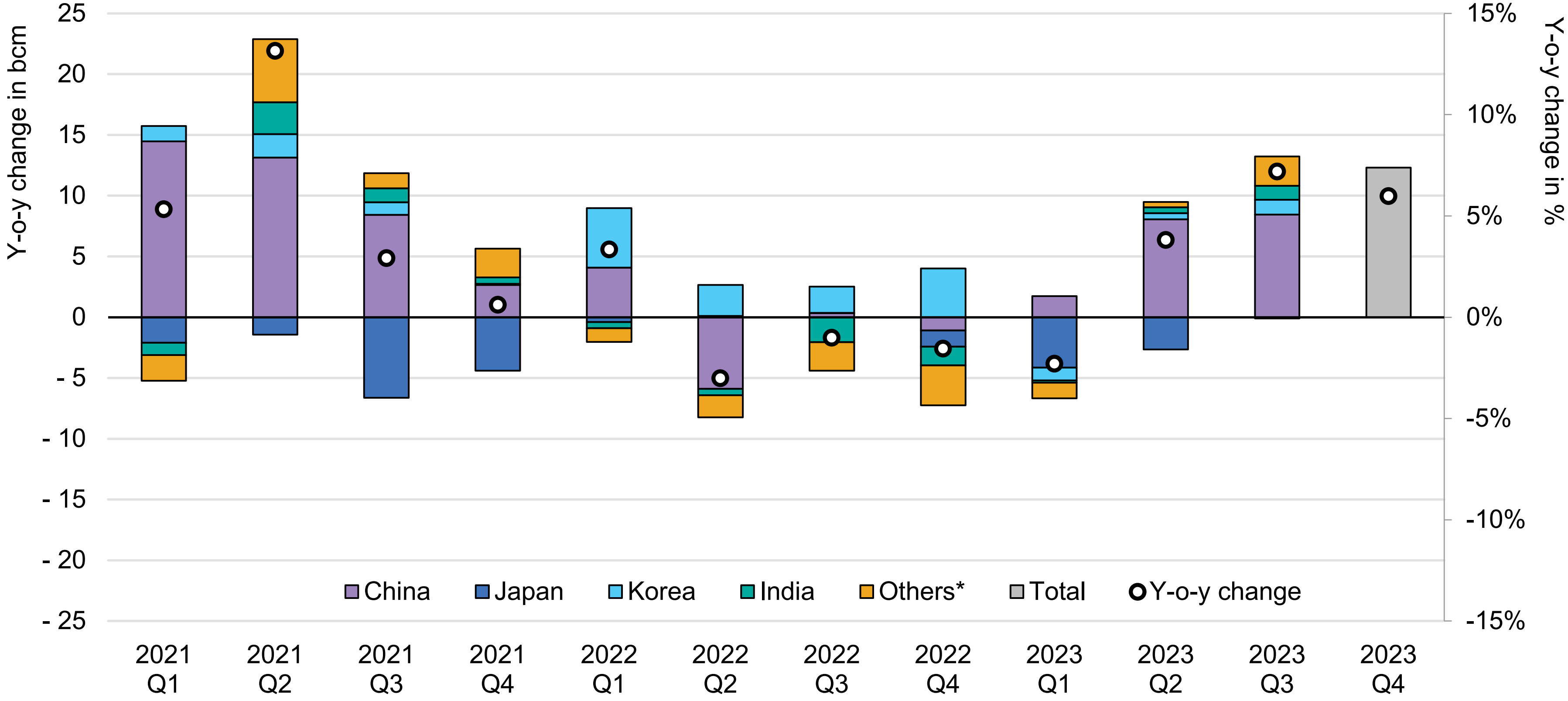
Korea's gas consumption fell by an estimated 3% in the first ten months of 2023. Similarly to Japan, higher nuclear availability and stronger renewable power generation depressed gas burn in the power sector, which dropped by 2% y-o-y in the first ten months of 2023. Gas demand in the city gas sector declined by close to 10% y-o-y amid milder weather conditions. Korea's gas demand is forecast to decrease by 2% in 2024, as gas-fired power generation continues to decline amid stronger renewable power output and improving nuclear availability. While gas demand in the industrial, commercial and residential sectors is expected to recover, it is more than offset by the declines in the power sector.

Following the 7% y-o-y decline observed in 2022, **India**'s primary gas supply rose by 5% y-o-y in 2023, according to the Petroleum Planning & Analysis Cell. Gas demand growth is primarily driven by the petrochemical, power generation, refinery and industrial sectors. Natural gas demand in India is expected to increase by 6% in 2024, mainly supported by higher gas use in industry (including in the fertiliser sector) and stronger gas burn in the power sector amid the development of its national pipeline grid and city gas infrastructure.

Emerging Asia's gas consumption increased by an estimated 2.5% y-o-y in the first eleven months of 2023, as lower LNG prices supported demand growth in the region's price-sensitive end-use sectors. Natural gas demand in **Thailand** grew by 6% (or 2.5 bcm) y-o-y. This was entirely driven by higher gas burn in the power sector, increasing by more than 12% y-o-y in the first eleven months of 2023. In contrast, gas use in industry continued to decline and fell by 3% y-o-y. Gas demand in **Bangladesh** declined by an estimated 1% y-o-y in the first ten months of 2023, as the increase in LNG imports (up by close to 20%) was not sufficient to offset the declines recorded in domestic natural gas production. The country continued to face rotating power cuts amid inadequate gas supplies. Gas demand in **Pakistan** fell by an estimated 1.5% y-o-y in Q1-Q3 2023. Similarly to Bangladesh, lower domestic gas production (down by 4%) was not offset by higher LNG imports (up by 7%), perpetuating a tight gas supply–demand balance and rotating power cuts. **Indonesia**'s gas demand grew by a strong 10% (or 3.5 bcm) y-o-y in the first eleven months of 2023, primarily supported by the power and industrial sectors. In **Malaysia** natural gas demand declined by an estimated 1% as lower gas production tightened gas supplies into the domestic market. Natural gas demand in emerging Asia is forecast to increase by close to 4% in 2024, primarily supported by the power and industrial sectors.

China drove Asia's natural gas demand recovery in 2023

Estimated quarterly change in gas demand, selected Asian markets, 2021-2023



*Others comprises Indonesia, Malaysia, the Philippines, Singapore and Thailand.

Sources: IEA analysis based on ICIS (2024), ICIS LNG Edge; CQPGX (2024), Nanbin Observation; JODI (2024), Gas World Database; PPAC (2024), 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.

European natural gas consumption dropped in 2023 to its lowest level since 1995…

Natural gas demand in OECD Europe fell by 7% (or 35 bcm) in 2023 to its lowest level since 1995. The decline was almost entirely concentrated in Q1-Q3 2023, while gas consumption remained just below its 2022 levels in Q4. The power sector alone accounted for 75% of the demand reduction, as lower electricity demand together with the continued expansion of renewables and improving nuclear availability weighed on gas-fired power generation.

Distribution network-related demand fell by an estimated 7% (or over 10 bcm) in 2023, with the decline almost entirely concentrated in Q1. Preliminary data suggest that distribution network-related demand remained close to its 2022 levels in Q4. Our analysis indicates that non-weather-related factors contributed to the majority the demand reduction in the residential and commercial sectors in 2023 They include efficiency gains, administrated gas-saving measures, fuel switching, deployment of heat pumps, behavioural changes and rising affordability issues. Consequently, the heating intensity (gas use per heating degree day) further declined in 2023, potentially indicating that the non-weather-related factors weighing on residential and commercial gas demand may persist beyond 2022.

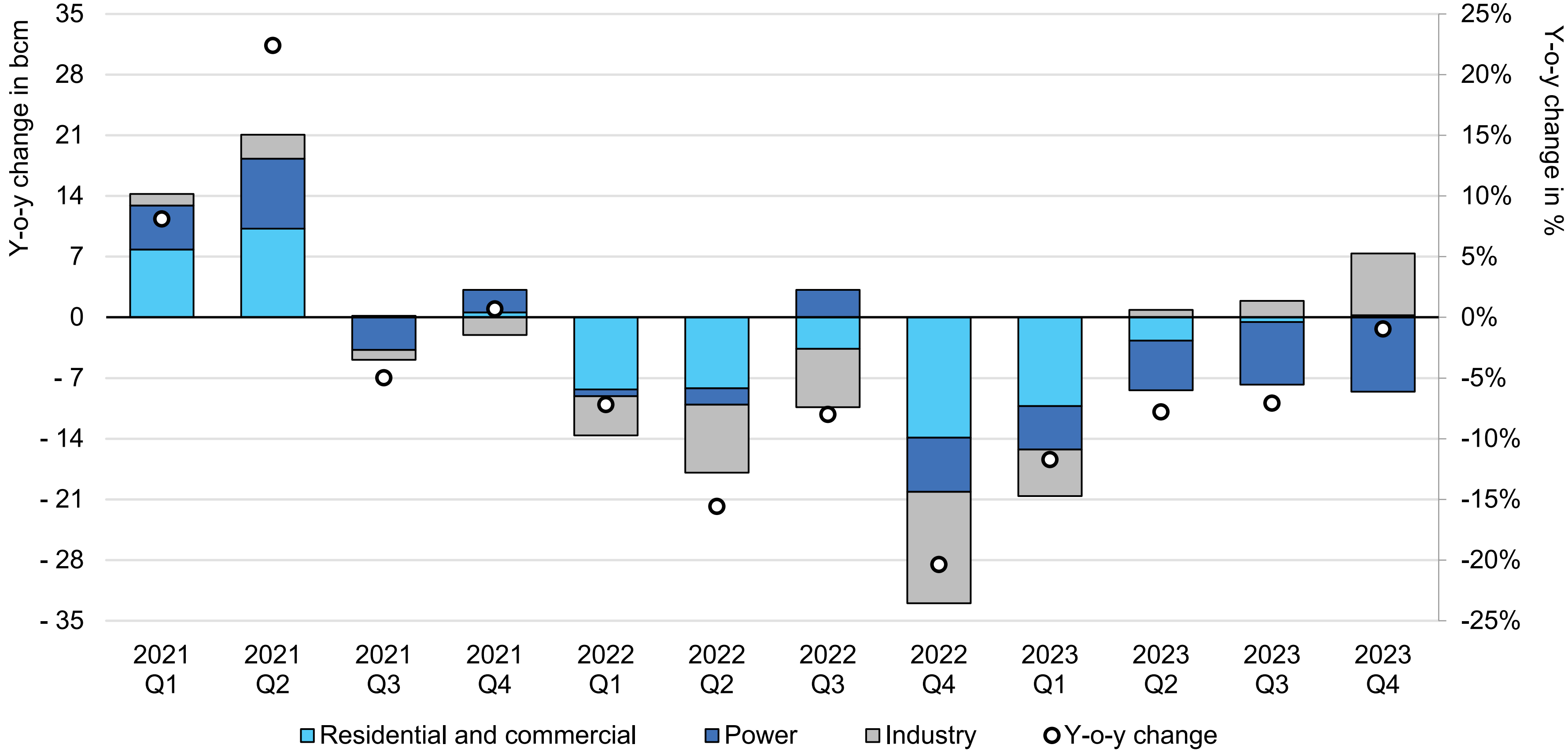
Gas-to-power demand declined by over 15% (or more than 25 bcm) in 2023. This steep reduction was driven by a combination of factors. Electricity consumption declined by an estimated 3% (or 90 TWh) in 2023, amid subdued activity in energy-intensive industries, energy efficiency gains and behavioural changes. Stronger renewable power output (up by 8%) and improving nuclear availability in France (up by 15%) further reduced the call on gas-fired power plants.

Natural gas consumption in **industry** increased marginally in 2023, as the declines recorded in the first half of the year (down 6% y-o-y) were more than offset by the increase in H2 2023. The continued decline in natural gas prices supported a moderate recovery in industrial sector gas demand, which rose by over 10% y-o-y in H2 2023, albeit remaining almost 15% below its H2 2021 levels. Preliminary data indicate that industrial sector gas consumption in H2 2023 rose by 15% y-o-y in Belgium, 4% in Italy, 10% in the Netherlands and by over 15% in Spain.

Our **forecast** expects natural gas demand in OECD Europe to increase by a moderate 3% in 2024, as the decline in gas-to-power demand is offset by higher gas use in the residential, commercial and industrial sectors. Gas burn in the power sector is forecast to drop by close to 10% amid the rapid expansion of renewables and improving nuclear availability in France. An assumed return to average weather conditions is expected to increase gas demand in the residential and commercial sectors. Gas use in industry is forecast to continue its recovery, although fragile and largely dependent on the evolution of prices.

…as lower gas burn in the power sector continued to weigh on demand

Estimated quarterly change in gas demand, OECD Europe, 2021-2023



Sources: IEA analysis based on Enagas (2023), Natural Gas Demand; ENTSOG (2023), Transparency Platform; EPIAS (2023), Transparency Platform; Trading Hub Europe (2023), Aggregated consumption.

US natural gas production rose to a record high in 2023

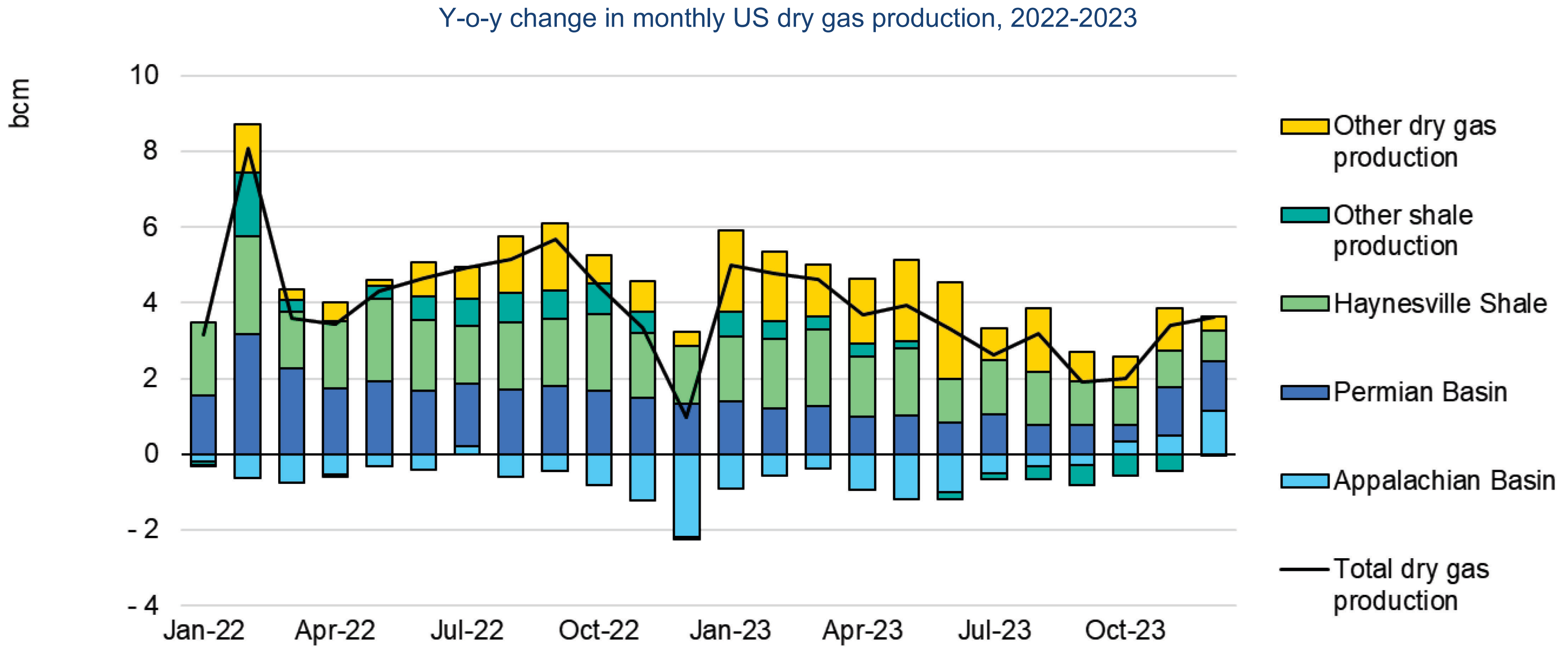
US dry natural gas production continued on its established growth path in 2023. From already record levels in 2022, production increased by a further 4 Bcf/day (4%) to reach an annual average of around 103 Bcf/d. However, production growth showed signs of easing throughout the year as monthly year-on-year growth slowed from February onwards.

Keeping in line with multi-year trends, the Permian and Haynesville Basins were again the main growth drivers in 2023, accounting for around three-quarters of the incremental production volumes brought to market in the year. A year-on-year increase of more than 40% in the average **Haynesville** rig count in 2022 – encouraged in part by a spike in domestic natural gas spot prices in that year – helped drive an estimate 12% production growth in 2023. In the **Permian Basin** – where gas output is mostly associated production – supply grew by approximately 8% over the same period, aided by high oil prices and a sustained oil rig count throughout 2022. Combined, these two basins added more than 10 Tcf of incremental production in 2023.

The **Appalachian Basin**'s gas production plateau extended into 2023, even registering a slight decline for the second year in a row. While it remains the largest single source of US natural gas output, growth has tailed off since early 2019 onward as production volumes have met takeaway capacity constraints. Building interstate pipelines – necessary to transport additional Appalachian production to demand areas – has proven increasingly difficult in recent years, as growing legal challenges against projects have raised costs and delayed project timelines. Furthermore, lower seasonal demand in the autumn months kept regional prices low, scaling back production incentives. As a result, Appalachian natural gas production is estimated to have fallen by about 1% in 2023.

US gas production is set to continue growing in 2024, albeit at a slower rate than in 2023 as clement weather, above-average storage levels and liquefaction project delays temper the positive effects of takeaway pipeline developments in key production basins. Commercial start of the **Mountain Valley Pipeline** (MVP), delayed from late 2023 to the first quarter of 2024, should add 20 bcm of takeaway capacity from the Appalachian Basin to demand centres further south. However, transmission constraints further downstream could slow the ramp-up in MVP utilisation, weakening the debottlenecking effect on Appalachian production. We expect **Permian and Haynesville** production to continue to lead growth, aided notably by the completion of two Permian pipeline expansion projects in September and December 2023 (Whistler Pipeline and Permian Highway Pipeline expansions, respectively). However, the delay in bringing online the first train of the Golden Pass liquefaction project from 2024 to 2025 is set to soften production growth in southern basins close to the coast. Overall, US dry gas production growth is set to slow to below 2% in 2024.

The Permian and Haynesville continue to drive US gas production growth



Note: November and December 2023 include estimated data.

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

Europe's pull on LNG softened in H2 2023 amid lower gas demand and high inventories

OECD Europe's primary natural gas supply declined by 12% (or 60 bcm) in 2023, amid the region's continued decline in gas demand and lower storage injection needs. The share of LNG in the total primary gas supply rose to a record high of 37% in 2023, while the share of Russian piped gas continued to shrink, dropping to around 10%.

Following a surge of 60% in 2022, **Europe's LNG imports declined marginally in 2023**, as lower gas demand and high storage levels eased the pull on LNG imports. Europe's LNG imports grew by a strong 8% (or 6.5 bcm) y-o-y in H1 2023, before recordin g a drop of 10% (or 9 bcm) y-o-y in H2. Subdued demand together with high inventory levels pushed European hub prices below Asian spot LNG prices during H2 2023: Platts JKM had an average premium of USD 2/MBtu over TTF, which encouraged flexible LNG cargoes to favour Asian markets instead of Europe. Despite lower LNG inflows, **the share of LNG in Europe's primary gas supply rose** from 33% in 2022 **to a new high of 37% in 2023** – a share comparable to Russia's piped gas before its invasion of Ukraine. LNG inflows from the United States rose by 7.5% (or 5.5 bcm). This further reinforced the position of **the United States as Europe's largest LNG supplier**, with its share of total LNG imports rising from 43% in 2022 to 47% in 2023. Hence, US LNG accounted for more than 15% of Europe's natural gas demand in 2023.

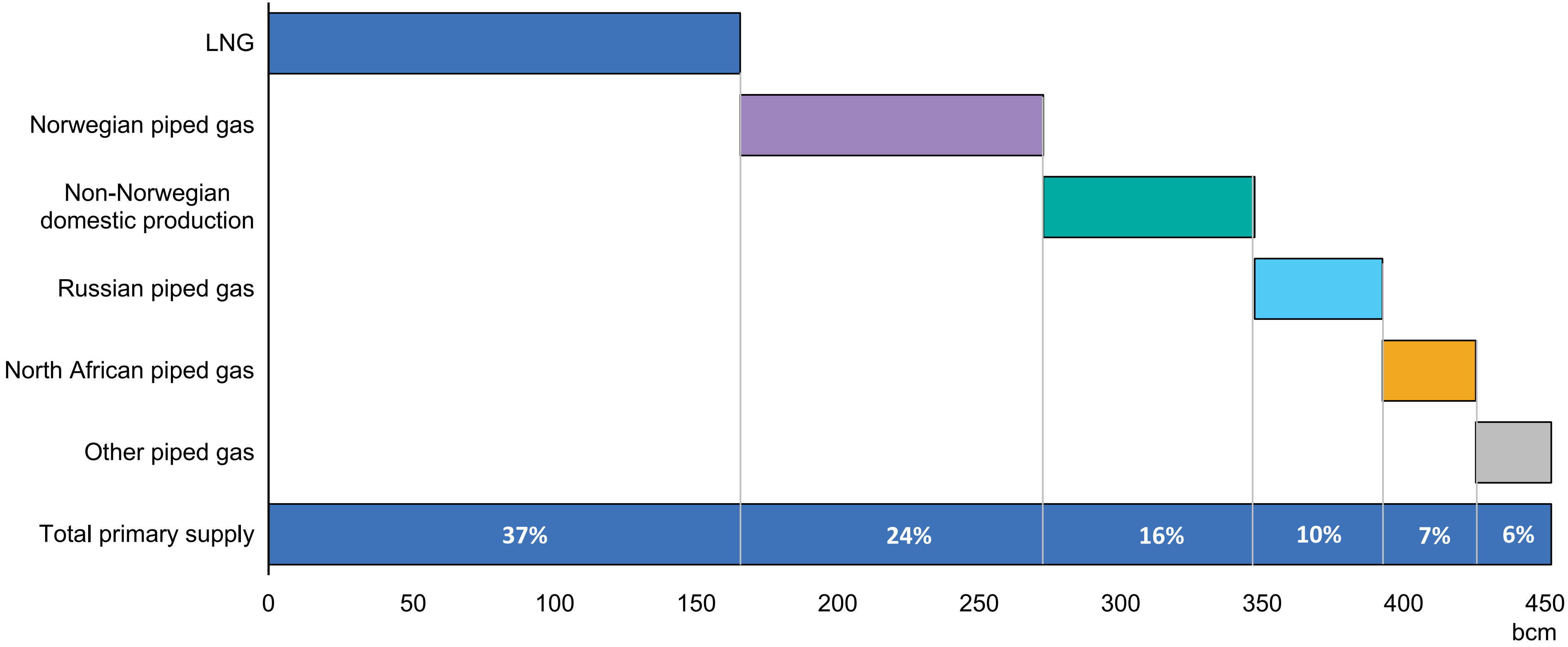
Norway's piped gas deliveries to the rest of Europe declined by 7% (or 8.5 bcm) 2023 amid a higher level of planned maintenance and unplanned outages. Norwegian pipeline supplies to the European Union fell by 4%, while exports to the United Kingdom dropped by 17%. **Non-Norwegian domestic production** fell by an estimated 12% (or 9.5 bcm) y-o-y in the first eleven months of 2023. **The Netherlands** alone accounted for around 60% of the overall decline. The country's natural gas output dropped by 35% in 2023, amid **the closure of the Groningen field** and the continued production declines from small fields.

Russia's piped gas supplies to Europe almost halved in 2023, totalling at an estimated 45 bcm – their **lowest level since the early 1970s**. Deliveries to the European Union fell by more than 60% (or 38 bcm). Exports to Türkiye stayed close to their 2022 levels in the first eleven months of 2023. Pipeline gas deliveries from **North Africa** dropped by 2% (or 0.5 bcm), amid lower supplies to Iberia. Gas flows from **Azerbaijan** via the Trans Adriatic pipeline stayed near their 2022 levels in 2023.

Our **forecast** assumes that Russian piped gas supplies to OECD Europe remain close to their 2023 levels in 2024, albeit their profile remains a major uncertainty. LNG imports are expected to increase marginally in 2024 amid higher natural gas demand and a continued reduction in non-Norwegian domestic production.

LNG accounted for a record 37% of Europe's primary gas supply in 2023

OECD Europe's primary natural gas supply by source, 2023



Sources: IEA analysis based on ENTSOG (2023), Transparency Platform; Eurostat (2023), Energy Statistics; Gas Transmission System Operator of Ukraine (2023), Transparency Platform; ICIS LNG Edge; JODI (2023), Gas World Database.

LNG supply growth remained well below its historic average in 2023, with uncertainty clouding the 2024 outlook

Global LNG trade expanded by 2% y-o-y (or 12 bcm) in 2023. This is the lowest growth rate since 2014, barring the exceptional contraction in 2020. Growth was driven primarily by the United States on the supply side, which accounted for 87% of incremental global LNG volumes. The Asia Pacific region led LNG demand growth, accounting for virtually all incremental imports.

From a supply perspective, the top three LNG exporters, well-established since 2019, remained the same. In 2023 the **United States** moved to take first place for the very first time, exporting 116 bcm, surpassing both Australia and Qatar, tied at 106 bcm. Together, these three exporters accounted for more than 60% of global LNG supply.

Supply growth in 2023 was primarily driven by the United States and Africa. The United States recorded a remarkable 10% (10 bcm) y-o-y increase in LNG exports, despite no major new liquefaction plant starting operations in 2023. Growth was driven by the restart of Freeport LNG and the continued commissioning of Calcasieu Pass. In Africa, **Algerian LNG exports** saw a y-o-y increase of 26%, or nearly 4 bcm, targeting the European Union and Türkiye, and **Mozambique** added 3.6 bcm of supply as Coral South FLNG ramped up exports after starting its commercial operations in late 2022. In Europe, **Norway** increased its LNG production by 2 bcm y-o-y thanks to steady LNG production since the restart of the Hammerfest LNG plant in June 2022.

However, these increases were partially offset by declines in other countries. **Egypt**'s exports more than halved, falling by 5 bcm y-o-y due to a decline in domestic gas production, a sudden drop in piped gas imports from Israel in the fourth quarter and rising domestic demand. **Nigeria**'s exports were down by 8%, or nearly 2 bcm y-o-y, due to ongoing security and feedgas supply issues. For the first time ever (except in 2020), **Russian** LNG exports decreased, falling by 5% or 2 bcm y-o-y, mainly due to extended summer maintenance at the Sakhalin-2 plant and, to a lesser extent, at Yamal LNG. **Qatari** exports fell by 1%, or 1 bcm y-o-y.

From a demand perspective, China regained its position as the world's largest LNG importer in 2023, ahead of Japan and Korea. The **Asia Pacific** region returned to growth in 2023, with overall LNG imports increasing by 4% (or 14 bcm) y-o-y. This was primarily driven by **China** (up by 14% or 11.5 bcm), **Thailand** (up by 40% or 4 bcm) and **India** (up by 11% or 3 bcm). The expansion of economic activity, together with stronger gas burn in the power sector, supported higher LNG imports in these countries. In contrast, LNG imports declined sharply in the mature markets of Asia, principally **Japan** (down by 8% or 7.5 bcm) and **Korea** (down by 3% or 2 bcm) y-o-y, as improving nuclear availability and lower electricity demand weighed on gas-fired power generation. Thanks to the significant drop in Platts JKM prices from the beginning of 2023, South Asian buyers returned to the spot markets via tenders, notably in a context of high electricity demand as a result of heatwaves affecting the region in spring and summer 2023. **Bangladesh** and **Pakistan** saw their LNG imports increase by 20% and 5% respectively, translating into a combined increase in LNG imports of 1.6 bcm compared to 2022.

European LNG import growth was muted in 2023, falling by 1.5% or 2.5 bcm amid persistently low demand and reduced storage injection needs compared to 2022. Trends differed markedly by month and by country. LNG inflows grew by 8% y-o-y in the first half of the year, which was more than offset by a 10% y-o-y decline in the second half. Likewise, while **the Netherlands**, **Germany**, **Italy** and **Finland** increased their LNG imports by more than 15 bcm compared to 2022, this was mostly offset by decreases recorded in **France**, **the United Kingdom** and **Spain**.

LNG imports into **Central and South America** increased by 10% (or 1.5 bcm) y-o-y in 2023 despite **Brazil**'s LNG imports dropping by 61% (or 1.8 bcm) y-o-y, as healthy hydro availability weighed on gas burn in the power sector.

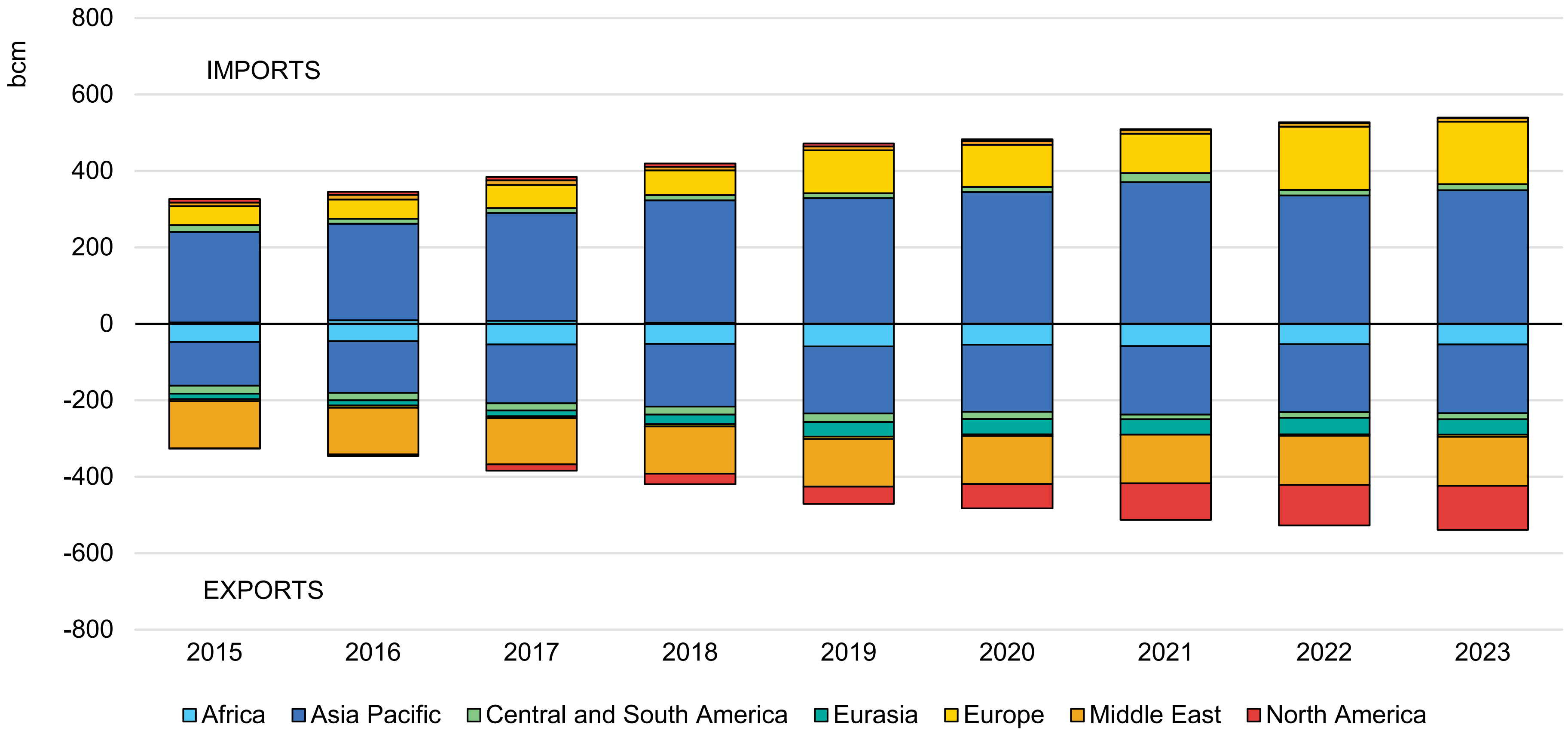
For **2024** we forecast global LNG trade to increase by around 3.5% (or 18 bcm). Africa is expected to account for almost a third of **additional LNG supply**. This is supported by the planned start-up of Greater Tortue Ahmeyim FLNG (off the coast of Mauritania and Senegal) in Q1 2024 and higher production from legacy liquefaction plants. Around a quarter of incremental LNG supply is expected to come from the United States and Mexico, less than in our previous forecasts following the announced postponement of Golden Pass Train 1 to 2025.

Demand growth is set to be largely driven by Asia. China's LNG imports are expected to increase by more than 10% from 2023 levels, growing by a similar amount to last year. We expect **India** to increase its LNG imports in 2024 by 7%, fuelled by demand from the power and fertiliser sectors, as the country plans to stop importing urea by 2025. **Bangladesh** and **Pakistan** are expected to import more LNG in 2024 due to the combination of rapidly declining domestic gas production and the commissioning of new gas-fired power plants. Europe's LNG imports are expected to grow year-on-year, slightly surpassing the 2022 high.

It is important to highlight **the high level of uncertainty** that clouds estimates for both LNG production and consumption levels, and also the potential impacts of the Panama and Suez Canal transit issues. Potential start-up delays at new liquefaction plants, a tense geopolitical context and worsening feedgas issues at certain legacy projects all represent downward risks to the present outlook. Simultaneously, adverse weather conditions (including a colder-than-average winter and lower hydro availability) could contribute to tighter market conditions and price volatility.

LNG demand growth was largely driven by the Asia Pacific region in 2023

LNG imports and exports by region, 2015-2023



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

Panama Canal congestion to slow US–Asia LNG trade, while LNG ships face security risks in the Middle East

Due to a severe drought, the Panama Canal Authority (PCA) introduced draught restrictions several times in 2023 for vessels – such as LNG carriers – using the Neopanamax locks. These measures are part of water conservation efforts that began in early January. The Gatun Lake reservoir, which supplies water to the canal, has been experiencing a rapid decline in its water level and reached a record low last summer. Drought is set to be exacerbated by the El Niño weather pattern until at least spring 2024.

While these restrictions do not directly affect LNG trade, they may lead to increased traffic congestion and potential delays. Under normal conditions, the expected waiting time for LNG tankers transiting through the Panama Canal is two to three days. However, waiting times increased in 2023, rising to an average of 15 days as of mid-December for unreserved slots. LNG tankers can receive a slot to transit the Panama Canal through the Transit Reservation Booking System, either by booking in advance or by participating in an auction for available slots. The transit fee for an LNG carrier with a cargo capacity of 170 000 m^3 was estimated at USD 0.6-0.7 million for bookings made in advance.

The PCA has set up an auction system that allows shippers to apply for priority passage. This system allocates scarce capacity in a market-based way, which brings certain risks for shippers, including:

- **Increased costs**: This auction system considerably increases the cost of transporting LNG through the canal. In total, for all commodities combined, shippers paid more than USD 235 million in auction fees from January to mid-November 2023 to bypass the Panama Canal's congestion, a 20% increase y-o-y. These fees are paid in addition to the usual tolls, with a record amount for a single ship of close to USD 4 million paid in November 2023.
- **Unpredictability**: The auction system introduces a level of unpredictability into the shipping process. The fees for expedited passage are set by market dynamics and can vary significantly.

In principle, alternative routes, while longer, provide certainty in scheduling and avoid delays due to congestion on the Panama Canal. For instance, from the US Gulf of Mexico, the journey to Japan via the Suez Canal takes a little over a month, and Africa's Cape of Good Hope route is about 40 days, compared to just over 20 days via the Panama Canal.

In 2023 the number of US LNG cargoes passing through the Panama Canal declined sharply, particularly in Q2 (down 16% y-o-y), in favour of alternative routes via the Suez Canal or the Cape of Good Hope. Persistent congestion and diversions could lead to longer journeys, a shortage of available vessels and, consequently, higher shipping rates.

In October 2023, to encourage shippers to use its route rather than the Panama Canal, the Suez Canal Authority (SCA) implemented a staggered discount system for LNG tankers sailing from the US Gulf of Mexico to ports east of Egypt, with reductions on canal tolls ranging from 30% for destinations west of Kochi in India, to 70% for Singapore and beyond. However, Suez Canal transit fees for LNG carriers will be subject to a 15% increase in 2024.

The escalation of regional conflict, which began with the war between Israel and Hamas in October 2023, could significantly affect LNG flows in the Middle East. Qatar, which alone accounted for 20% of global LNG supplies in 2023, and the United Arab Emirates primarily transport their LNG production through the Strait of Hormuz. Consequently, any disruption to this route could have major implications for global LNG markets.

Furthermore, due to the rising number of attacks in the Bab al-Mandab Strait between Yemen and Djibouti, an increasing number of LNG ships are altering their Middle East transit routes. These attacks have heightened maritime security risks and driven up regional insurance costs.

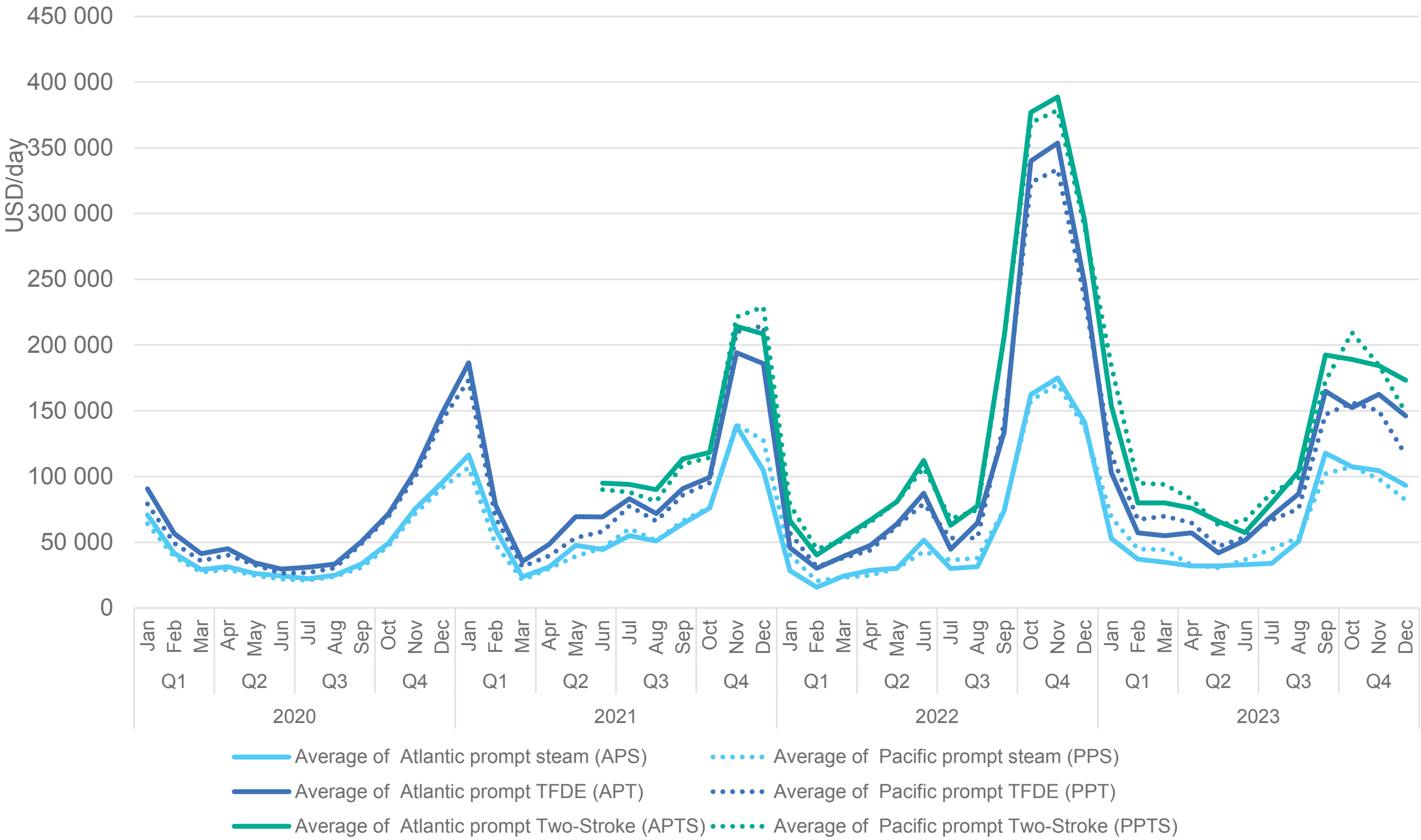
Shipping data indicate that eastbound flows via the Suez Canal accounted for 4% (or 21 bcm) of global LNG trade in 2023. US deliveries to markets in Asia and the Middle East accounted for more than half of the total eastward transit flows via the Suez Canal. Markets in Asia can be reached via the Panama Canal or via the Cape of Good Hope. The duration of US LNG shipments to western India would increase by around five days if delivered via the Cape of Good Hope versus the Suez Canal. Stopping transit through the Suez Canal would increase shipping distances and add upward pressure to spot LNG charter rates.

In 2023, nearly 4% of global LNG trade (or 20 bcm) flowed westward through the Suez Canal. Over 90% of this was delivered from Qatar to Europe. All LNG deliveries from Qatar to Europe transited via the Suez Canal as this is the shortest trading route. Following Qatar Energy’s decision to halt sending its LNG ships through the Red Sea in January 2024, Qatari LNG supplies have been reaching Europe via the Cape of Good Hope, doubling shipping time compared with transit through the Suez Canal. This could also put upward pressure on spot LNG charter rates and ultimately translate into higher LNG supply costs.

Spot LNG charter rates in Q4 2023 were at their lowest since 2020, with Atlantic freight rates for tri-fuel diesel electric (TFDE) and two-stroke propulsion down by 50% y-o-y. The tightening of intra-basin price spreads, together with the commissioning of new LNG carriers, weighed on spot LNG charter rates in 2023. However, the LNG shipping market could tighten as winter progresses in the northern hemisphere, particularly in the event of cold spells, as LNG vessel utilisation is expected to increase, with ships taking longer routes to deliver cargoes to Asia.

Despite congestion in the Panama Canal and security risks in the Middle East, LNG spot freight rates for Q4 2023 remain at a three-year low

Atlantic and Pacific spot LNG freight rates, 2020-2023



Note: This graph shows freight prices for steam vessels (older ships), TFDE (more modern tri-fuel diesel electric) and two-stroke (the most modern) vessels, for prompt deliveries (up to 90 days' charter with delivery within 40 days), for both the Atlantic and Pacific basins.

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

A softer winter market: Natural gas prices remained well below their 2021-22 highs in Q4 2023

Natural gas prices rose across all key markets in Q4 2023 compared to the previous quarter as the start of the Northern Hemisphere winter tightened supply–demand fundamentals. However, high storage levels and improving supply dynamics kept natural gas prices **well below the Q4 average in 2021 and 2022**.

In **Europe**, TTF spot prices rose by 20% on the quarter to an average of just below USD 13/MBtu in Q4 2023, amid higher seasonal gas demand. But continued year-on-year demand reductions together with high inventory levels and healthy LNG supply kept European hub prices 55% and 60% below the Q4 averages displayed in 2022 and 2021 respectively. While TTF prices fell significantly on the year, they remained almost 120% above their 2016-2020 Q4 averages. All-time high storage levels limited short-term price variability. Volatility on TTF month-ahead prices averaged 80% in Q4 2023 – around 25% below the volatility displayed during the same period of the previous year. TTF's premium over NBP narrowed to below USD 0.2/MBtu in Q4 2023 from almost USD 5/MBtu during the same period a year earlier. This in turn reduced the incentive for piped gas flows from the United Kingdom towards continental Europe, declining from 4.5 bcm in Q4 2022 to 1.5 bcm in Q4 2023.

In **Asia**, Platts JKM prices followed a similar trajectory and rose by over 20% on the quarter to an average of USD 15/MBtu in Q4 2023, albeit 50% lower than during the same period of the previous year.

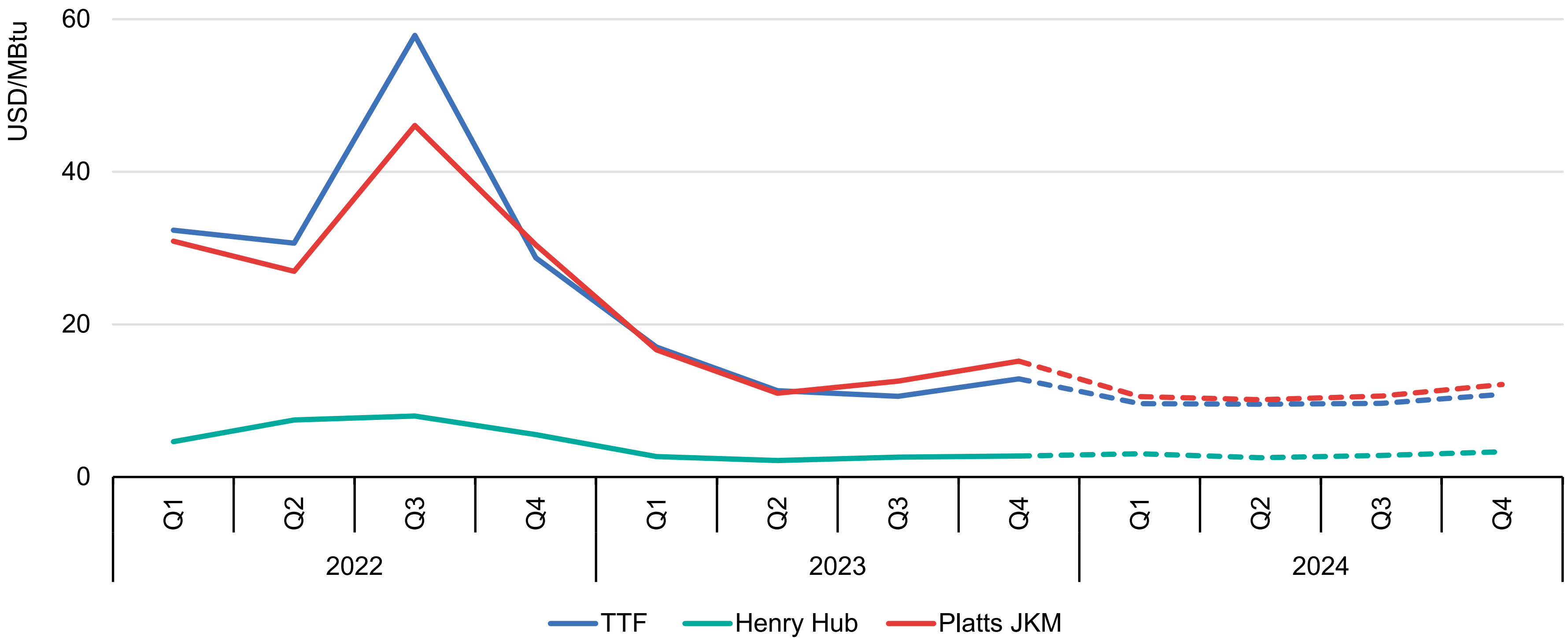
Lower competition with Europe for spot LNG cargoes, together with high storage levels across northeast Asian markets and higher nuclear availability in Japan, kept Platts JKM well below its average levels in Q4 2022. **Asian spot LNG prices recovered their premium over European hub prices** at the end of May 2023. Platts JKM averaged USD 2/MBtu above TTF month-ahead prices in H2 2023. The re-emergence of the JKM premium above TTF drove LNG cargoes away from Europe. While Asia's LNG imports grew by 7% y-o-y in H2, Europe's declined by 10%.

In the **United States**, Henry Hub prices increased by 5% on the quarter to average USD 2.7/MBtu in Q4 2023, their lowest Q4 levels since 2020. Continued growth in domestic natural gas production, together with lower space heating demand amid a mild Q4 and high inventory levels, pushed Henry Hub 50% below its average in Q4 2023.

According to **forward curves** as of mid-January 2024, TTF is expected to average 20% below its 2023 levels in 2024, at around USD 10/MBtu. Forward curves suggest that Asian spot LNG prices will retain their premium over European hub prices in 2024, with JKM averaging USD 1/MBtu above TTF. This should provide an incentive for higher LNG flows into the Asian markets. Based on forward curves, Henry Hub prices in the United States are set to increase by 15% amid tighter market fundamentals, with an average close to USD 3/MBtu.

Asian spot LNG prices are expected to retain their premium over TTF in 2024

Main spot and forward natural gas prices, 2020-2023



Note: Future prices are based on forward curves as of the end of September 2023 and do not represent a price forecast.
Sources: IEA analysis based on CME Group (2023), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements, LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2023), Henry Hub Natural Gas Spot Price; Powernext (2023), Spot Market Data; S&P Global (2023), Platts Connect.

Natural gas storage continued to temper security of supply risks in 2023

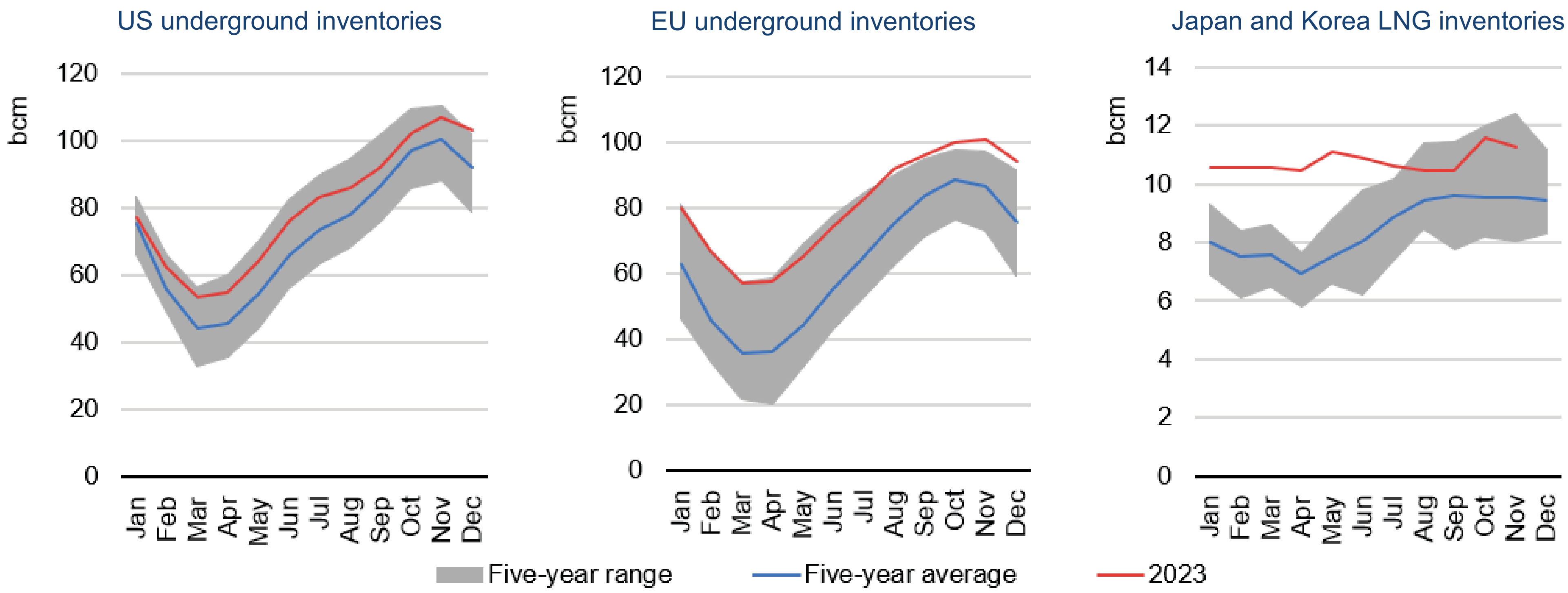
Levels of natural gas storage remained above average throughout 2023 and closed the year at or near the top of the five-year range in all three key regions. **High inventory levels** provide a safety buffer to demand centres, reducing supply risks from any unfavourable weather or potential supply disruptions during winter 2023/24.

In the **European Union** subdued winter demand, together with ample pipeline and LNG imports, kept storage withdrawals almost 40% below their five-year average during the 2022/23 heating season. Consequently, EU storage sites opened the 2023 gas summer 55% full, standing 65% (or 23 bcm) above their five-year average on 1 April. Storage injections fell 22% (or 12 bcm) below their five-year average in Q2-Q3 2023 amid lower primary gas supply. While slower injection rates moderated the EU storage surplus, inventory levels still stood 12% (or 10 bcm) above their five-year average on 1 October 2023. EU traders also injected 2 bcm of natural gas into Ukraine's gas storage facilities before the start of the 2023/24 winter season. Lower EU gas demand in the first part of the winter kept storage withdrawals 21% (or 4 bcm) below their five-year average. Consequently, EU storage sites closed 2023 86% full, with inventory levels standing 19% (or 15 bcm) above their five-year average. However, the risk of late-winter cold spells and unexpected supply constraints still looms in a relatively tight market. As such, end-of-winter fill levels in 2024 will be key in swaying market sentiment for the rest of the year.

In the **United States** storage levels also remained well above five-year average levels in 2023, contrasting with a below-average year in 2022 as a result of strong withdrawals in first quarter of that year. Relatively weak heating demand during Q1 2023 and healthy domestic production helped reduce storage draw, pushing end-of-winter storage levels towards the top of the recent historical range. Despite year-on-year demand growth in all subsequent months of 2023, ample supply helped drive strong injections, pushing the maximum fill level ahead of winter up to around 90% of working storage capacity, or 6 bcm above the five-year average. After starting later than usual in the heating season, storage withdrawals picked up in late November and December but remained below average. Storage levels ended the year at the top of the five-year range. US storage sites closed 2023 82% full, with inventory levels standing 13% (or 11 bcm) above their five-year average.

LNG storage levels in **Japan** and **Korea** entered 2023 at historical highs following a strong filling campaign in 2022. While stockpiles remained flat in Q1, lower LNG imports in the summer months pulled LNG stocks below 2022 levels (notably in Japan). However, combined LNG stocks in the two countries rose to 18% above the five-year average by end-November, thanks to stable volumes in Korea and strong stockbuild in Japan. Declared LNG stocks held by Japan's largest power utilities stood at 2.7 Mt (or 3.6 bcm) at the end of December 2023 – 30% above their five-year average.

Storage inventories remained above average across key markets throughout 2023



Sources: IEA analysis based on EIA (2023), Weekly Working Gas in Underground Storage; GIE (2023), AGSI+ Database; IEA (2023), Monthly Gas Data Service.

Spotlight on GHG emissions along gas value chains

Cutting GHG emissions along gas value chains is crucial to reach net zero

This section provides an overview of the **GHG emissions reduction initiatives** (policies and regulations) being undertaken by key gas and LNG producers and importers. It is a result of a **survey** carried out among the members of the **IEA Task Force on Gas and Clean Fuels Market Monitoring and Supply Security (TFFS)**. Notably the data from different countries often vary due to the diverse scopes and methodologies applied, highlighting an **urgent need for a consistent, universally accepted framework for reporting GHG emissions**, a framework that is currently under development.

GHG emissions from natural gas-related operations (production, processing and transport) totalled 1.7 Gt CO_2-eq in 2022, equating to **around 5% of global energy-related GHG emissions**. Methane emissions, both upstream and downstream, accounted for around two-thirds of the total GHG emissions stemming from gas and LNG supply chains. The **energy needs** of the various processes associated with the extraction and processing of natural gas accounted for over 15% of the total GHG emissions, while the share from **transport** (both via pipeline and in the form of LNG) was around 10%. **Vented CO_2** contributed approximately a further 8%. As highlighted by the IEA's [Oil and Gas Industry in Net Zero Transitions report](), the scope 1 and 2 emissions intensity of natural gas averages 10 t CO_2-eq/m^3. However, emissions intensity varies significantly, from less than 8 t CO_2-eq/m^3 for the best performers to 24t CO_2-eq/m^3 for the worst.

Reducing emissions will require effort across the entire value chain. Halving the emissions intensity of scope 1 and 2 oil and gas-related operations would require USD 600 billion of investment between 2022 and 2030. Upstream and downstream methane emissions could be reduced by around 75% via measures such as **leak detection, repair programmes and installing emissions control devices**. Around 40% of methane emissions from oil and gas operations could be avoided at zero net cost.

CCUS-based solutions can reduce carbon emissions associated with the production of natural gas by capturing and storing reservoir CO_2 during the processing of raw gas. The emissions intensity of natural gas transported via pipeline can be reduced through the mitigation of methane leaks and the electrification of compressor stations. In the case of LNG, the use of **electric drives** instead of gas turbines to power the liquefaction compressors can significantly improve the environmental performance of an LNG plant, provided that the electricity originates from low-emissions sources. In addition, CCUS-based solutions can be applied directly at the liquefaction plant level. Furthermore, the emissions intensity of **LNG shipping** can be improved via better fuel efficiency standards, enhanced boil-off management systems and the optimisation of shipping routes.

International co-operation is key to reducing GHG emissions along gas value chains

International co-operation, together with public–private partnerships, will be central to facilitating and fast-tracking the **reduction of GHG emissions** stemming from gas and LNG supply chains. This should include establishing commonly agreed measurement, monitoring, reporting and verification (MMRV) mechanisms, sharing best practices on technologies that effectively reduce emission intensities and channelling financial flows towards projects that enable GHG emission reductions.

In November 2021 the **Global Methane Pledge** (GMP) was launched at the 26th UN Climate Change Conference of the Parties (COP26). Over 150 countries, representing a little over 50% of global methane emissions, have joined the GMP, thereby committing to a collective goal of reducing global anthropogenic methane emissions by at least 30% compared to their 2020 levels by 2030. It is estimated that delivering the GMP would have a similar impact on global warming as switching the entire global transport sector to net zero emission technologies.

The **International Methane Emissions Observatory** (IMEO) was launched at the G20 Leaders' Summit in 2021, with a focus on emissions from the fossil fuel industry. IMEO relies on data from the satellite-based **Methane Alert and Response System** (MARS), from industry reporting through the **Oil and Gas Methane Partnership 2.0** (OGMP 2.0), and from national inventories.

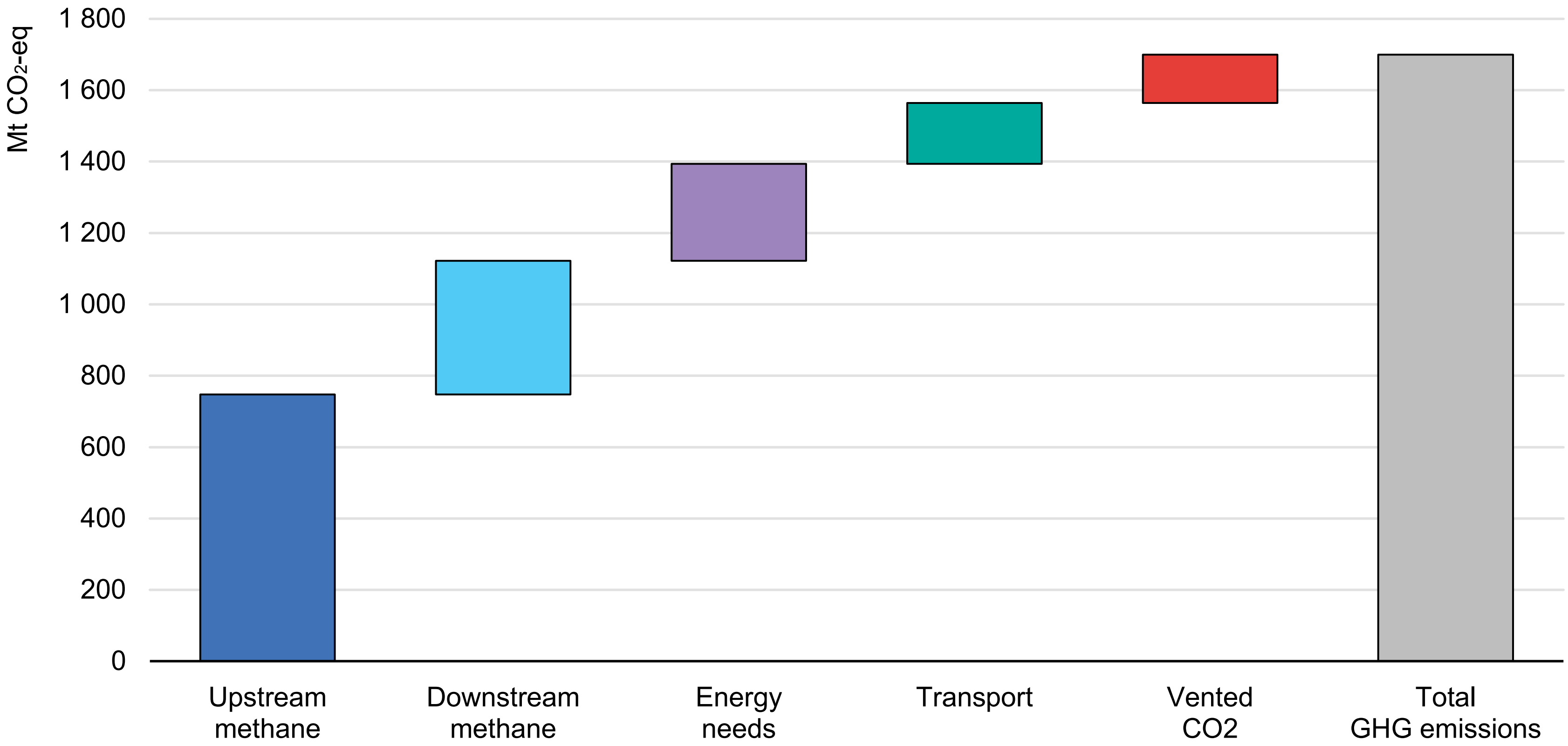
Companies participating in OGMP 2.0 account for over 37% of the world's oil and gas production and more than 70% of LNG flows.

Methane emissions were in the spotlight at COP28 held in December 2023. The **Oil and Gas Decarbonisation Charter** (OGDC) was signed by 50 oil and gas companies (with national oil companies accounting for over 60% of signatories) who pledge to align with net zero by 2050, zero-out methane emissions and eliminate routine flaring by 2030. The World Bank launched the **Global Flaring and Methane Reduction Partnership** at COP28, backed by USD 255 million. The trust fund will be focused on helping developing countries cut CO_2 and methane emissions generated by the oil and gas industry. The **GMP** was joined by six new countries, including Turkmenistan, which has one of the highest GHG emission intensities among gas suppliers.

The IEA provides country-level information on sources of methane emissions through its Global Methane Tracker, with a detailed view of abatement options and policy solutions for the oil and gas sector. The reduction of GHG emissions from gas value chains is part of the work programme of the IEA's TFFS, which provides a platform for data and information exchange among its members and facilitates the sharing of best practices related to GHG emissions reductions.

Upstream and downstream[4] methane emissions account for two-thirds of total GHG emissions along gas and LNG value chains

Breakdown of global GHG emissions from natural gas supply, 2022



Note: One tonne of methane is taken to be equivalent to 30 tonnes of CO_2 based on a 100-year global warming potential.
Source: IEA (2023), The Oil and Gas Industry in Net Zero Transitions.

[4] Upstream refers to exploration and production of natural gas, midstream is the transportation and storage of natural gas, and downstream refers to the conversion of natural gas into finished products.

The United States deployed new policy measures to reduce GHG emissions

The United States became the world's largest LNG exporter in 2023, just seven years after the first cargo left the Sabine Pass LNG terminal in Louisiana. US LNG exports totalled 118 bcm in 2023 and are expected to expand by close to 50% by 2026. As reported by the US **Environmental Protection Agency** (EPA), GHG emissions at LNG plant level rose more than tenfold from just 1.4 Mt CO_2-eq in 2016 to 16.1 Mt CO_2-eq in 2022, implying a plant-level emission intensity of around 0.1 t CO_2-eq/t LNG in 2022. The United States has implemented several policies and regulations to control and reduce GHG emissions from its gas supply chains:

- Through the **Inflation Reduction Act** (IRA) and **Bipartisan Infrastructure Law** (BIL) the EPA is providing up to USD 1.55 billion in financial and technical assistance to reduce methane emissions in the oil and gas sector. BIL provides nearly USD 5 billion to plug tens of thousands of orphaned oil and gas wells, which are significant methane emitters.

- In December 2023 the EPA issued a **final rule to reduce methane emissions** and other harmful air pollution from oil and natural gas operations. It includes **New Source Performance Standards** to reduce methane and smog-forming volatile organic compounds from new, modified and reconstructed sources, and **emissions guidelines** that set procedures for states to follow as they develop plans to limit methane from existing sources.

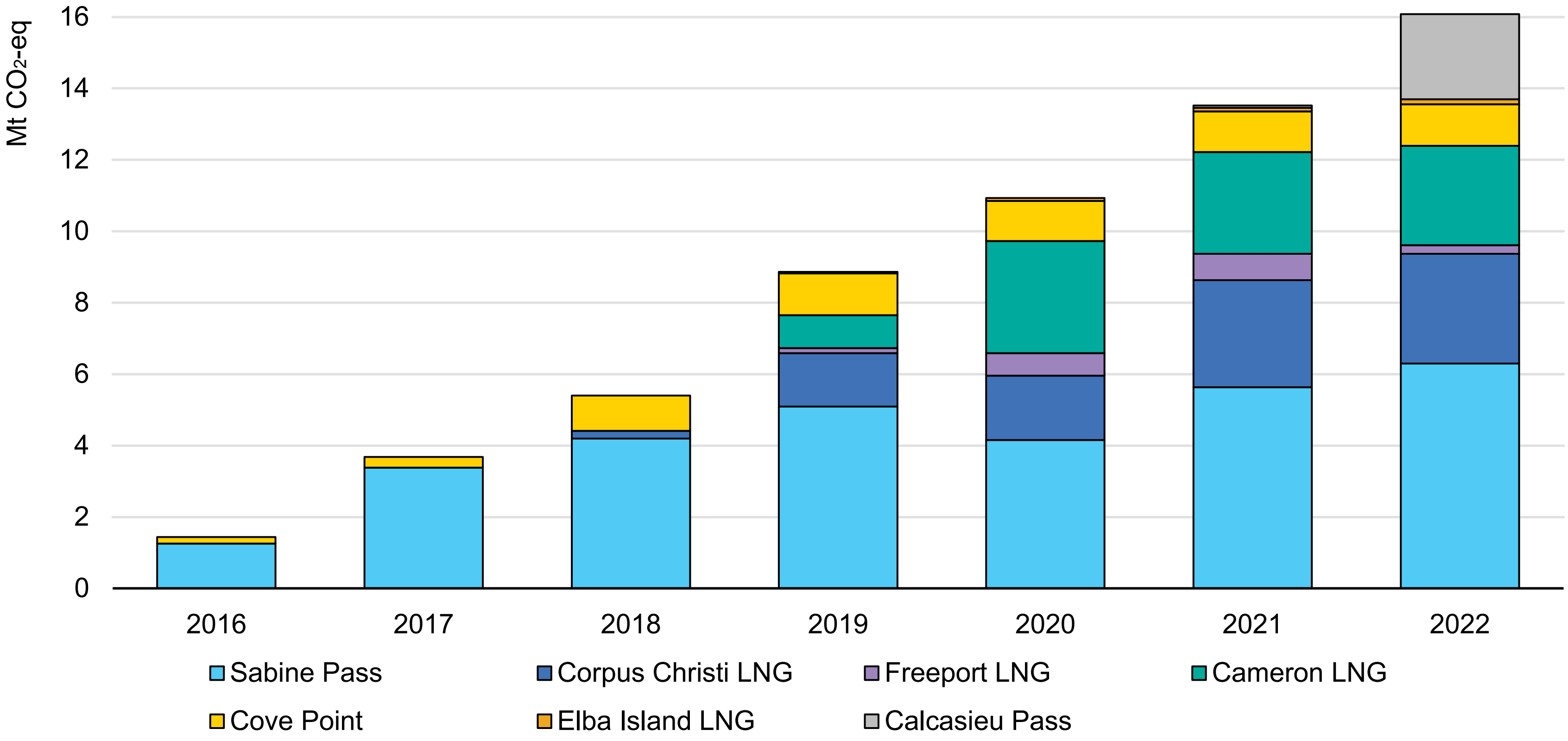
- In addition, the final rule includes a **Super Emitter Program** that will utilise third-party expertise in remote sensing to detect large methane releases or leaks known as "super emitters", which recent studies have indicated account for **almost half of methane emissions** from the oil and gas sector.

The US government leads and/or participates in numerous **international initiatives** aimed at reducing GHG emissions along gas supply chains. The United States provides technical assistance for methane measurement and mitigation through the EPA Global Methane Initiative, the Climate and Clean Air Coalition, the UN Environment Programme's International Methane Emissions Observatory, the World Bank Global Gas Flaring Reduction Partnership and the Commercial Law Development Program. In April 2023 President Biden launched the **Methane Finance Sprint**, aiming to raise at least USD 200 million of funding by COP28. This funding target should now be exceeded thanks to contributions from the United States and other countries.

While there is no federal definition or standard for **"responsibly sourced" natural gas** (RSG) in the United States, there are several initiatives at state level and within the industry to promote its production, use and certification. Industry surveys show that almost 30% of US gas production in 2022 was certified for its performance against certain environmental, social and governance metrics.

GHG emissions from US LNG production have risen more than tenfold since 2016

GHG emissions from US LNG production at LNG plant level, 2016-2022



Note: Data as reported by the US EPA.
Source: IEA analysis based on US Environmental Protection Agency (2023), Facility Level Information on GreenHouse gases Tool (FLIGHT).

Australia is tightening GHG emissions regulations to meet its 2050 net zero target

Australia's LNG production has grown strongly over the past decade, from just above 30 bcm in 2012 to 108 bcm in 2023, making it the world's third-largest LNG exporter behind the United States and Qatar. GHG emissions from LNG production have increased by almost 50% since the financial year (FY) 2016/17 to reach 36 Mt CO_2-eq. in FY 2021/22.[5] Given Australia's LNG production of about 83 mtpa (or 113 bcm) in FY 2021-22, the estimated emission intensity at the facility level is approximately 0.4 t CO_2-eq/t LNG. Australia has taken regulatory steps to enhance data transparency and reduce emissions from its gas production and LNG export plants.

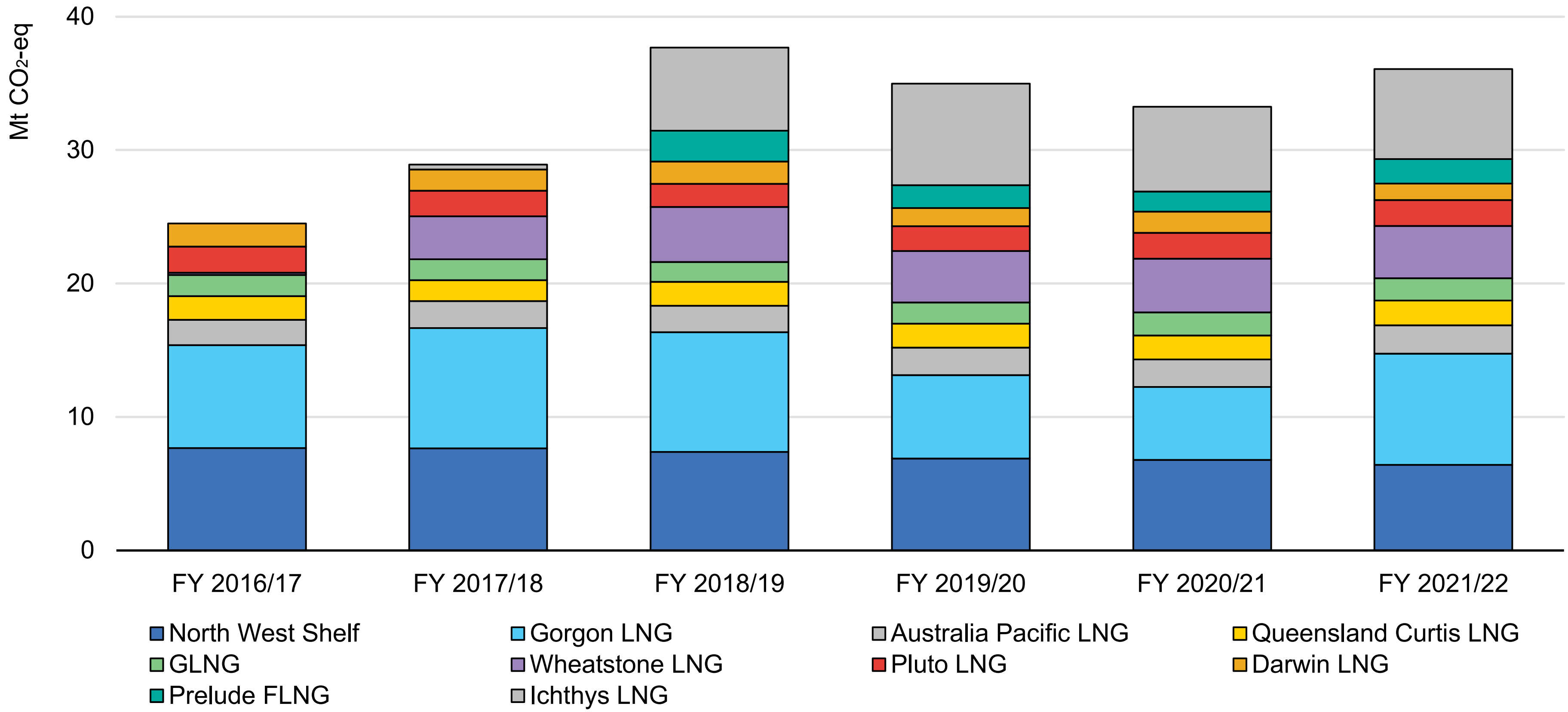
The **National Greenhouse and Energy Reporting** (NGER) scheme is a legislative framework that has been in operation for over a decade in Australia. It requires companies to report GHG emissions, and energy production and consumption annually. The NGER scheme data cover approximately 60% of GHG emissions in the national inventory, and 80% of energy consumption. This includes all Intergovernmental Panel on Climate Change combustion and fugitive emission sources from gas supply chains within Australia's territorial boundary, and the scheme is compliant with reporting obligations under the United Nations Framework Convention on Climate Change (UNFCCC) and the Paris Agreement. Key features of the NGER scheme include: (1) legislated thresholds for companies to report emissions and energy data; (2) a framework for measurement, reporting and verification of emissions and energy data; (3) a requirement for the release of enterprise-level emissions and energy data for public access.

The **Safeguard Mechanism**, established in 2016 and reformed in 2023, is a policy that aims to gradually reduce the GHG emissions of Australia's largest emitters (scope 1 emissions over 100 000 t CO_2-eq) and help the country meet its international climate commitments. It requires these facilities to keep their net emissions below an emissions limit (called baseline) set by the Clean Energy Regulator. Baselines are adjusted according to production levels so that they increase or decrease in line with production fluctuations and do not limit production. Facilities unable to reduce their emissions intensity can use other compliance options, including purchasing and surrendering **Australian Carbon Credit Units** (ACCUs) or new **Safeguard Mechanism Credits** (SMCs), which incentivise facilities to reduce emissions beyond their baselines. Under the Safeguard Mechanism reforms, new gas fields supplying existing LNG facilities must abate reservoir CO_2 emissions using CCS or offset them with ACCUs or SMCs.

[5] Based on data from the Australian Clean Energy Regulator (CER). CER is an independent authority, enforces laws to curb GHG emissions and boost clean energy, manages various government-legislated schemes for GHG emission control, and offers data and insights on Australia's carbon markets.

Australia's GHG emissions from LNG production have grown by almost 50% since FY 2016/17

Australia's GHG emissions by LNG production facilities, FY 2016/17-FY 2021/22



Note: Data as reported under the Safeguard Mechanism.
Source: IEA analysis based on Clean Energy Regulator (2023), Safeguard data.

Norway aims to reduce its GHG emissions from the oil and gas production to net-zero by 2050

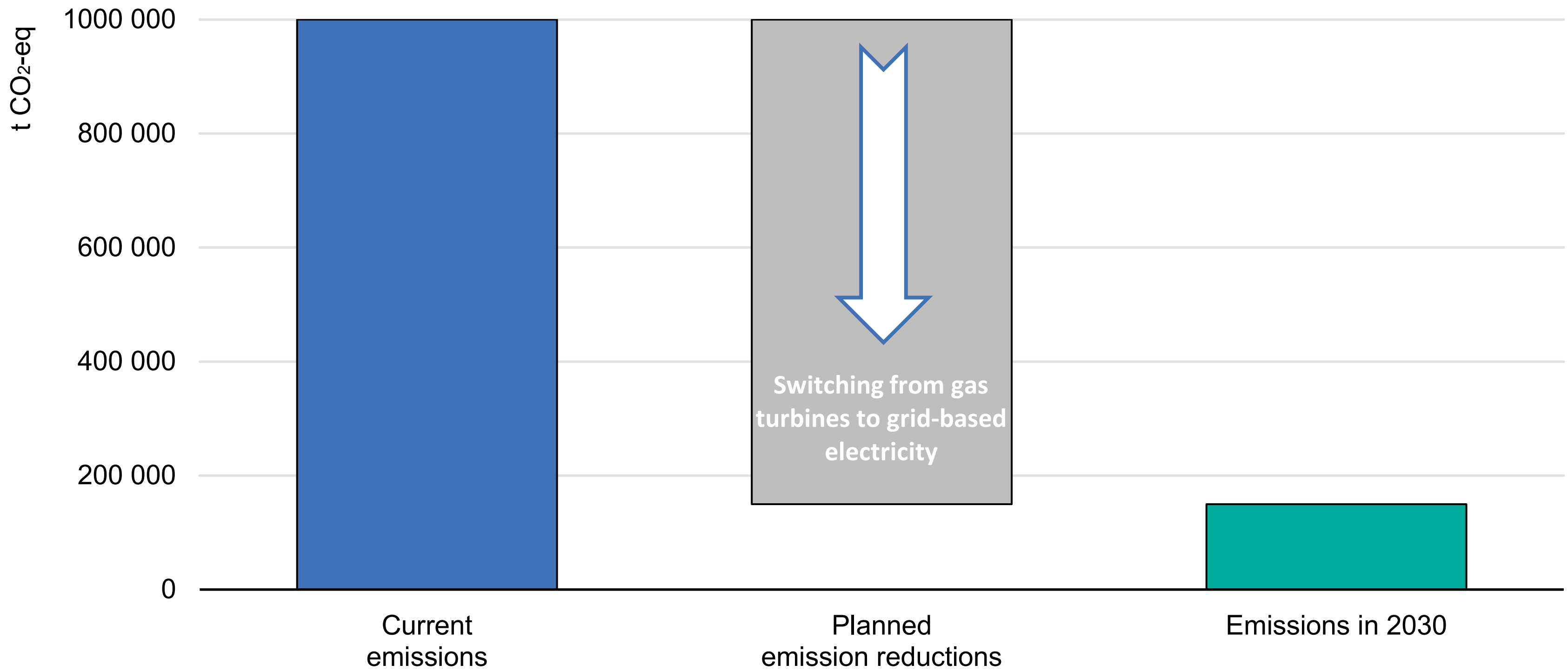
Norway was the world's third largest net exporter of natural gas in 2023, standing behind Qatar and Russia. The country supplied 110 bcm of piped gas and around 6 bcm of LNG, with 90% of its overall exports delivered to the European market. The emissions intensity of Norwegian natural gas is amongst the lowest in the world at around 1.1 t CO_2-eq/m^3 of gas in the case of piped gas. In collaboration with the industry, the Norwegian government aims to reduce GHG emissions from the oil and gas production on the Norwegian continental shelf by 50% by 2030 (compared with 2005) and to net zero by 2050.

The **carbon tax** and the **EU Emissions Trading System** (EU ETS) are the main instruments of climate policy on the Norwegian continental shelf. Currently the EU ETS applies to about 95% of GHG emissions from the oil and gas industry. In addition, almost all GHG emissions from Norwegian gas production are subject to a special CO_2 tax, currently around USD 75/t. Hence, in Q1 2023 the average cost of CO_2 emissions (EU ETS plus CO_2 tax) amounted to approximately USD 160/t. The government has announced that it will gradually increase the CO_2 tax on the Norwegian continental shelf. These policy instruments give companies strong economic incentives to reduce GHG emissions. **Gas flaring has been generally prohibited since 1971** when petroleum activities began on the Norwegian continental shelf. It is only permitted when necessary for safety reasons. In addition, there is a requirement to use the **best available technologies** (BAT). This in turn results in stricter requirements for the use of technology to reduce emissions. Several new field developments are being planned and developed with power from shore (connected to the onshore electricity grid) and some existing fields are switching from gas turbines to power from shore. This substantially lowers emissions. Norway has made a significant effort over the long term to measure and understand the level of emissions from offshore sites.

Norway's **Hammerfest LNG** annually emits around 1 Mt CO_2-eq (1 t CO_2/m^3 of natural gas). CO_2 in the well stream from the Snøhvit field is separated at the LNG plant and returned to the field for permanent geological storage. Approximately 700 000 t CO_2/yr is captured and stored. In August 2023 Norway's government approved the Snøhvit partners' plans for the future operation of Snøhvit and Hammerfest LNG. Under the **Snøhvit Future project**, the current gas turbine generators will be replaced by electric compressors fed by renewable power from shore. This will reduce the plant's CO_2 emissions by around 850 000 tonnes (or 85%) starting in 2030. In addition, onshore compression is expected to increase LNG production by a total of 60 bcm through the period 2028-2043.

Norway is expecting to decrease its emissions from LNG production by 80% by 2030

Current and expected GHG emissions from Hammerfest LNG



Source: IEA analysis based on Equinor (2023), Governmental green light to the Snøhvit Future project.

Canada's pioneering commitment: Aiming for a 75% reduction in methane emissions by 2030

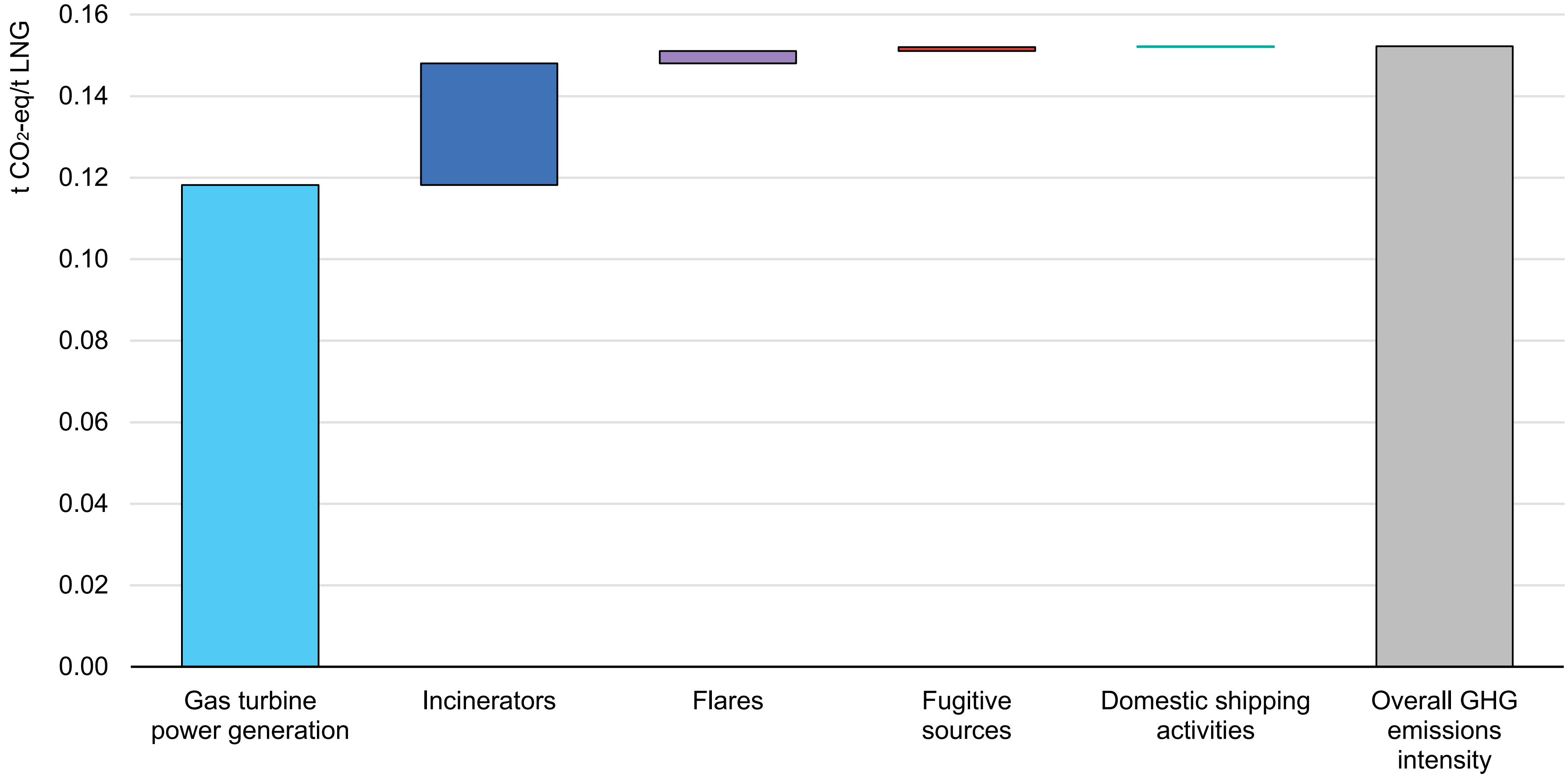
Canada is the world's fourth-largest gas producer and a major pipeline gas exporter to the United States. The country's first large-scale LNG export facility, LNG Canada (19 bcm/yr), is set to start commercial operations by the mid-2020s. Canada is committed to achieving **net zero emissions by 2050** and has set an interim target of reducing GHG emissions by 40-45% below 2005 levels by 2030. Canada continues to develop and implement policies to reduce the GHG emissions along its gas supply chains:

- **Canadian Net-Zero Emissions Accountability Act**: This act legally mandates governments to plan, report and adjust net zero strategies towards 2050, including in the natural gas sector.
- **Carbon pollution pricing**: Canadian natural gas activities are subject to carbon pricing under federal or provincial systems to incentivise investment in clean energy innovation.
- **Methane emissions reduction**: Federal regulations require the oil and gas sector to reduce methane emissions by 40-45% below 2012 levels by 2025. In December 2023 the government published the Draft Oil and Gas Methane Regulations Amendments, targeting a reduction of at least 75% in oil and gas sector methane emissions from 2012 levels by 2030.
- **Clean Fuel Regulations**: These regulations require suppliers to gradually reduce the carbon intensity of the fuels produced and sold for use in Canada.
- **Emissions Reduction Fund**: This CAD 750 million programme is helping Canadian oil and gas companies invest to reduce methane and other GHG emissions.
- **Investment in CCUS**: Canada is investing CAD 319 million to advance the commercial viability of CCUS through Canada's Energy Innovation Program. The government of Canada has delivered on its G20 commitment to phase out inefficient fossil fuel subsidies.

Natural gas in Canada was first **certified** in 2020 and according to industry surveys 10-15% of gas production was already certified in 2022. Furthermore, the Canadian natural gas industry is taking steps to **decrease upstream and midstream emissions** through various methods, including electrification, reducing flaring, detecting and repairing residual emissions leaks, using CCUS, and anticipated future process enhancements. Notably, **LNG Canada Phase 1**will have an emissions intensity of around 0.15 t CO_2-eq/t LNG – well below the global average of GHG emissions at LNG plant level. This is due to the lower CO_2 composition of the feedgas supply, widespread electrification of upstream operations, the high share of hydropower in the electricity grid and the use of highly efficient gas turbines at the liquefaction plant. Several other planned LNG facilities in Canada are aiming to be fully electrified, limiting their emission intensity to 0.02-0.08 t CO_2/t LNG.

LNG Canada Phase 1 is expected to have an emissions intensity of 0.15 t CO_2-eq/t LNG

Estimated GHG emissions intensity of LNG Canada Phase 1 by operation



Source: IEA analysis based on Impact Assessment Agency of Canada (2015), LNG Canada Export Terminal Project Assessment Report.

Japan advances GHG emissions reduction through closer dialogue between LNG producers and consumers

Japan was the world's **second-largest LNG importer** in 2023, with the country's LNG inflows amounting to 90 bcm. Considering its position as one of the world's largest LNG markets, Japan was a major driving force behind **closer dialogue between LNG producers and consumers**. The LNG Producer–Consumer Conference has been organised since 2012 and is serving as a key forum to enhance international co-operation on a range of issues, including gas supply security and the reduction of methane emissions along LNG value chains.

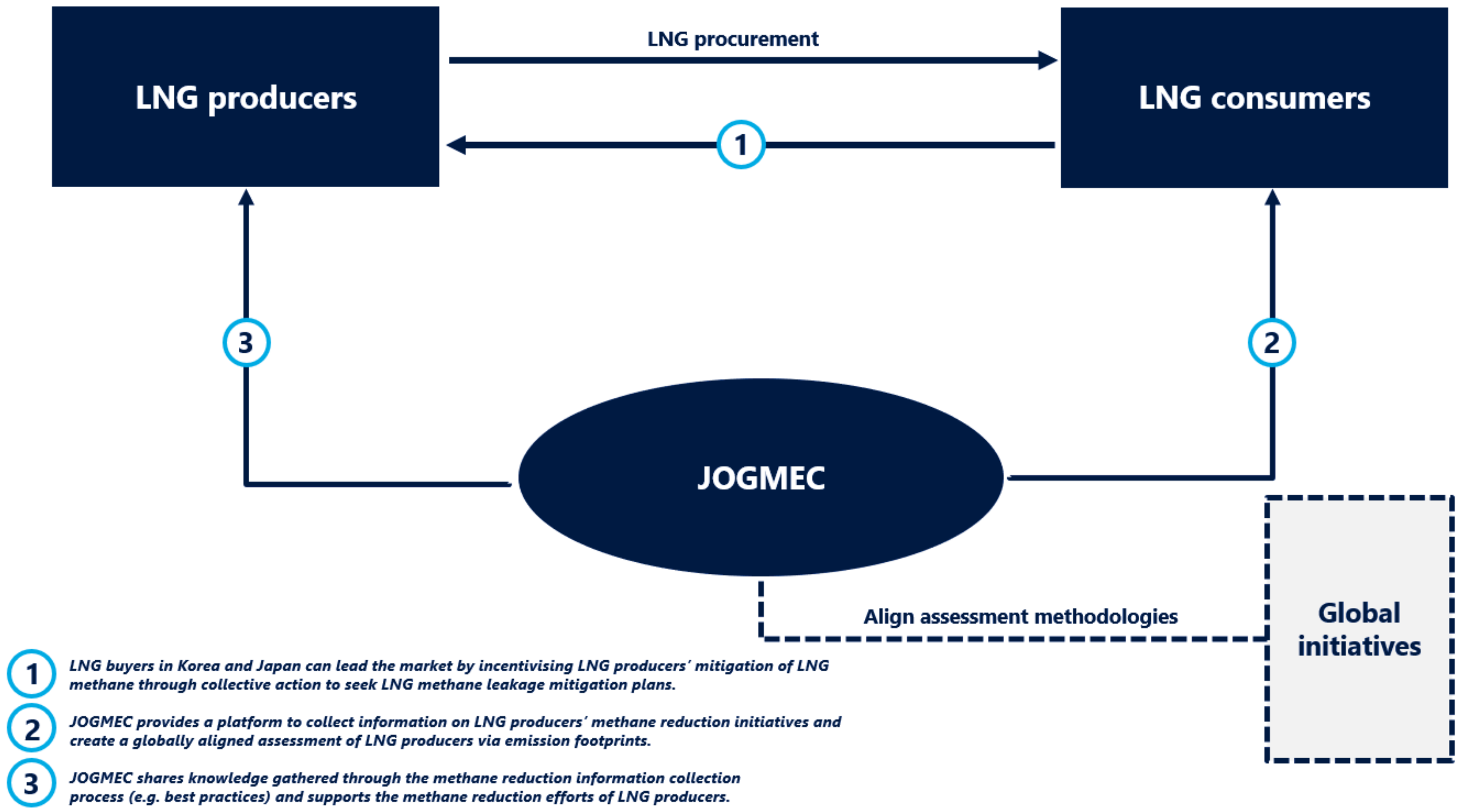
At the **LNG Producer–Consumer Conference 2023**, which Japan co-hosted with the IEA, a public–private initiative to reduce methane was announced. KOGAS, the largest LNG buyer in South Korea, JERA, the largest LNG buyer in Japan, and JOGMEC, a Japanese public organisation, launched an initiative called **CLEAN** (Coalition for LNG Emission Abatement towards Net-zero) to reduce methane emissions in the LNG value chain.

As a part of this initiative, Japan's Ministry of Economy, Trade and Industry (METI) and JOGMEC are working together to collect information on the status of methane emission management and emission reduction efforts for each LNG project and are planning to publish this information together with best practices under the CLEAN initiative. Through this programme, Japan aims to facilitate the establishment of cleaner LNG supply chains by enhancing the visibility of methane emissions. **JERA and KOGAS** will send a questionnaire to the LNG producers to inquire about the status of methane emission management and emission reduction efforts undertaken at their respective LNG projects. JOGMEC will support the programme as co-ordinator. It will establish an information platform to enhance the visibility of LNG-related methane emission reduction initiatives and to disseminate best practices. Japan aims to expand the CLEAN initiative to other LNG buyers in the future.

A **Joint Statement on Accelerating Methane Mitigation from the LNG Value Chain** was signed at the LNG Producer–Consumer Conference 2023 by Australia, the European Commission, Japan, Korea and the United States. The signatory parties affirmed their support for the creation of an internationally aligned **voluntary approach** for the measurement, monitoring, reporting and verification of GHG emissions across the international supply chain for natural gas. The parties expressed their strong support for accelerated methane reductions along the LNG value chain by **both public and private stakeholders**. Moreover, **Japan and the European Union** agreed to reinforce energy co-operation through a dedicated dialogue on the global LNG architecture, including the reduction of methane emissions.

Public-private efforts are enhancing transparency on LNG-related methane emissions and facilitating the sharing of best practices

A simplified scheme of the Coalition for LNG Emission Abatement towards Net-zero (CLEAN) initiative



Source: IEA analysis based on JOGMEC (2023), Coalition for LNG Emission Abatement toward Net-zero – Sharing LNG project-level methane reduction measures.

The European Union agreed to adopt a new regulation on methane emissions

The European Union is the world's largest natural gas and LNG import market, with import volumes totalling 295 bcm in 2023. Following Russia's invasion of Ukraine, the European Union's LNG imports rose by 65% in 2022 and reached an all-time high of 128 bcm. **LNG effectively became a baseload supply source** and is expected to retain a 35-40% share of the European Union's total natural gas supply over the medium term.

The European Commission put forward a **Methane Strategy** in October 2020. It focuses both on reducing methane emissions in the European Union and addressing methane emissions associated with supply chains linked to the European Union.

The European Commission published its legislative proposal for a regulation on methane emissions reduction in the energy sector in December 2021. In November 2023 the Council and the European Parliament reached a political agreement on the **new EU methane regulation**, which is set to be adopted in 2024.

The regulation will contain the following measures:

- Requiring operators to **report regularly** to the competent authorities on the quantification and measurement of methane emissions at source level, including for non-operated assets.
- Obliging oil and gas companies to carry out **regular surveys** of their equipment to detect and repair methane leaks on EU territory within specific deadlines.
- **Banning routine venting and flaring** by the oil and gas sectors and restricting non-routine venting and flaring to unavoidable circumstances, for example for safety reasons or in the case of equipment malfunction.
- **Limiting venting from thermal coal mines** from 2027, with stricter conditions in place after 2031.
- Requiring companies in the oil, gas and coal sectors to carry out an **inventory of closed, inactive, plugged and abandoned assets**, such as wells and mines, to monitor their emissions and to adopt a plan to mitigate these emissions as soon as possible.

This regulation will also tackle the **methane emissions related to imports**:

- It establishes a **methane transparency database** where data on methane emissions reported by importers and EU operators will be made available to the public.

- It requires the Commission to establish **methane performance profiles** of countries and companies to allow importers to make informed choices on their energy imports.

- The Commission will also put in place a **global methane emitters monitoring tool** and a **rapid alert mechanism** for super-emitting events, with information on the magnitude, recurrence and location of high methane-emitting sources both within and outside the European Union. As part of this tool, the Commission will be able to request prompt information on action to address these leaks by the countries concerned;

- As of January 2027 the regulation requires that new import **contracts for oil, gas and coa**l can be only concluded if the same monitoring, reporting and verification obligations are applied to exporters as they are to EU producers.

- The regulation will set out a **methane intensity methodology and maximum levels** to be met for oil, gas and coal from 2030.

In addition, the European Union is taking active part in **international initiatives** and co-operation frameworks related to the reduction of methane emissions. In 2021 the Commission supported the establishment of the **International Methane Emission Observatory** (IMEO) together with UNEP, the Climate and Clean Air Coalition and the IEA. President von der Leyen and President Biden launched the **Global Methane Pledge** (GMP) at COP26 in 2021 in Glasgow to reduce methane emissions by 30% by 2030. In June 2022 a **GMP Energy Pathway** was launched at the Major Economies Forum on Energy and Climate to accelerate methane emissions reductions in the fossil energy sector. At COP27 in November 2022 the European Union confirmed its commitment on methane emissions reduction by endorsing a **Joint Declaration on Reducing Greenhouse Gas Emissions from Fossil Fuels**, together with the United States, Japan, Canada, Norway, Singapore and the United Kingdom. Together they represent 50% of global gas import volumes and over 30% of global gas production.

At COP28 in December 2023 the European Union and its member states announced EUR 375 million in support for the **Methane Finance Sprint** to boost methane reductions. The European Commission also announced that it will develop a roadmap for the global rollout of the **"You Collect, We Buy"** scheme by COP29. The scheme incentivises companies to capture and commercialise gas that would be otherwise be vented or flared.

The European Union is also part of the **MMRV International Working Group**, which was established in November 2023 to develop comparable and reliable information for natural gas market participants on methane emissions.

Low-emissions gases

Low-emissions gases continued to benefit from a wide range of policy initiatives in 2023

Low-emissions gases (including biomethane, low-emissions hydrogen[6] and e-methane[7]) can play a crucial role in decarbonising gas supply chains and the broader energy system. Recognising their growing importance, the IEA has developed a **Low-emissions Gases Work Programme** to track closely market developments in this sphere and facilitate dialogue between emerging producers and consumers. This section provides an overview of the key policy and market developments related to low-emissions gases in 2023.

European Union

Low-emissions gases are an integral part of the the European Union's efforts to decarbonise its energy system and reduce its reliance on fossil fuel imports. The non-binding **REPowerEU Plan** sets targets for EU renewable hydrogen production of 10 Mt/yr and renewable hydrogen imports of 10 Mt/yr by 2030, and includes a proposal to scale up biomethane production to 35 bcm/yr by 2030.

European Commission President Von der Leyen announced the creation of the **European Hydrogen Bank** (EHB) in her State of the Union Speech in September 2022. In March 2023 the European Commission published its EHB Communication to describe the bank's tasks and structure. It is expected to facilitate investment in hydrogen projects both in the European Union and in third countries. In November 2023 the Commission launched the **first auction under the EHB** for domestic projects, supported by an initial budget of EUR 800 million from the Innovation Fund. Under the auction, renewable hydrogen producers bid for a fixed premium to bridge the gap between their production costs and the price consumers are currently willing to pay.

In December 2021 the European Commission proposed a **hydrogen and decarbonised gas market package** to establish common market rules for renewable and natural gases as well as hydrogen. The Council and the European Parliament reached a provisional agreement on the proposal in December 2023, which is expected to be formally adopted in early 2024.

In line with the current EU natural gas regulation, the new regulatory framework sets guidelines for the gradual implementation of non-discriminatory third-party **access to future hydrogen networks**, blending limits, unbundling, tariffs, network codes and operational transparency. As of 1 January 2033 hydrogen networks will be organised as an entry–exit system and apply rules on third-party access, capacity allocation, congestion management and balancing in a non-discriminatory manner. The new regulation lays down the

[6] Low-emissions hydrogen includes hydrogen produced via electrolysis where the electricity is generated from a low-emissions source (renewables or nuclear), biomass or fossil fuels with CCUS (please refer to a detailed definition in the Global Hydrogen Review).

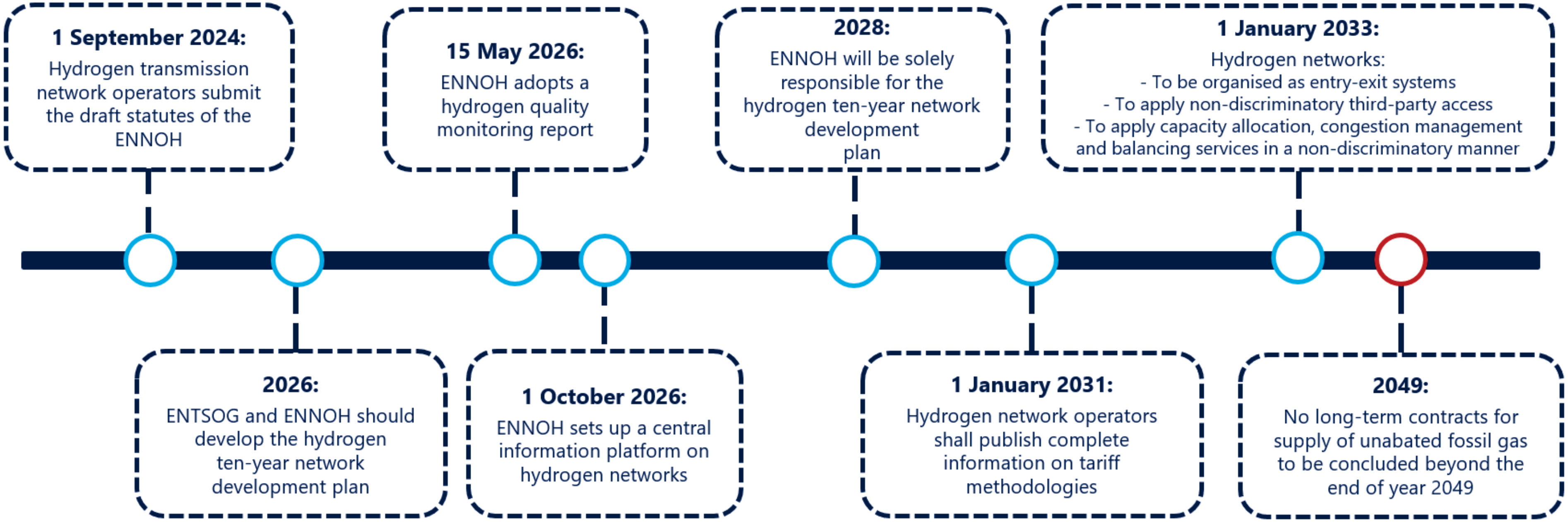
[7] E-methane refers to synthetic methane produced from electrolytic hydrogen. The definition of low-emissions synthetic methane used by the IEA for analytical purposes in its reports considers that any carbon inputs, e.g. from CO_2, are not from fossil fuels or process emissions. Beyond this definition, a commercial proposition for carbon-neutral e-methane could consider the use of CO_2 captured at industrial or power plants and offset through carbon credits (similar to the commercial offers of carbon-neutral LNG).

legal foundation for the establishment of the **European Network of Network Operators for Hydrogen** (ENNOH). ENNOH will consist of certified hydrogen transmission network operators in member states. By 1 September 2024 hydrogen network operators are required to submit to the European Commission and the EU Agency for the Cooperation of Energy Regulators (ACER) the draft statutes and procedural rules of ENNOH that have yet to be established. From 1 October 2026 ENNOH will operate a central web-based platform to provide market participants with all the relevant information necessary to access the hydrogen network. In addition, ENNOH will be responsible for developing ten-year hydrogen network development plans starting from 2028.

The new regulatory framework also supports the scale-up and gas system integration of biomethane. Member states may grant biomethane production facilities **priority access** to the gas network. Moreover, a discount of 100% may be applied to the respective capacity-based tariffs at entry points from renewable gas production facilities. The **tariff reductions** will be re-examined every five years. In order to facilitate the integration of biomethane into the wholesale market, production facilities connected to the distribution grid should have **access to the virtual trading point**. Hence, distribution system operators and transmission system operators should work together to enable **reverse flows** from the distribution to the transmission network or to ensure the integration of the distribution system through alternative, equivalent means. The European **supply adequacy outlook** – to be produced by the European Network of Transmission System Operators for Gas (ENTSOG) every two years – will include a monitoring of the annual production of sustainable biomethane in the European Union.

In addition to EU-level policies and regulations, several EU member states have adopted new strategies and measures to support the scale-up of low-emissions gases. **Germany** adopted its National Hydrogen Strategy Update in July 2023. The revised strategy assumes total hydrogen demand of 95-130 TWh/yr by 2030, up from a range of 90-110 TWh/yr in the previous version. In light of stronger demand, the updated strategy doubles the national target for electrolyser capacity from 5 GW to at least 10 GW by 2030. The strategy foresees the build-up of a 1 800 km long hydrogen network by 2027/28. While developing its hydrogen sector, Germany also expects to become the lead provider of hydrogen technologies by 2030. In July 2023 **Ireland** published its National Hydrogen Strategy, which includes a target for 2 GW of offshore wind for the production of renewable hydrogen to be in development by 2030. At the end of August 2023 **France** announced EUR 4 billion of support for the development of "low-carbon hydrogen". Under the support scheme, France will hold its first tender for 150 MW of electrolyser capacity in 2024, followed by 250 MW in 2025 and 600 MW in 2026. At the end of 2023 France launched a consultation process on its new Hydrogen Strategy, targeting 6.5 GW of electrolyser capacity by 2030 and 10 GW by 2035. A number of other EU countries announced support for biomethane production in 2023. This is detailed under the biomethane section.

The Hydrogen and Decarbonised Gas Markets Package lays the foundations for the future European low-emissions gas market



Notes:
ENTSOG = European Network of Transmission System Operators for Gas.
ENNOH = European Network of Network Operators for Hydrogen.

Sources: IEA analysis based on European Council (2023), Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast); European Council (2023), Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast).

United States

Low-emissions gases can play a key role in reaching the United States' goal to reduce GHG emissions by 50-52% below 2005 levels by 2030. The United States published its **National Clean Hydrogen Strategy and Roadmap** in June 2023. The strategy identifies the opportunity to scale up clean hydrogen production to 10 Mt/yr by 2030, 20 Mt/yr by 2040 and 50 Mt/yr by 2050. This would reduce US economy-wide GHG emissions by around 10% compared with 2005 levels. The strategy foresees a steep reduction in electrolytic hydrogen production costs from around USD 5/kg in 2020 to USD 1/kg by 2031. These cost reductions will be supported by the **Clean Hydrogen Electrolysis Program**, which aims to improve the efficiency and cost-effectiveness of electrolysis technologies with funding of USD 1 billion. In October 2023 the US Department of Energy announced USD 7 billion of federal support to launch seven **Regional Clean Hydrogen Hubs** (H2Hubs) to accelerate the commercial-scale deployment of clean hydrogen. The seven H2Hubs are expected to produce in total 3 Mt/yr of clean hydrogen by 2030.

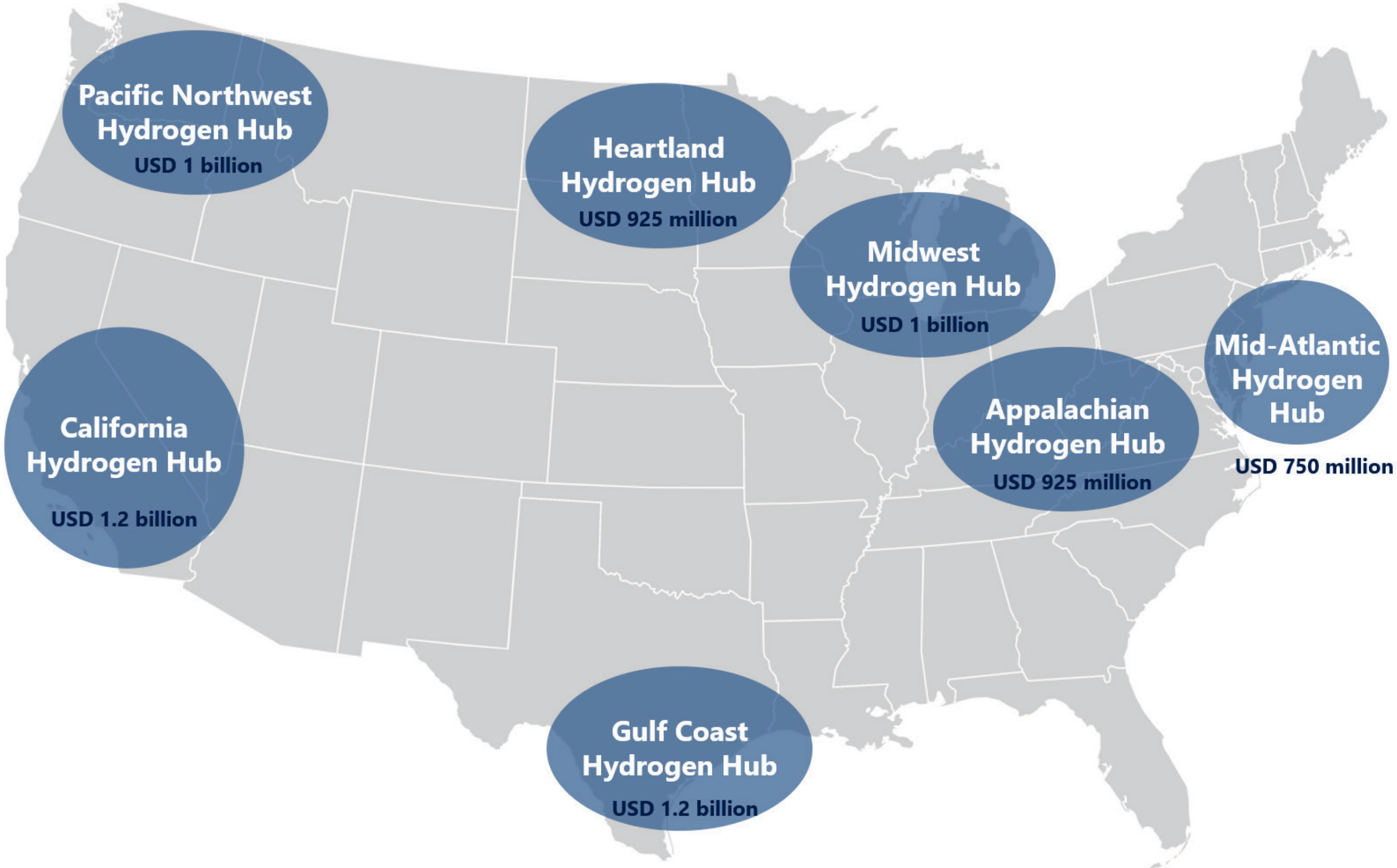
Biomethane in the United States is set to benefit from more stringent fuel standard requirements. In June 2023 the Environmental Protection Agency established biofuel volume requirements and standards for cellulosic biofuel (which primarily apply to biomethane) for 2023-2025 as part of the Renewable Fuel Standard (RFS) program. The new rule increases volume targets for cellulosic biofuel by 25% in 2023, 29% in 2024 and 33% in 2025 compared with the previous target. Based on the revised targets, US biomethane production could double from its 2022 levels to around 4 bcm by 2025.

Asia

Japan published its **Basic Hydrogen Strategy** in June 2023, an update of its 2017 Hydrogen Strategy. The revised strategy aims to scale up domestic hydrogen demand to 3 Mt/yr by 2030, 12 Mt/yr by 2040 and 20 Mt/yr by 2050. In addition the strategy sets a target for Japanese companies to install 15 GW of electrolyser capacity globally by 2030. The strategy sets a target for a hydrogen supply cost of JPY 334/kg (USD 2.30/kg) by 2030 and JPY 222/kg (USD 1.55/kg) by 2050. It recognises the potential contribution of **e-methane** to energy supply security and the need to develop international partnerships with producing economies.

India approved its **National Green Hydrogen Mission** in January 2023. The mission sets a target for at least 5 Mt/yr of green hydrogen production by 2030, "with potential to reach 10 Mt/yr with growth of export markets". It proposes two distinct financial incentive schemes to support domestic manufacturing of electrolysers, as well as the production of green hydrogen. The initial outlay of the mission is around USD 2.4 billion. In November 2023 India approved mandatory blending of **compressed biogas** into the domestic gas supply. The mandate will be set at 1% of total compressed natural gas and domestic piped natural gas consumption from 2025, and raised gradually to 5% from 2028/29.

Seven hubs were selected in 2023 to receive funding under the Regional Clean Hydrogen Hubs programme



Source: IEA analysis based on Department of Energy (2023), Biden-Harris Administration Announces $7 Billion For America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide.

Biomethane continued to expand strongly in 2023…

Global biomethane production increased by an estimated 12% (or around 0.8 bcm) in 2023 to reach almost 8 bcm. This strong growth was driven by the United States and the European Union, together accounting for 80% of incremental biomethane supply.

The **United States** further solidified its position as the world's largest producer of renewable natural gas (RNG, the equivalent of biomethane in North America) in 2023. Biomethane output increased by an estimated 10% (or 0.2 bcm) and reached almost 2.2 bcm. Hence, the United States alone accounted for around 20% of incremental biomethane production in 2023. This strong growth is primarily driven by the **transport sector** and the Renewable Fuel Standard (RFS) set by the Environmental Protection Agency. Around 90% of RNG is consumed as a transport fuel and less than 10% is used for power generation. In terms of feedstock, **municipal solid waste** accounts for almost 70% of biomethane production, followed by agricultural waste (20%), food waste (5%) and waste water (5%). At the end of 2023 the United States had 311 operational biomethane production facilities, with 177 under construction and 360 planned, as per the RNG Coalition.

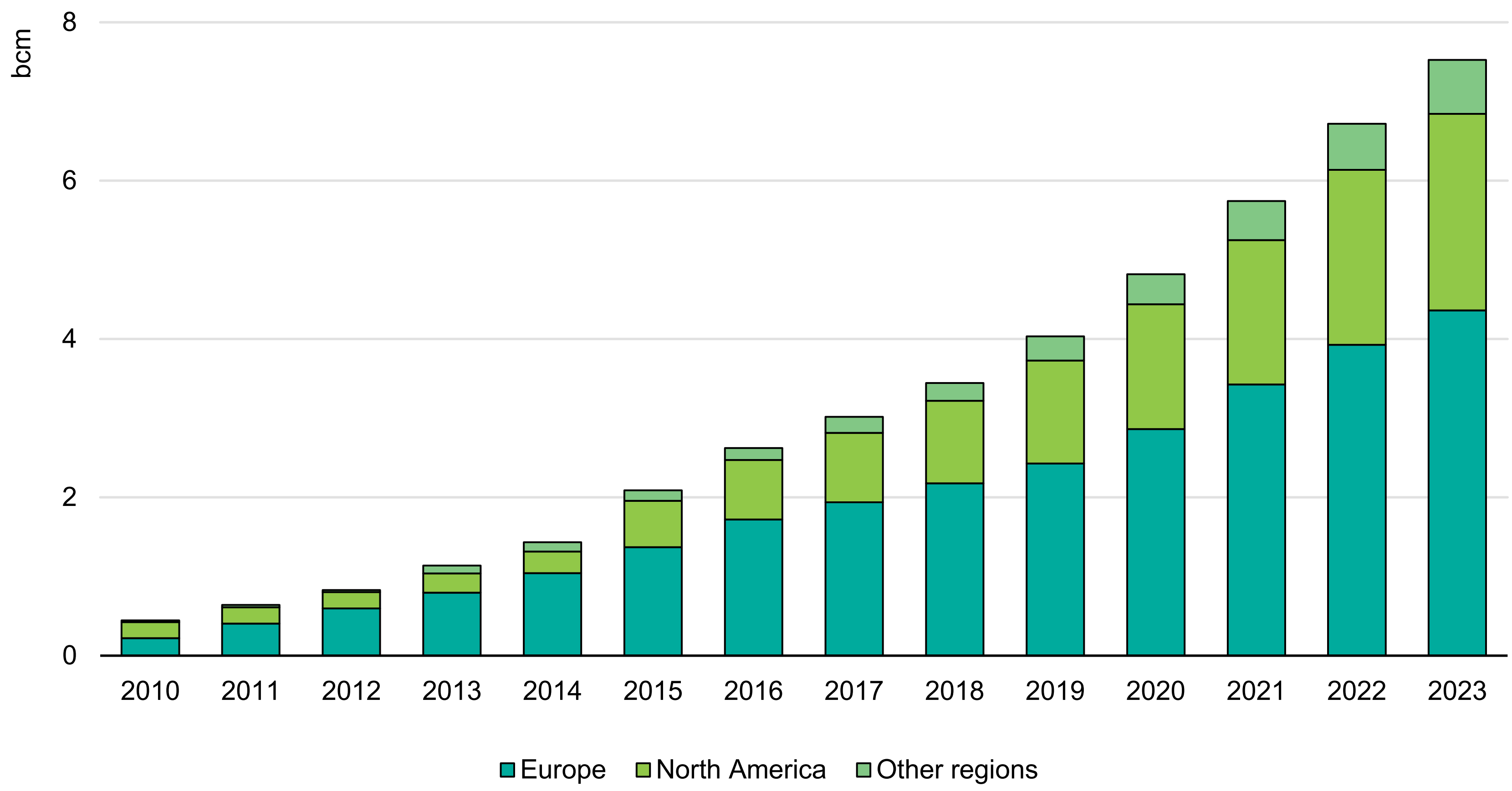
Biomethane production in 2023 grew by just over 10% (or more than 0.4 bcm) in **Europe**, primarily supported by Denmark and France. Renewable natural gas output in **Germany** – Europe's largest biomethane market – remained broadly flat compared to 2022. In contrast, biomethane output increased by close to 30% (or 0.2 bcm) in **France** to around 0.9 bcm, making it Europe's second-largest biomethane producer ahead of Denmark. This strong growth has been enabled by the country's agricultural sector, with agricultural waste accounting for almost 80% of the feedstock. Biomethane production continued to expand in **Denmark**, growing by almost 15% (or 0.1 bcm) in 2023 to around 0.8 bcm. Consequently, the share of biomethane in Denmark's total natural gas demand increased from 32% in 2022 to a record 38% in 2023.

In addition to these more mature biomethane producers, a number of other European markets are aiming to boost biomethane production in the coming years. In **Italy**, the National Recovery and Resilience Plan (PNRR) allocated EUR 1.7 billion to support the country's biomethane production. In November 2023 Italgas and farming assocition Coldiretti signed an agreement to quadruple Italy's biomethane production to 2 bcm/yr by 2026. In the **Czech Republic**, a scheme backed by EUR 2.4 billion will support the construction and operation of biomethane production plants. The support scheme will run until the end of 2025 and is expected to ramp up biomethane output to close 0.34 bcm/yr. In **Ireland**, the country's Climate Action Plan set a target of producing 5.7 TWh/yr (or 0.5 bcm/yr) of biomethane by 2030. **Ukraine**'s first biomethane plant was connected to the gas network in April 2023.

Besides Europe and North America, biomethane production is also increasing in Brazil, China and India.

…primarily supported by Europe and North America

Biomethane production by region, 2010-2023



Sources: IEA analysis based on Argonne National Laboratory (2024), Renewable Natural Gas Database; Biogas Partner (2024), Biogaspartner Einspeiseatlas Deutschland; Cedigaz (2023), Global Biomethane Database; Energinet (2024), Energi Data Service; ODRE (2024), Production Quotidienne Consolidée de Biométhane sur le réseau de transport et de distribution par Opérateur.

Hydrogen pipeline project developments take off in Europe

The large-scale deployment of low-emissions hydrogen will require an effective and cost-efficient transmission system, connecting supply sources with demand centres. Recognising the strategic importance of developing a suitable hydrogen network, European governments and transmission system operators are setting targets for hydrogen infrastructure development. A particular focus is placed on the potential **repurposing of gas pipelines** to serve hydrogen, as this can reduce investment costs by 50-80% compared to new pipelines. Based on public announcements, close to **30 000 km of hydrogen pipelines** could be available by the early 2030s. Only a small fraction of those projects have reached final investment decision (FID) or are under construction.

In the **Netherlands**, Gasunie took FID on the first phase of the country's planned hydrogen network. Construction works started in October, a first section of 30 km being built in Rotterdam to connect the Tweede Maasvlakte industrial park to Pernis. The hydrogen pipeline is expected to be operational by 2025. The national hydrogen network would ultimately have a length of 1 200 km and will connect the Netherlands' major industrial areas to each other and to Germany and Belgium. The overall costs associated with its development are estimated at EUR 1.5 billion. Around 85% of the network would consist of repurposed natural gas pipelines.

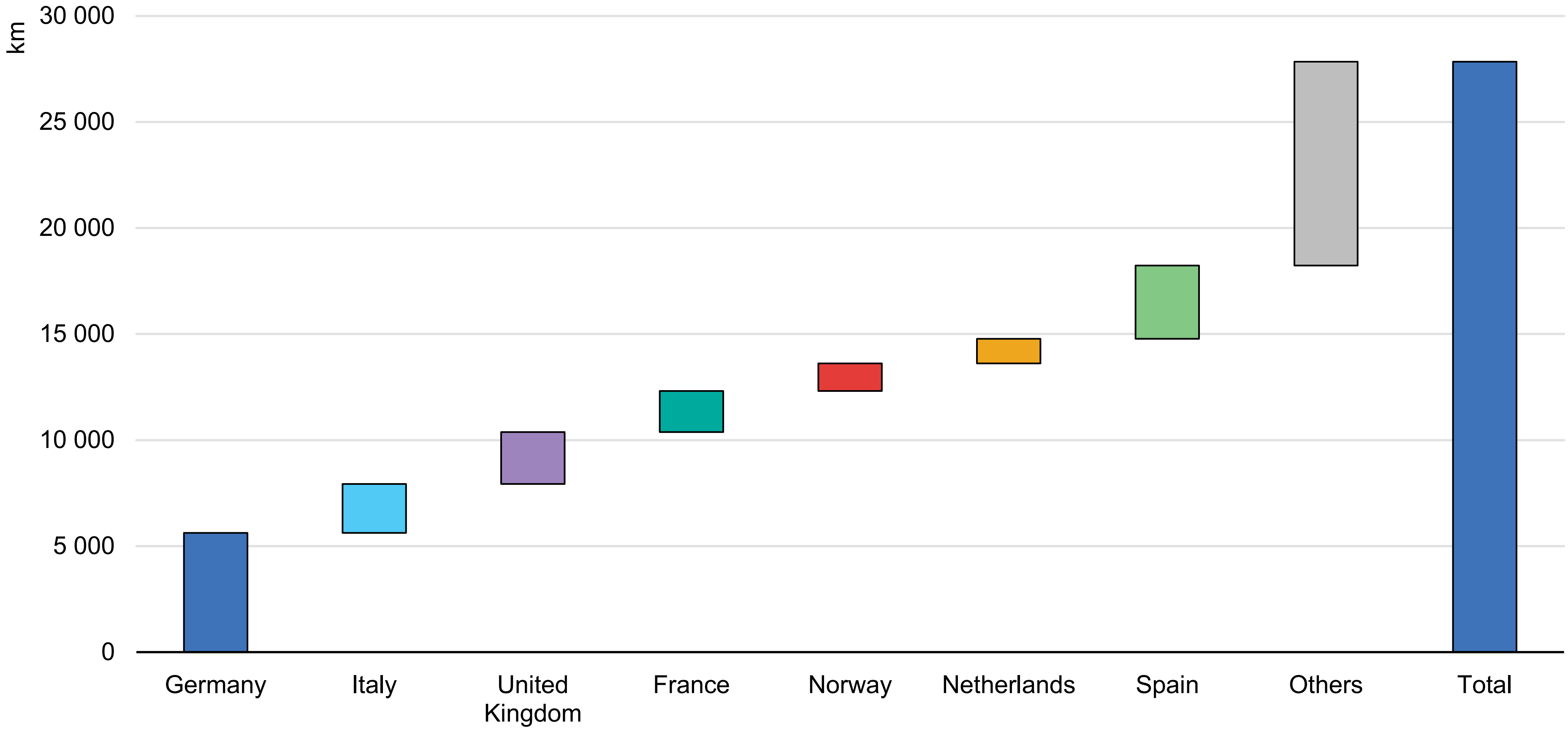
In **Germany**, the country's 2023 National Hydrogen Strategy Update foresees the development of a hydrogen network of 1 800 km by 2027/28. Germany's association of supra-regional gas transmission companies (FNB Gas) presented a draft concept of the hydrogen core network in November 2023. In their view, the lenghth of the network is expected to total 9 700 km by 2032 at an overall cost of EUR 19.8 billion. Reused natural gas pipelines are expected to account for around 70% of this future hydrogen network. In October, gas transmission operators OGE and Nowega started the conversion of a 46 km gas pipeline segment to hydrogen service. The pipeline runs from Lower Saxony to North Rhine-Westphalia and is expected to carry hydrogen by 2025.

The revised regulation on trans-European energy infrastructure (TEN-E) set **three priority corridors** for the development of hydrogen infrastructure in the European Union, with a focus on Western Europe (HI West), Central Eastern and South Eastern Europe (HI East) and the Baltic Energy Market Interconnection Plan for Hydrogen (BEMIP Hydrogen). In November 2023 the European Commission published a list of **Projects of Common and Mutal Interest** (PCI/PMI). Of the 166 selected projects, 31 relate to the development of hydrogen pipelines along the three priority corridors identified in the TEN-E regulation. Receiving the PCI/PMI status allows project developers to apply for funding under the Connecting Europe Facility (CEF), which could facilitate reaching FID.

The upcoming IEA Northwest European Hydrogen Monitor will provide a review of hydrogen pipeline projects in northwest Europe.

Nearly 30 000 km of hydrogen pipelines could be built in Europe by the early 2030s

Hydrogen pipelines in Europe planned for completion by the early 2030s



Note: Norway's planned hydrogen pipelines include both upstream Norwegian pipelines and interconnectors.

Sources: IEA (2024), Hydrogen Production and Infrastructure Projects Database.

International co-operation on e-methane continued to strengthen in 2023

E-methane is produced by combining low-emissions hydrogen with a carbon source. Being almost identical to natural gas, it has the potential to contribute to the decarbonisation of existing gas networks without the need for retrofitting. Considering that e-methane is still in the early phase of development, **international co-operation** between producers and consumers is required to facilitate R&D and demonstration projects.

In May 2023 **Francegaz and the Japan Gas Association** (JGA) signed a memorandum of understanding to co-operate on implementing and expanding the use of "low-carbon methane, including e-methane and biogas". The co-operation between the two associations will focus on developing international GHG accounting rules and R&D on production and supply technologies for such gases.

Japan's Ministry of Economy, Trade and Industry (METI), the US Department of Energy, the National Energy Technology Laboratory (NETL), and the New Energy and Industrial Technology Development Organization (NEDO) held the **US–Japan CCUS/Carbon Recycling Working Group** in August 2023. The working group stressed that carbon recycled fuels, including e-methane, can utilise existing infrastructure and contribute to energy security. The working group confirmed the need to build consensus to ensure that carbon recycled fuels are treated as carbon-neutral when traded internationally.

In addition, **Japanese utilities and trading companies** are actively promoting international co-operation at a corporate level to develop e-methane supply chains with LNG-exporting countries. While no binding agreements have been reached yet, recent project proposals by Japanese companies could potentially enable 0.7 bcm/yr of e-methane imports into Japan by 2030.

In **Europe**, several e-methane projects are being undertaken. In **Finland**, Koppö Energia is developing a project to produce e-methane. The project aims produce 55 000 tonnes/yr in Kristinestad, Finland, which would be liquefied for use as a clean fuel in the heavy transport sector. An investment decision is expected in 2024. The Columbus project in Wallonia, **Belgium**, has moved to front-end engineering design (FEED) studies. This project aims to produce low-emissions hydrogen using a 100 MW electrolysis unit, capture CO_2 and convert H_2 to e-methane on an industrial scale. The aim is to take FID in 2024.

In the **United States**, TotalEnergies and Tree Energy Solutions are considering developing a large-scale e-methane production unit with an output in the range of 0.15-0.3 bcm/yr. In September 2023 Tree Energy Solutions and ADNOC announced a strategic collaboration to undertake a joint feasibility study to explore e-methane production in the **United Arab Emirates and the United States**. In November 2023, Tree Energy Solutions announced plans to produce e-methane in Canada.

Japanese companies are leading the development of international e-methane supply chains

Key planned e-methane import projects led by Japanese companies

Companies involved	Potential import country	Potential production volumes	Description of the project
Osaka Gas USA, Tallgrass and Green Plains	United States	0.20 Mt/yr by 2030	Agreement to conduct a feasibility study on e-methane production at the Freeport LNG export terminal in the United States.
Osaka Gas Australia and Santos	Australia	0.06 Mt/yr by 2030	Pre-front-end engineering and design work on a project to produce e-methane from low-emissions hydrogen in Australia for export to Japan and other markets.
Marubeni, Osaka Gas and Peru LNG	Peru	0.06 Mt/yr by 2030	A project to study the production of e-methane in Peru and its delivery to Japan, within Peru and to other areas.
Tokyo Gas, Osaka Gas, Toho Gas, Mitsubishi Corporation and Sempra Infrastructure	United States	0.13 Mt/yr by 2030	Agreement to conduct a feasibility study of the production of e-methane at the Cameron LNG terminal in the United States. E-methane supply could reach 0.13 Mt/yr by 2030.
Tokyo Gas and Santos	Australia	0.06 Mt/yr by 2030	Agreement to conduct a feasibility study on e-methane production in Australia and its delivery to Japan.
Toho Gas and Santos	Australia	0.03 Mt/yr by 2030	Agreement to conduct a feasibility study on production of e-methane in Australia and its delivery to Japan.

Sources: IEA analysis based on various public announcements.

Annex

Summary table

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

	Consumption					Production				
	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
Africa	161	169	170	175	180	240	260	251	253	260
Asia Pacific	834	891	877	901	937	622	648	660	669	683
of which China	*325*	*367*	*364*	*391*	*414*	*189*	*205*	*216*	*229*	*239*
Central and South America	142	153	150	149	151	150	148	151	149	153
Eurasia	585	649	622	629	641	866	961	865	832	855
of which Russia	*461*	*516*	*487*	*493*	*503*	*692*	*762*	*672*	*640*	*664*
Europe	576	609	524	488	502	230	222	230	215	220
Middle East	546	562	580	591	605	670	692	716	722	745
North America	1 079	1 091	1 144	1 156	1 173	1 145	1 183	1 232	1 275	1 297
of which United States	*868*	*874*	*919*	*926*	*939*	*954*	*984*	*1021*	*1061*	*1081*
World	**3 924**	**4 124**	**4 067**	**4 089**	**4 190**	**3 922**	**4 112**	**4 105**	**4 116**	**4 214**

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the 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, the Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

Europe – Albania, Austria, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[5,6] the 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, the Netherlands, Norway, Poland, Portugal, Romania, Serbia, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, Ukraine and the United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[5,6] the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the 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, the 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

ACCU	Australian Carbon Credit Unit
ANP	National Petroleum Agency (Brazil)
BIL	Bipartisan Infrastructure Law (USA)
BMC	Colombian Mercantile Exchange (Colombia)
CCUS	Carbon Capture, Utilisation and Storage
CLEAN	Coalition for LNG Emission Abatement towards Net-zero
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
COP	UN Climate Change Conference of Parties
CQPGX	Chongqing Petroleum Exchange (the People's Republic of China)
EIA	Energy Information Administration (United States)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOG	European Network of Transmission System Operators for Gas
EPA	Environmental Protection Agency (USA)
EPIAS	Energy Markets Operations Inc. (Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
ETS	EU Emissions Trading System
EU	European Union
EUR	Euro
FID	final investment decision
FSRU	floating storage and regasification unit
GHGs	greenhouse gases
GIE	Gas Infrastructure Europe
GMP	Global Methane Pledge
HH	Henry Hub
HoA	Head of Agreement
ICE	Intercontinental Exchange
ICIS	Independent Chemical Information Services
IEA	International Energy Agency
IMEO	International Methane Emissions Observatory
IMO	International Maritime Organization
IRA	Inflation Reduction Act (USA)
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
JOGMEC	Japan Organization for Metals and Energy Security
JPY	Japanese yen
KOGAS	Korea Gas Corporation
LNG	liquefied natural gas
MARS	Methane Alert and Response System
METI	Ministry of Economy, Trade and Industry (Japan)
MME	Ministry of Mines and Energy (Brazil)
MMRV	Measuring, monitoring, reporting, and verification
MoU	Memorandum of Understanding
NBP	National Balancing Point (United Kingdom)
NGER	National Greenhouse and Energy Reporting (Australia)
OECD	Organisation for Economic Co-operation and Development
OGDC	Oil and Gas Decarbonisation Charter
OGMP	Oil and Gas Methane Partnership
OSINERG	Energy Regulatory Commission (Peru)
PPAC	Petroleum Planning and Analysis Cell (India)
RSG	Responsibly sourced natural gas

SBL	Strategic Buffer LNG
SMC	Safeguard Mechanism Credit (Australia)
TFFS	Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security
TTF	Title Transfer Facility (the Netherlands)
UGS	underground storage
UNFCCC	United Nations Framework Convention on Climate Change
USD	United States dollar
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/yr	billion cubic metres per year
GJ	gigajoule
GW	gigawatt
kWh	kilowatt hour
MBtu	million British thermal units
Mt	million tonnes
Mt/yr	million tonnes per year
m^3/hr	cubic metres per hour
m^3/yr	cubic metres per year
Nm^3	normal cubic metre
TWh	terawatt hour
t/yr	tonnes per year

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