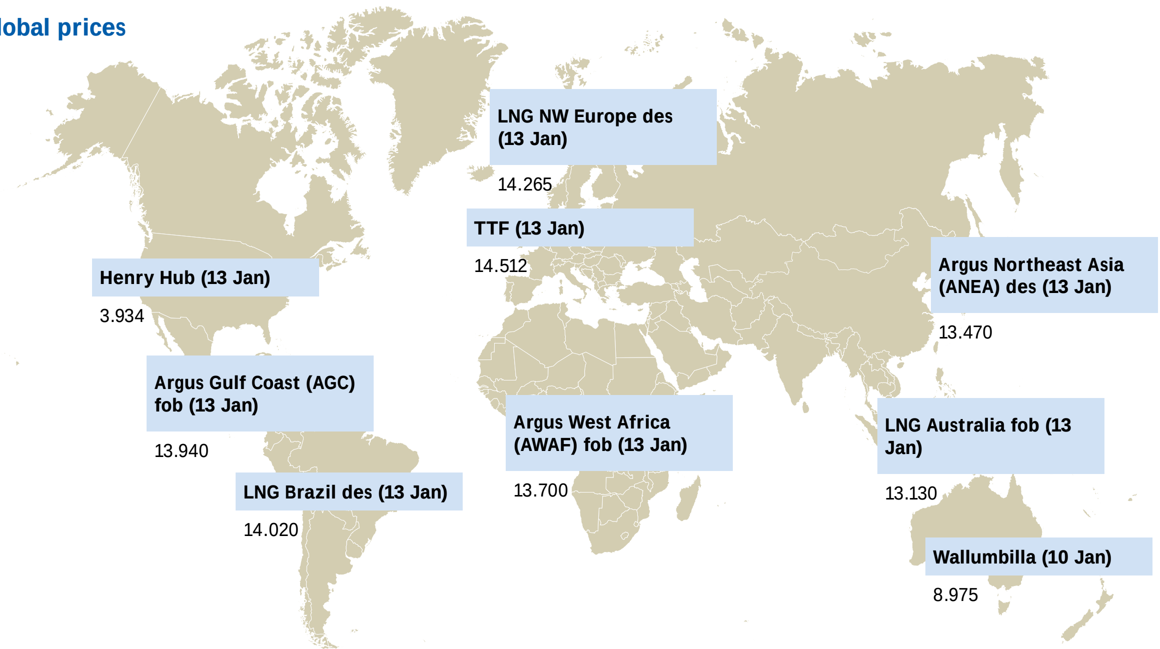
Argus *Global Gas Markets*

Gas and LNG markets, projects and infrastructure

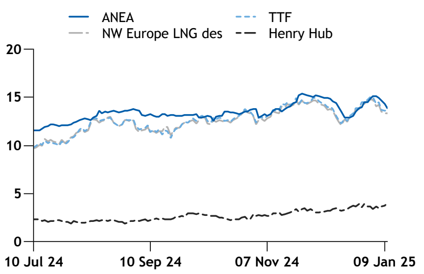
argusmedia.com

Volume II, 1, 15 January 2025

Key global prices *$/mn Btu*



Key global prices *$/mn Btu*



CONTENTS

Executive summary

President-elect Donald Trump will take office on 20 January to an agenda brimming with energy-related issues of extreme complexity.

In its final weeks in office, the outgoing US administration of President Joe Biden has ramped up sanctions on Russian energy exports as well as military aid to Ukraine, which may give the new president more leverage to use in any expected negotiations (*p2*). Eastern European countries now deprived of Russian gas supply (*p3-4*) still hope that the new administration will help normalise energy relations, but this may be at odds with the commercial interests of the US gas industry — which faces challenges despite the support they expect from some of Trump's campaign pledges (*p5*). European gas prices have held at levels that disincentivise their use for power generation in favour of coal in recent weeks (*p11*).

In Asia, continued political turmoil in South Korea is stalling progress on a crucial energy strategy plan (*p6*). In China, state-owned firm Sinopec's projections for this year suggest the country's gas demand growth is set to slow (*p7*). A recent asset swap between major LNG producers Chevron and Woodside may facilitate their respective projects to underpin continued production in Western Australia (*p8*). But eastern Australia is edging closer to having to begin LNG imports this year (*p9*).

Elsewhere, the Brazilian government is hoping to boost supply availability on the domestic market and lower prices by reducing gas reinjections into oil fields and importing more gas from Argentina's Vaca Muerta shale formation. But these efforts have yielded little progress so far (*p10*).

EDITORIAL

From Biden, with love

The direction that US policy will take under president-elect Donald Trump is far from clear, as he has to juggle diverse and conflicting pledges and interests

In his final days in office, President Joe Biden has further tightened US sanctions on Russian energy exports, with the toughest penalties in Washington's arsenal of financial pressure due to apply after 12 March.

The measures announced on 10 January would remove most carve-outs that have allowed Russia to continue exporting crude, refined products and LNG to global markets. They include sanctions announced by the State Department against entities involved in the production and export of LNG from Russia, which add to an already broad array of measures meant to curb Russia's current and future LNG export capacity. Washington has gradually expanded its list of sanctioned entities since February 2022, while at the same time granting periodic waivers to foreign buyers of Russian energy commodities — pushing back against calls from Kyiv and some eastern European allies to impose stringent sanctions against Russia, as it argued that cutting off Russian oil and gas exports would severely stress global energy markets and hurt western consumers. But those waivers will cease to apply on 12 March — unless the new administration of president-elect Donald Trump, who takes office on 20 January, decides otherwise.

While unstated, the escalation of sanctions has much to do with a looming and potentially radical change in US policy toward Russia and Ukraine. Biden administration officials appear to echo Trump's frequent invoking of the coming era of US "energy dominance" to make the case for fully enforcing existing sanctions against Russia. Those sanctions — coupled with Biden's orders to the Pentagon to increase supplies of military equipment to Ukraine in his last weeks in office — "provide the next administration a considerable boost to their and Ukraine's leverage, and [for] brokering a just and durable peace", a US official says. "It's our own energy abundance right now that is one of the enablers of this effort to penalise Russia for [Russian president Vladimir] Putin's actions in Ukraine," another US official says.

The Biden administration has further ramped up sanctions on Russian energy, in a bid to boost the US' and Ukraine's leverage in potential negotiations

But the direction of such a policy shift under Trump is still far from clear, as the president-elect has to juggle diverse and conflicting pledges and interests. Trump promised on the campaign trail to end Russia's war in Ukraine within 24 hours of taking office, but he now says that it would take up to six months to end the conflict. On the political side, the president-elect likely believes he can force Kyiv to accept territorial losses, but any idea that Putin might be ready for a mutually acceptable deal that guarantees Ukrainian security looks far-fetched, particularly given Russia's continuing advances on the battlefield.

And Trump's position on sanctions is far from clear. In Trump's first term, he disappointed Russian hopes that sanctions imposed after the annexation of Crimea in 2014 might be rolled back or softened. He lashed out against bipartisan congressional opposition to the now-defunct 55bn m^3/yr Nord Stream 2 pipeline, but subsequently took credit for those sanctions and criticised Biden for waiving them in 2021, while arguing that his administration would defend US exporters' interests.

On the other hand, some market participants expect that any peace negotiations with Ukraine might also address the possibility of an arrangement on gas supplies, and some EU members that are close to Moscow and have recently been deprived of cheap Russian gas supplies flowing through Ukraine are banking on this. But any arrangement that unleashes vast amounts of Russian gas, now largely stranded in Russia, does not chime with the commercial interests of the US oil and gas industry. Europe's straitened energy circumstances are probably quite welcome to Trump, who in his first term railed against European dependence on Russian gas while hawking US LNG as an alternative. The US has been a major beneficiary of Europe's search for alternatives to Russian energy since the EU banned Russian oil imports and Russia sharply reduced gas exports to the continent.

UKRAINE

Halt in Ukraine transit brings end to an era

The end to Ukrainian gas transit may have a larger impact on central and eastern Europe buyers than on Russia's gas revenue

The expiration of both the transit deal between Russia's Gazprom and Ukraine's Naftogaz and the interconnection agreement that underpinned it on 31 December has brought an end to a near 60-year era of Russian gas supplies to Europe through Ukraine. European customers — particularly those in central and eastern Europe — have been preparing for this for some time, but they still face higher procurement costs to replace the missing supplies. And for Russia, the change sees it lose one of the key tools it has relied on to keep allies in the region close.

Russian gas flows through Ukraine halted on 1 January as the agreements expired. Ukraine served as a crucial transit route for Russian gas for 57 years, since Austria's OMV began receiving flows in September 1968. Its role had waned over the past two decades, as Russia built alternative routes to bypass Ukraine — such as the 55bn m^3/yr Nord Stream, 33bn m^3/yr Yamal-Europe and 31.5bn m^3/yr Turkish Stream pipelines. Yet Gazprom still shipped 14.4bn m^3 through Ukraine last year. While a small part of the overall European mix, these supplies were still a vital source of supply for Slovakia, Austria, the Czech Republic and Moldova.

Replacing this lost gas will cost Gazprom's former buyers more money than they would have paid previously, mostly because of the additional transport costs they will now incur. Gazprom's long-term contracts generally specified delivery of gas to the receiving country's borders, covering most if not all transport costs. Former buyers will now need to book transport capacity across several countries to be able to receive supply from western Europe, in an environment where the cost of transport capacity has risen sharply over the past two years. Slovakia's SPP — the firm most affected by the loss of Russian gas, given the longer distance from alternative supply sources — expects its gas purchases to cost an additional €90mn ($93mn) this year. But despite the higher costs, security of supply in these countries does not appear to be at risk following the end of Russian supply, owing to the recent buildout of LNG import capacity and debottlenecking of the European gas network to allow stronger flows from west to east.

Yet some market participants in central and eastern Europe have questioned Ukraine's unwillingness to extend the transit contract, arguing that it does not reduce Russia's energy revenue because higher wholesale gas prices offset the drop in sales. The halt to Russian flows through Ukraine has increased TTF prices by €10-12/MWh, according to SPP's analysis, which some market participants argue would be sufficient to keep Russia's gas revenue stable. This analysis likely includes LNG exports from Russian independent Novatek's 17.44mn t/yr Yamal complex, which have continued to flow to Europe in recent months, and probably do not all yield revenue that is linked to TTF prices. A €10-12/MWh rise in TTF prices would not fully offset a drop in pipeline exports of around 450 GWh/d, meaning this would at the very least represent a reallocation of profits between Gazprom and Novatek, and add to Gazprom's profitability woes in the short-term.

Many of the countries that Russia supplied through Ukraine were pro-Russian allies

Collateral damage

In any event, Ukraine's decision was not driven solely by an attempt to curb Russia's energy revenue, which fuels its war effort. Ukraine was also motivated by political and strategic factors. Many of the countries that Russia supplied through Ukraine were pro-Russian allies — particularly Hungary, Slovakia and the breakaway Moldovan region of Transnistria. The loss of these supplies could hurt Russia not just from a financial standpoint but also from a geopolitical one.

The end of transit through Ukraine has triggered a major energy crisis in Transnistria, where Russia still has a military presence. Transnistrian authorities have heaped pressure on Moldova and Ukraine to allow transit to restart, while

UKRAINE

imposing rolling blackouts and cutting off most gas consumers, teetering on the edge of a humanitarian crisis. This also erodes the Transnistrian public's support for pro-European Moldova's government and pressures Ukraine to extend transit.

Slovakia has also been vocal in its opposition to Ukraine's decision to halt transit, threatening to cut off power exports and humanitarian aid, while Hungary has sent thinly veiled threats about blocking Ukraine's potential accession to the EU.

Slovakia has also been vocal in its opposition to Ukraine's decision to halt transit, while Hungary has sent thinly veiled threats

The public resistance these countries have performed in the past few months shows the extent to which Russia has made inroads through cheap energy, and consequently to what extent its influence in the region may recede if it remains unable to maintain such supplies. In the short-term, higher gas costs — such as the higher household tariffs imposed by Moldova's energy regulator — could stoke inflationary pressures and further compound anti-establishment and anti-western sentiment among the public.

Gazprom is able to maintain supplies to Hungary — as well as to a number of other countries where Russia retains political influence, such as North Macedonia, Bulgaria, Serbia and Bosnia and Herzegovina — through the Turkish Stream pipeline. But there is limited capacity to send additional supply to countries no longer receiving gas through Ukraine, given that Turkish Stream flows already averaged 471 GWh/d in 2024 out of the total capacity of 586 GWh/d available at Bulgaria's Strandzha 2/Malkoclar entry point from Turkey.

Even if more supply can reach Bulgaria, there are severe bottlenecks at the northern Serbian, Hungarian and Romanian borders that prevent a substantial increase in flows, making it difficult for Gazprom to get more gas to its former customers. This means the loss of these markets is likely to be long-lasting.

Flows reconfigure west-to-east

Central and eastern Europe markets had no alternative other than to turn west for additional supplies when they lost access to Russian gas from Ukraine, although they also tapped storage withdrawals to plug the gap.

Slovakia is the most affected country, owing to its role not only as an importer but also as a key transit country towards the Czech Republic and Austria. Exit flows at all of Slovakia's border points ceased from the beginning of January, with a flip to stronger withdrawals of 188 GWh/d on 1-11 January from 166 GWh/d in December. SPP has a significant volume of gas in storage, meaning it is likely Slovakia will mostly balance supply ad demand by ramping up withdrawals and importing gas from Hungary on an ad-hoc basis to optimise its portfolio.

Slovakia is the most affected country, owing to its role not only as an importer but also as a key transit country towards the Czech Republic and Austria

The Czech Republic turned towards much stronger imports from Germany after losing its supply from Slovakia, which had averaged 137 GWh/d in December. Imports from Germany at the Brandov virtual interconnection point jumped to 170 GWh/d on 1-12 January from 7 GWh/d in December. The abolition of the German storage levy at cross-border points, which had been €2.50/MWh in June-December, made German imports much more competitive after the turn of the year.

Similarly, Austria also turned to stronger imports from Germany to fill the gap left by Russian supplies. Imports from Slovakia averaged 231 GWh/d in December but have since fallen to zero on most days, while receipts at the Oberkappel entry point from Germany climbed to 115 GWh/d on 1-12 January from just 28 GWh/d in December. Withdrawals from storage provided additional flexibility, stepping up to 479 GWh/d on 1-11 January from 358 GWh/d in December.

Gas continues to flow uninterrupted to several of Gazprom's other buyers in southeastern Europe through Turkish Stream, with receipts at Strandzha 2/Malkoclar averaging 504 GWh/d on 1-13 January compared with 510 GWh/d over the whole of last month.

US

Trump 2.0 set to shake US gas market

The incoming president may struggle to make good on his promises to unleash US energy potential, writes David Haydon

President-elect Donald Trump will begin to unpick much of his predecessor's energy policies once he is sworn into office on 20 January, likely with profound consequences for the US gas market. But some of President Joe Biden's moves may prove difficult to reverse.

On the campaign trail, Trump pledged to unleash the country's energy potential, calling on the upstream sector to "drill, baby, drill" while promising to reduce regulation and increase access to acreage. To do this will partly hinge on passing legislation to increase federal oil and gas lease sales, which would undo key parts of Biden's Inflation Reduction Act and reverse the outgoing administration's recent withdrawal of more than 625mn acres (250mn hectares) of federal waters from oil and gas leasing, affecting the entirety of its Atlantic coastline, most of its Pacific coast, part of the northern Bering Sea and the eastern Gulf of Mexico.

Trump says he will overturn this most recent act as soon as he assumes office, but this may prove challenging. It was carried out under section 12(a) of the Outer Continental Shelf Lands Act — meaning Trump cannot undo it by executive order. It will instead require legislation to be passed through the now-Republican majority in US Congress. In any event, this may have limited impact on overall US gas production, which predominantly stems from onshore shale basins.

The gas market environment in the US may make it difficult for Trump to achieve his stated aim of boosting the US upstream sector's potential. Several large producers have opted to curtail their production in recent months, as the market became oversupplied. And gas prices at the country's benchmark Henry Hub reached an all-time low last year, despite a continued increase in power sector gas demand. Gross production reached a fresh record in 2024 at 113bn ft^3/d (1.2 trillion m^3/yr), but this was only marginally higher than the 2023 average of 112.8bn ft^3/d, the most recent figures from US agency the EIA show.

The US gas industry is pinning its hopes on a sharp increase in LNG export capacity expected this year, as well as a boost in power sector gas burn driven by data centres supporting artificial intelligence. As much as 28mn t/yr of additional LNG export capacity is slated to start up in the US this year, which would require around 3.83bn ft^3/d of additional feedgas, assuming 10pc liquefaction losses.

One of the first and easier moves for Trump may be to undo the Biden administration's pause on LNG export permits

Upstream production may fail to keep pace with the expected increase in gas demand from both the domestic and export markets, judging by market participants' price expectations. Oil and gas executives responding to a December 2024 survey by the Federal Reserve Bank of Dallas expect the Henry Hub spot price to average \$3.19/mn Btu by the end of 2025, and rise further to \$3.63/mn Btu in 2027 and \$4.16/mmBtu by 2029, according to the respondents.

Start with low-hanging fruit

One of the first and easier moves for Trump may be to undo the Biden administration's pause on LNG export permits to countries with which the US does not have a free-trade agreement — a crucial authorisation for prospective LNG exporters, given that only a handful of countries have free-trade agreements with the US.

The export licence pause was widely criticised by US oil and gas companies, and the decision was suspended by a federal judge less than six months after it was instigated. Yet no LNG export project has received a similar authorisation since then, as the administration appeared to implement a de facto pause while it appealed the federal judge order. Trump will likely resume approvals of LNG export terminals very early on after beginning his second term, according to analysts at investment bank Piper Sandler. LNG export growth should pick up in 2025 and continue for the next several years, according to Piper Sandler.

SOUTH KOREA

Seoul may scale down nuclear expansion plans

The delay to finalising the country's nuclear goals may make it unfeasible to build sufficient capacity before current assets expire, writes Evelyn Lee

South Korea's energy industry has faced a whirlwind of challenges since the impeachment of now-suspended president Yoon Suk-Yeol, with the political turmoil stalling a crucial review of its energy strategy in the national assembly. The government is now seeking to scale down its nuclear expansion ambitions in order to hasten the plan's review.

Yoon's surprise declaration of martial law last month was reversed within six hours owing to bipartisan political pressure and widespread protests, which resulted in a national assembly vote in favour of the president's impeachment and his subsequent arrest on 15 January. Yoon is suspended from office pending a ruling by the country's constitutional court — due within six months of the impeachment vote on 14 December. If six out of nine justices vote to uphold the impeachment, Yoon will be removed from office and presidential elections will be held within 60 days.

South Korea acted quickly following the martial law declaration, but government action has overall been slowed down by the political turmoil — including on energy policy. The latest draft of its long-overdue electricity plan was completed in June and scheduled to be submitted to the Trade, Industry, Energy, Small and Medium-sized Enterprises and Start-ups Committee of the national assembly by the end of last year. But the committee has suspended general meetings since 19 December, according to schedules released on its website.

The long-term electricity plan is renewed every two years and serves as a basis for business planning, especially for state-controlled companies

The long-term electricity plan is renewed every two years and serves as a basis for business planning, especially for state-controlled companies. Gas incumbent Kogas' procurement strategy has historically reflected the electricity plan. The latest draft lays out Seoul's intention to build three more nuclear reactors by 2038. But planning and construction would take nearly 14 years, according to the government, so the delay in finalising the plan could result in a power supply shortfall by 2038 — when 9.15GW of existing nuclear capacity is set to expire.

Nuclear fallout

The government may opt to scale down its nuclear expansion ambitions in order to get the draft electricity plan seen by the committee — which must review the plan, although it is not required to approve it. And less nuclear capacity could increase the need for more gas-fired capacity.

The energy ministry pledged on 8 January to finalise the plan by June, after which it will pass related bills including the power grid act, but it did not say how it intends to progress the plan in the national assembly. The Korean Nuclear Society (KNS) responded on 9 January, accusing the government of allegedly planning to revise its nuclear objectives so it can speed up the plan's progress. The government's intent to revise its nuclear goals "without any scientific basis" shows that the electricity plan is just a "political bargaining tool that can vary depending on political interests", the KNS said. This threatens the stability of the South Korean electricity market, it added. The ministry did not respond to *Argus*' request for comment.

The government's intent to revise its nuclear goals shows that the electricity plan is just a 'political bargaining tool that can vary depending on political interests'

But the alleged revision may not have been solely driven by political motives. Seoul may have missed the window of opportunity for approving new nuclear capacity in the timescale required, judging by the 14-year timeline for planning and construction. It remains unclear how the government would offset any reduction in its nuclear ambitions, but South Korea's slow grid development may leave little alternative other than boosting gas-fired capacity. Under the current draft electricity plan, gas-fired output would account for a 25.1pc (160.8TWh) share of total generation in 2030 and 11.1pc (78.1TWh) in 2038, up from 22.9pc (142.4TWh) and 9.3pc (62.3TWh), respectively, in the previous plan.

CHINA

Chinese gas demand growth may slow in 2025

Year-on-year growth in China's aggregate gas imports fell starkly in the second half of 2024, and the pace of growth could decrease further this year

Rapid growth in China's electronics and electric vehicle (EV) sectors is expected to boost the country's industrial gas demand this year, although total demand growth may slow compared with 2024.

State-controlled Sinopec expects China's natural gas consumption will hit 458bn m³ in 2025, up by about 6.6pc from 2024. This growth will be driven by stronger demand from manufacturers of electronic products and new energy vehicles — which include battery EVs, plug-in hybrids and fuel-cell vehicles. Demand across the industrial, commercial and power generation sectors is also set to rise, on the back of a projected 4.5-5pc increase in economic growth, Sinopec says. China's natural gas consumption is forecast to account for 9.2pc of the country's primary energy consumption in 2025.

Higher consumption will require stronger gas imports. China is expected to receive around 201.2bn-203.5bn m³ of gas in 2025, up from 185bn m³ in 2024, Sinopec says. And Sinopec projects domestic gas production to hit 260.6bn m³ in 2025, up by 4.5pc from 2024. This would put aggregate supply at around 462bn-464bn m³, up by 6.3-6.8pc on the year. Chinese supply totalled around 391.3bn m³ in January-November 2024, the most recent data from customs and statistics bureau NBS show, which was up by 9pc from the 359bn m³ recorded a year earlier. The difference between projected consumption and aggregate supply in Sinopec's forecasts suggests the firm expects 4bn-6bn m³ year-on-year growth in injection demand.

The slower demand growth expected this year is in line with weaker imports in the second half of last year, underpinned by reduced economic growth. Total gas consumption grew by 10pc on the year in January-June, and China's economy grew by 5pc over the period, according to Sinopec's interim report. This resulted in a 14pc year-on-year increase in aggregate gas and LNG imports over the first half of 2024, which is starkly higher than the 6pc growth posted during the second half of the year, customs data show. Total gas imports rose by 10pc to 132.5 mn t in 2024. Import data suggest that Chinese gas consumption was weaker during the second half of the year, which may continue into this year.

Weaker demand caps pipeline use

Growth in gas shipments along China's West-to-East Pipeline this winter suggests Chinese downstream gas demand has remained weaker in January, based on the most recent data. China's state-owned infrastructure operator PipeChina has now connected its West-to-East 2, 3 and 4 pipelines, sending gas from central Asia as well as domestic gas to eastern China (*see map*).

China's West-to-East pipeline system

The connected pipelines are delivering a total of 140mn m³/d at present, according to a government news outlet. This flow rate suggests that the new facility may be underutilised owing to lower demand.

The pipelines sent around 132mn m³/d over 9-18 February 2024, which was before Pipeline 4 came on stream. Peak flow during the period hit 147mn m³/d, after deducting West-to-East Pipeline 1 flows, which averaged 55mn m³/d. The 20bn m³/yr West-to-East Pipeline 1 connects mature Tarim oil field with Shanghai and destinations along the route. Tarim had little output growth in 2021-23, data show.

Part of the West-to-East Pipeline 4 started up in late September, adding 41mn m³/d to the system's working capacity. And flows along the fourth line increased to 45mn m³/d on 1 January, the local government says. But total demand along PipeChina's grid had already decreased by 30pc on the year in January-February 2024. As flow rates are similar this year, this suggests gas demand in the Chinese grid has been low this winter, even ahead of this year's lunar new year holiday.

AUSTRALIA

Asset swap consolidates Woodside, Chevron LNG plans

The move by Australia's leading LNG operators should make them more competitive as global supply grows, writes Tom Major

The decoupling of Western Australia (WA) state's two LNG giants, Chevron and Australian independent Woodside Energy, reflects moves by both firms to concentrate on backfilling existing export projects as efficiently as possible, particularly against the risk of lower global LNG prices later this decade.

Woodside and Chevron agreed last month to swap their respective stakes in Australia's two largest LNG export terminals — with Chevron handing to Woodside its 17pc non-operated share in the 14.4mn t/yr North West Shelf (NWS) LNG project, and receiving Woodside's 13pc stake in Chevron's 8.9mn t/yr Wheatstone LNG. Woodside faces declining throughputs at the 40-year-old NWS — Australia's oldest LNG export facility — so is keen to advance development of the offshore Browse fields — a contentious project that will require both fiscal discipline and political nous. Chevron is not a participant in Browse so posed a potential obstacle for Woodside and its NWS joint-venture partners, leading analysts to conclude the swap may have cleared the path for a gas processing deal at NWS.

NWS has secured state consent to run until 2070 but now needs federal approvals — which are unlikely to be obtained before Australia's May election. A final decision is critical for the 11.4mn t/yr Browse, which is expected to cost around $20bn. Parallels can be seen between Browse and the 8mn t/yr Scarborough project. Woodside acquired the petroleum arm of BHP in 2022, allowing it to receive Scarborough's remaining 26.5pc share at a time when BHP was seen to have investment priorities elsewhere. Woodside sanctioned the field just months later.

Chevron is also prioritising securing gas for its Australian LNG operations, with the Gorgon and Jansz-Io fields that feed the 15.6mn t/yr Gorgon LNG terminal fast depleting. Seven fields have been identified in the offshore Carnarvon basin, targeting first gas in 2028. Woodside will complete the four-well Julimar phase 3 project before the swap deal concludes, securing backfill for Chevron's eight-year-old, 8.9mn t/yr Wheatstone terminal. Chevron controls about a third of WA's LNG exports, and has earmarked $1bn for its Australian operations in 2025.

Woodside's chance of completing a deal on Browse appears high, but the ramifications for Australia's flatlining LNG exports could be significant if a deal fails

But Woodside and Chevron will need CO_2 solutions for their WA facilities, following a 2022 law requiring net zero Scope 1 emissions for new gas projects. Chevron is in the process of optimising its underperforming 4mn t/yr Gorgon carbon capture and storage (CCS) facility adjacent to Gorgon LNG. Woodside is planning a 3mn-4mn t/yr CCS for Browse, which was referred to Australia's federal environment department in late 2024. As part of the asset swap, Chevron has exited Woodside's planned 5mn t/yr Angel CCS project offshore northwest Australia.

Still Browsing

Offshore CCS has not been developed in Australia to date, with these projects considered complex and risky. But Chevron was awarded an offshore exploration block for possible CCS near Wheatstone in August, as the technology's appeal is growing among companies required to comply with Australian emissions laws.

Browse nears a pristine offshore reef and has sparked opposition from Australia's environmental movement. Plans have so far been rejected by the WA environmental regulator, according to local media. The regulator is due to publish its report and recommendations this year. If the asset swap is approved and proceeds as planned in 2026, Woodside will cement its control of NWS with its 50pc operated stake. Securing a processing agreement would be a further coup, as without this Woodside could face a hefty bill for decommissioning equipment while missing out on lucrative revenue from the more modern Wheatstone LNG. Woodside's chance of completing a deal on Browse appears high. But if it fails, the ramifications for Australia's flatlining LNG exports could be significant.

AUSTRALIA

Australia edges towards LNG imports in 2025

Limited storage capacity and no prospect of major new field developments in the near term mean Australia may have to turn to LNG, writes Tom Major

Australia — formerly the world's largest LNG exporter — is edging closer to having to import the fuel in 2025, after years of supply warnings. Anti-gas lobbying from environmental groups, new emissions laws, slumping exploration and rising costs have all been blamed for forecasts of production falling below demand.

Debate about the rationale and demand for LNG continues, with no buyers having signed term sales yet. But the recent purchase of the proposed 386 TJ/d (10.3mn m³/d) Outer Harbor LNG project has raised expectations that deals may occur in 2025, to alleviate winter shortfalls from 2026 onwards. Southern Australia's gas output will drop by 40pc from 1,260 TJ/d in 2024 to 740 TJ/d in 2028, according to forecasts by market operator Aemo. Four import projects are planned for Australia's southern coast, including domestic firm Squadron Energy's 2.4mn t/yr Port Kembla LNG import terminal in New South Wales (NSW). Commissioning of onshore facilities began in November and could cover NSW's entire winter demand of about 481 TJ/d, excluding gas-fired generation, when fully operational.

NSW is Australia's largest jurisdiction by population and currently gets most of its gas supply from the ExxonMobil-operated Gippsland basin joint venture. ExxonMobil closed one of its three Longford gas plants in Victoria last year, removing 400 TJ/d of domestic gas output and further accelerating supply concerns in neighbouring NSW. Limited storage capacity exists and no new major fields are under near-term development. But Australia is working to increase pipeline capacity to bring coal-bed methane from Queensland to the south. An expansion of pipeline operator APA's 440 TJ/d South West Queensland pipeline could be approved in early 2025, which would lift gas security and help prevent prices spiking. LNG imports cost up to 25pc more than pipeline gas — *Argus'* assessment for month-ahead spot deliveries to Victoria averaged A$12.46/GJ ($7.66/GJ) in 2024, while LNG averaged A$16.03/GJ over the same period, *Argus* calculations show.

On the export scene, Australian independent Santos will restart production at its 3.7mn t/yr Darwin LNG facility after it commissions the Barossa field in July-September 2025. The project has withstood significant legal challenges since 2023, with Santos promising an offshore carbon capture and storage facility to offset emissions later this decade. Other Australian terminals will produce steady volumes in 2025. Independent firm Woodside's North West Shelf project took a 2.5mn t/yr train off line in 2024, reducing its capacity to 14.4mn t/yr, but it is set to start processing about 1.5mn t/yr of onshore gas from domestic firm Beach Energy and Japanese trading company Mitsui's 250 TJ/d Waitsia plant from early 2025.

Gas projects remain unpopular in many communities, and anti-fossil fuel members of parliament could hold the balance of power in the next government

Energy election

Australia's federal election must take place by May, in what could be a referendum on the Labour government's renewables-led vision for Australia's grid.

Labour is pursuing a policy to abolish Coalition-era gas exploration grants, as it finds itself wedged between critics of further gas extraction and domestic gas shortfalls. Scarcity of supply may already be contributing to manufacturing sector weakness. Aemo expects 13GW of gas-fired power will be needed under Canberra's 2050 net zero target. But gas projects remain unpopular in many communities, and anti-fossil fuel members of parliament could hold the balance of power in the next government, polls show.

The opposition Coalition party insists Labour's plan for a 82pc renewable grid by 2030 will not be achieved, and says if elected it would reduce Australia's 2030 43pc emissions reduction target and persist with coal until nuclear generators are built. Either way, more gas will be needed in the short term as coal plants retire, suggesting a greater role for Australia's east coast LNG projects.

BRAZIL

Brazil eyes gas supply boost in 2025

The government's goal to reduce gas prices by 40pc hinge on its success in reducing flaring and reinjections, write Betina Moura and Antonio Peciccia

Brazil's government is confident that new infrastructure projects will open supply routes and increase natural gas supply to the domestic market. But recent initiatives have yielded little results so far, and consumers and government officials have diverging views on the impact these may have on market prices.

Domestic gas prices are expected to fall by up to 40pc in the coming years, mines and energy minister Alexandre Silveira says. The decrease will be driven by an anticipated surge in supply — particularly from state-controlled Petrobras, which has around 80pc of gas market share. But such projections have been met with considerable scepticism by consumers, particularly in light of the scant progress made under the current administration. Part of the forecast increase in gas supply was meant to come from higher output from domestic fields as a result of a government push to reduce flaring and reinjections into oil fields. And imports of Argentinian gas from Vaca Muerta's shale formation would lift supply further at a later date.

Silveira pledged to curb gas reinjections and flaring as soon as he took office in January 2023, but the government has so far been unable to reverse the trend. Flaring has generally remained low in recent years, but reinjections have continued to climb to fresh records every year since 2018, and were on course to rise even further last year. Reinjections averaged 82.8mn m^3/d in January-November, compared with 78.8mn m^3/d in the whole of 2023 and 68.6mn m^3/d in 2022, according to the latest data from hydrocarbons regulator ANP.

The steady increase was partly the result of higher gas production, with gross output also rising steadily since 2010. But reinjections have risen faster than overall output in recent years, accounting for as much as 54pc of total production in the first 11 months of 2024, up from 53pc a year earlier and 25pc in 2017 (*see graph*).

The government issued a decree in August that allows ANP to order producers to increase natural gas deliveries to the domestic market, instead of reinjecting it for enhanced oil recovery. And the commissioning of the long-anticipated Rota 3 pipeline in mid-September has provided a new route to the market. But there has not been a significant shift in reinjections since these developments, the most recent figures indicate. The pipeline is only able to operate at about half of its designed capacity of 21mn m^3/d at present, and it will only become fully operational once a yet-to-be-scheduled second processing module is inaugurated, along with two floating production, storage and offloading platforms that should come on line in 2025 and 2026.

Recent developments in infrastructure and increased import capabilities could diversify supply sources and make the market more competitive

Shale up

Imports from Argentina's Vaca Muerta shale formation may allow Brazil to boost supply to the domestic market, in turn lowering prices.

Brazil has historically depended on piped natural gas, receiving an average of 13.75mn m^3/d in 2024, down from 27.84mn m^3/d in 2010, according to ANP. But the recent developments in infrastructure and increased import capabilities could enable it to diversify supply its sources and make the market more competitive.

Argentina has approved contracts for 15.3mn m^3/d of exports to Brazil, which have different expiration dates in 2026. The gas could be delivered entirely through Bolivia once the Argentina-Bolivia pipeline reversal project is fully operational. The line allows Argentina to export 19mn m^3/d to Brazil, and there are plans under way to expand its capacity by a further 10mn m^3/d — which would match the capacity of the 30mn m^3/d Bolivia-Brazil pipeline. And some firms are planning to use an existing pipeline system that provides gas to a 640MW thermal power plant in Brazil's Rio Grande do Sul state. Bolivia has yet to set transport tariffs for the proposal, which is expected to be defined in 2025.

EUROPE

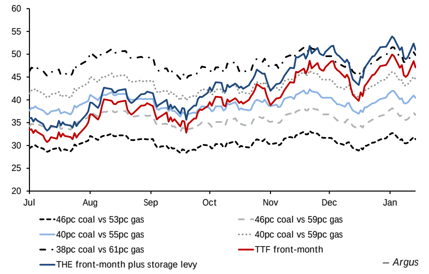
TTF gas price stays at top of coal-to-gas switching range

Utilities have been incentivised to run even the least efficient coal-fired plants ahead of the most modern gas-fired units since mid-November, writes Till Stehr

European gas prices have held at or near the top of the coal-to-gas fuel-switching range in recent weeks, even as outright prices remained highly volatile.

The Dutch TTF front-month contract has held high enough relative to coal and emissions allowance prices to incentivise utilities to run even the least efficient coal-fired plants ahead of the most modern gas-fired units since mid-November — despite volatile gas prices in recent weeks (*see graph*). Changing weather patterns and uncertainty over the future of Russian gas supply has exacerbated an already tight global gas market balance. The *Argus* TTF February contract fell by about 20pc in two weeks, from €48.45/MWh on 3 December to €40.02/MWh on 16 December. The contract rose again after Russian gas flows through Ukraine stopped on 1 January, but fell the following week after it became clear that the lost supply could be met through storage withdrawals. It closed at €47.10/MWh on 14 January.

Gas prices vs fuel-switch range €/MWh



Gas' position relative to coal in the merit order is a signal of the wider European gas market balance. If trading firms expect to have spare gas to burn, then gas prices fall low enough to outcompete coal in the power sector. If the market needs to conserve gas, then higher gas prices discourage strong gas burn in the power sector. But the progressing coal phase-out across much of Europe is narrowing the extent to which the power sector can play this buffering role. Many trading firms had already banked on strong coal burn this winter and trading activity was low in the shoulder season, market participants tell *Argus.*

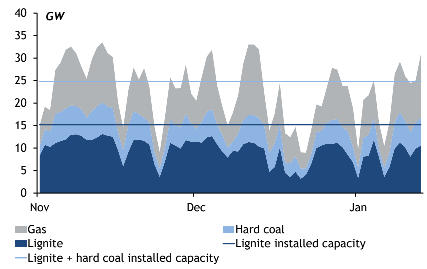
A mild start to winter and strong availability of LNG led to low storage withdrawals last year, pushing gas prices through the fuel-switching range in December. Even through a colder-than-average January, high stocks kept gas prices at the bottom of the fuel-switching range, incentivising strong gas burn in the first quarter.

In any case, renewables generation is a more significant driver of power sector gas burn than competition with other fossil fuels. And two sustained periods of low wind speeds and continuous cloud cover this winter so far have required European gas-fired generation to step up. A period of low wind speeds forecast for 16-23 January may again lift the call on gas-fired generation across Europe.

Gas-fired output remains high

In Germany, where remaining scope for coal-to-gas fuel switching in Europe is greatest, gas-fired output has stayed close to record highs in November, December and January so far, despite prices incentivising coal ahead of gas burn.

German thermal output vs capacity



German THE gas prices have been even further above coal-to-gas fuel-switching territory, considering their premium to the TTF and factoring in the German storage levy. The oldest operational coal-fired plants in Germany have an estimated efficiency of 38pc, while the most efficient gas-fired plant has a nameplate efficiency of 61pc. At prevailing prices since mid-November, even the least efficient German coal-fired plants were more profitable than the most efficient gas-fired units.

But gas-fired generation is still exceptionally high in Germany, at 9.1GW on 1-14 January, up from 8.5GW in December and 8.9GW in November. Gas-fired generation has had to step up at times of weak renewables generation, because the country's remaining lignite and coal-fired capacity is not enough to meet all residual demand. Combined generation from fossil fuels was higher than the 25GW of remaining lignite and hard coal-fired capacity on almost half of the days in November, December and January so far. And the 1.05GW Neurath F lignite-fired plant has been off line since 23 December, constraining lignite capacity further. About 2GW of gas-fired power stations produce at every hour independent of power price signals, but the remaining gas-fired plants have been priced in during times of high demand and low renewables output because of extremely high power prices in Germany.

IN BRIEF

EU does not plan to extend gas price cap beyond January

The European Commission says it is not considering extending its dynamic gas price cap mechanism at present. The commission proposed a price cap on wholesale prices in a "specific context" and this remains an emergency measure intended to be in place for a "limited period of time". Prolonging the measure could prove legally complex in this context. The cap would be triggered under existing regulation only if the Dutch TTF front-month price on the Ice Endex exchange settles higher than €180/MWh ($185/MWh) for three consecutive days and is €35/MWh above a reference price basket incorporating global gas and LNG prices.

Belgium approves decree on Russian LNG re-export ban

Belgium's council of ministers has approved a draft royal decree outlining measures to restrict the transshipment of Russian LNG to non-EU countries. The draft decree provides control mechanisms and obligations ensuring compliance with the European Commission's sanctions prohibiting the transshipment of Russian LNG to third-party countries, which takes effect on 25 March. EU members are prohibited from supplying reloading services enabling the transshipment of LNG originating in or exported from Russia, according to the commission's sanctions.

Biden bans oil, gas leasing in Atlantic, Pacific

President Joe Biden has withdrawn more than 625mn acres (250mn hectares) of federal waters from oil and gas leasing indefinitely, seeking to block offshore producers from expanding beyond their existing footprint in the US Gulf of Mexico. The move will affect all of the US' Atlantic coast, most of its Pacific coast, part of the northern Bering Sea and the eastern Gulf of Mexico. Such an action cannot be reversed easily, which could frustrate any unilateral bid by president-elect Donald Trump to open the areas to drilling. Biden cited the risks of climate change and a repeat of the 2010 Deepwater Horizon oil spill as the basis for his decision.

First gas starts at Greater Tortue Ahmeyim LNG terminal

First gas has begun to flow to the planned 2.3mn t/yr Greater Tortue Ahmeyim liquefaction terminal's floating production storage and offloading (FPSO) unit — the 2.7mn t/yr *Gimi* —offshore Senegal and Mauritania, project developer BP says. This puts the project another step closer to commissioning. The first cargo from the terminal is expected in the first quarter of this year, project partner Kosmos Energy says.

PipeChina begins expanding Yangpu LNG terminal

China's state-owned infrastructure firm PipeChina has started building the second phase of its Yangpu LNG terminal in south China's Hainan province, the firm says. The second phase will add three 220,000m³ LNG storage tanks, raising natural gas storage capacity by 400mn m³. The terminal mainly supplies gas to customers in Hainan, as well as to nearby Guangdong and Guangxi provinces.

India's H-Energy seeks FSRU

India's privately owned H-Energy has issued a request for a floating storage and regasification unit (FSRU) to be delivered to Jaigarh, Maharashtra in October 2025-February 2026, several sources tell *Argus*. The unit is required to have a minimum capacity of 137,500m³, with a preference for units with 145,000m³ of capacity and above. It should be operational for a period of 10-15 years, the sources say. The requested FSRU could regasify up to 6mn t/yr of LNG and would be India's first functioning FSRU.

GLOBAL GAS MARKET OVERVIEW

KEY PRICE MOVEMENTS

- The TTF February contract edged lower to $14.51/mn Btu on 13 January from $14.58/mn Btu on 30 December
- The Argus Northeast Asia (ANEA) des LNG price for front half-month delivery decreased to $13.47/mn Btu from $14.62/mn Btu over the same time frame
- The Nymex February contract for delivery at the Henry Hub remained flat compared with a fortnight earlier, at $3.93/mn Btu
- The Argus Round Voyage charter rate for the US Gulf coast-Northwest Europe route (ARV2) remained unchanged at $14,000/d

European premium spurs LNG diversions from Asia

Tighter gas supply after Russian flows to Europe dropped on 1 January supported Europe's price premium over northeast Asia, prompting at least five LNG cargoes to be diverted towards Europe from Asia in the first half of this month.

Russian gas flows through Ukraine halted at the start of the year after the transit contract and interconnection agreement that made it possible to use that transport route expired. Dutch TTF prompt and near-curve prices have firmed since then, with the TTF front-month contract reaching €49.75/MWh on 2 January, the highest since 16 October 2023. The impact of the Russian gas transit halt has eased since the start of the month and European gas prices largely trended lower over the fortnight to 13 January, although prices are still elevated compared with the northeast Asian market, where mild weather has sapped demand.

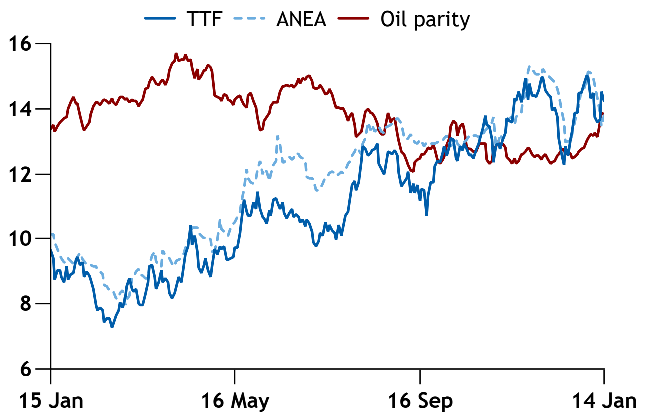
A series of cold snaps across much of Europe during the first half of January limited the price decrease. But weaker Asian demand has meant that European buyers have not needed to bid as high for LNG cargoes to attract Atlantic basin cargoes. Northwest European front-month LNG delivered prices fell by 9¢/mn Btu to $14.265/mn Btu over the fortnight to 13 January. But northeast Asian delivered prices dropped more significantly, by $1.06/mn Btu to $13.45/mn Btu over the same period, with many buyers staying out of the spot market.

Stronger price decreases in Asia resulted in the northwest European market offering a higher return for uncommitted Atlantic basin cargoes than northeast Asian delivered markets, after subtracting charter costs. The *Argus* Northeast Asia des price for March was assessed on 10 January at a 33¢/mn Btu premium to the northwest Europe des price for February, which was not enough to cover the 69¢/mn Btu difference in charter costs when shipping to South Korea's Incheon rather than the UK's Milford Haven, based on the prompt rates for tri-fuel diesel-electric (TFDE) carriers.

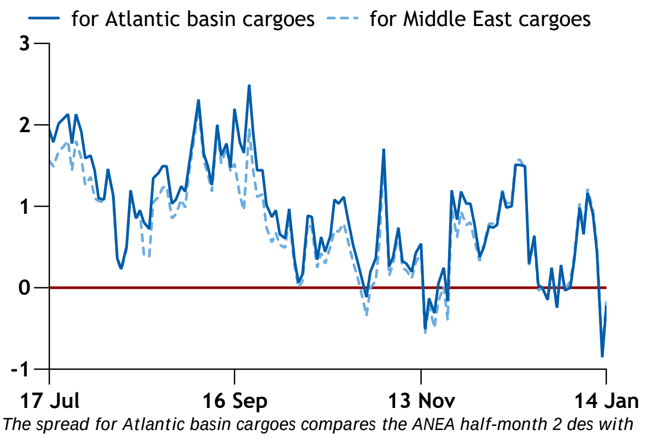
Five LNG carriers — the 180,000m³ *Bushu Maru*, 177,000m³ *Grace Dahlia*, 162,000m³ *Maran Gas Sparta*, 174,000m³ *Diamond Gas Crystal* and same-sized *Flex Vigilant* — have switched course to Europe since 8 January, having previously been sailing towards the Cape of Good Hope, ship-tracking data from Vortexa show.

Spot charter rates for TFDE vessels in both the Atlantic and Pacific basins have remained unchanged since the start of the year however, with Atlantic rates holding a $500/d premium to Pacific rates. Newbuild additions from South Korean and Chinese shipyards have mostly stayed in the Pacific basin for their first voyages, supporting Pacific supply relative to Atlantic, and in turn weighing on Pacific rates relative to Atlantic rates.

TTF, ANEA vs oil parity *$/mn Btu*



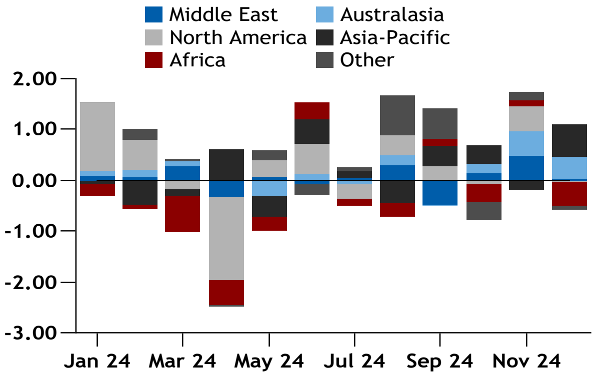
ANEA vs NW Europe LNG des arbitrage *$/mn Btu*



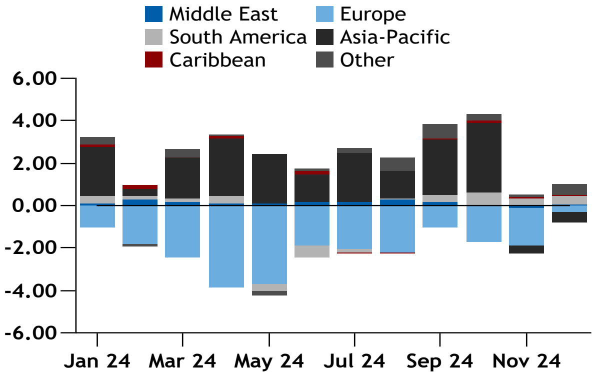
The spread for Atlantic basin cargoes compares the ANEA half-month 2 des with NW Europe half-month 1 des. The spread for Middle East cargoes compares both prices for the same delivery period, half-month 1

LNG TRADE FLOWS

LNG exports, yoy change *mn t*



LNG imports by region, yoy change *mn t*



Global LNG imports fall in December

Global LNG imports in December were the highest for any month of the year, at 37.8mn t, but that was still lower than the 39.1mn t imported globally in December 2023, according to data from monitoring firm Kpler.

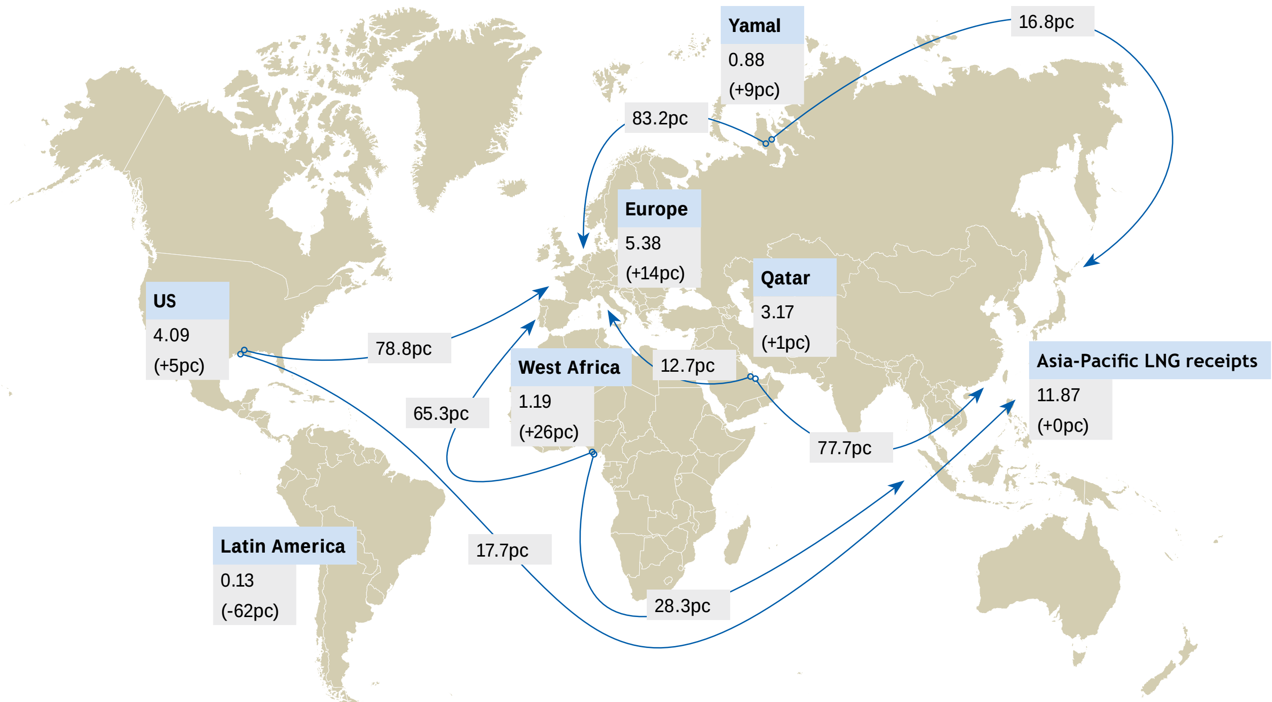
Northeast Asian and European imports both followed this trend — higher on the month but lower than in the same period a year earlier. Asian imports fell by 3.8pc to 25.6mn t from 26.6mn t in December 2023, while European imports dipped by 13.3pc to 10.9mn t from 11.8mn t a year earlier.

A steep contango in delivered prices over the fourth quarter of 2023 incentivised the use of LNG tankers as floating storage in December 2023, which may have contributed to the concentration of deliveries in December. The absence of a similar price structure in December 2024 incentivised earlier deliveries, particularly given some early winter cold snaps.

European imports fell despite firmer demand, which was supported by lower minimum temperatures in northwest Europe. Daily lows in Germany's Essen averaged 2.5°C in December, down from 4.2°C a year earlier. Demand was also supported by overcast and still conditions that reduced wind and solar power output. By contrast, Asian demand may have been weighed down by milder weather in northeast China, with daily lows in Beijing averaging minus 4.5°C in December 2024, compared with minus 7.7°C in December 2023.

Milder weather may have also dented import demand in South Korea, which recorded its largest year-on-year drop in December, with deliveries falling by more than 820,000t.

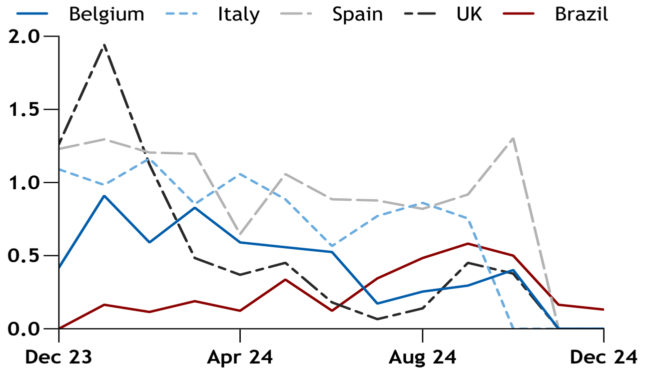
Latest estimated gas imports and exports *mn t*



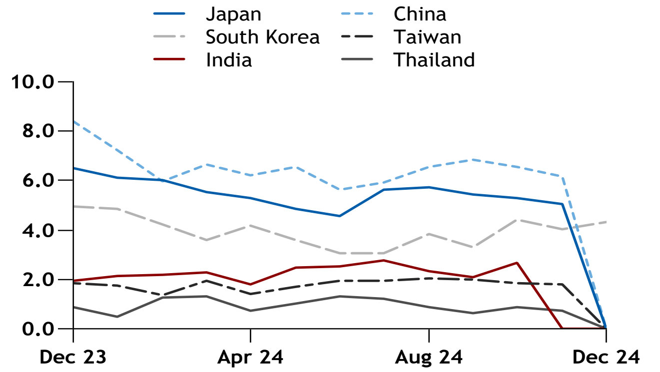
± change represents past two weeks vs previous two weeks

LNG TRADE FLOWS

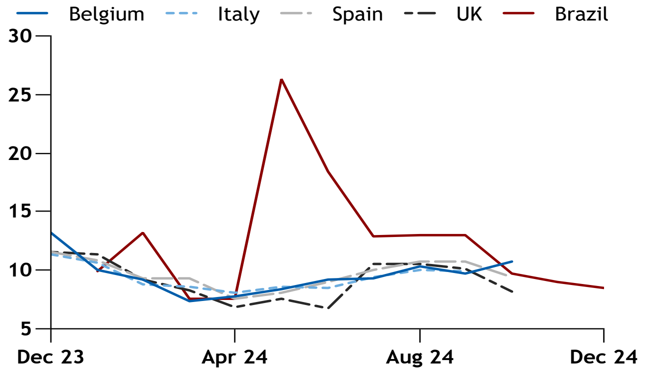
Atlantic basin LNG import volumes (customs data) *mn t*



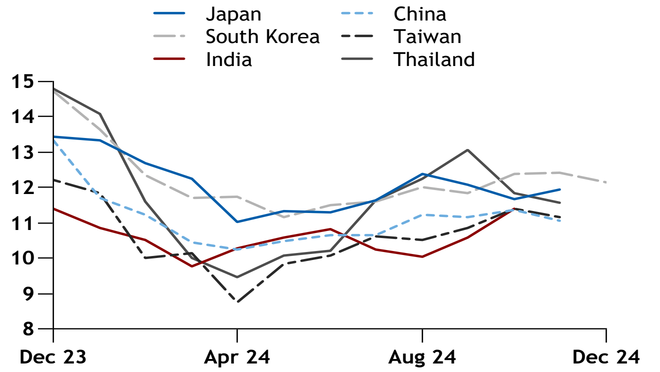
Asia-Pacific LNG import volumes (customs data) *mn t*



Atlantic basin LNG import prices (customs data) *$/mn Btu*



Asia-Pacific LNG import prices (customs data) *$/mn Btu*



Declared LNG import volumes *'000t*

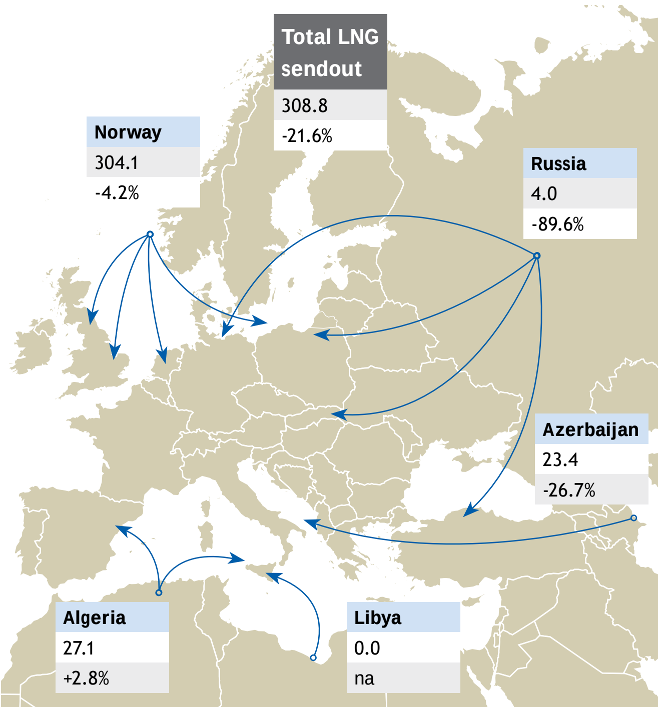
Importer	Jul	Aug	Sep	Oct	Nov	Dec
Northeast Asia						
China	5,899	6,537	6,837	6,554	6,149	0
Japan	5,621	5,729	5,430	5,292	5,050	0
South Korea	3,041	3,854	3,279	4,411	4,005	4,297
Taiwan	1,962	2,027	1,993	1,841	1,803	0
South and southeast Asia						
India	2,784	2,306	2,103	2,668	0	0
Pakistan	554	737	553	541	609	668
Bangladesh	0	0	0	0	0	0
Thailand	1,206	890	643	857	725	0
Europe						
UK	64	140	454	379	0	0
Netherlands	926	1,042	1,032	962	0	0
Belgium	173	256	294	403	0	0
Germany	303	348	289	433	0	0
Poland	0	0	0	0	0	0
Lithuania	0	0	0	0	0	0
France	0	0	0	0	0	0
Spain	877	820	916	1,300	0	0
Portugal	298	345	259	275	0	0
Italy	772	861	755	0	0	0
Croatia	185	179	192	132	0	0
Greece	98	21	21	197	0	0
Turkey	0	0	0	0	0	0
Latin America						
Brazil	346	484	582	497	168	127
Argentina	368	248	0	42	0	0
Chile	321	143	131	222	22	0

Declared LNG import prices *$/mn Btu*

Importer	Jul	Aug	Sep	Oct	Nov	Dec
Northeast Asia						
China	10.64	11.23	11.16	11.36	11.07	
Japan	11.65	12.40	12.08	11.65	11.94	
South Korea	11.61	12.00	11.84	12.38	12.42	12.14
Taiwan	10.61	10.53	10.85	11.40	11.16	
South and southeast Asia						
India	10.24	10.04	10.60	11.38		
Pakistan	10.19	10.15	9.69	9.85	9.34	9.00
Bangladesh						
Thailand	11.64	12.26	13.05	11.85	11.58	
Europe						
UK	10.54	10.51	10.07	8.15		
Netherlands	11.68	11.49	12.60	12.97		
Belgium	9.26	10.34	9.74	10.69		
Germany	10.53	10.55	9.86	11.94		
Poland						
Lithuania						
France						
Spain	9.99	10.71	10.77	9.39		
Portugal	8.17	7.45	8.49	8.54		
Italy	9.41	10.04	9.88			
Croatia	10.49	10.37	11.31	11.50		
Greece	10.57	10.33	11.24	10.89		
Turkey						
Latin America						
Brazil	12.87	13.04	12.99	9.71	8.96	8.51
Argentina	11.62	11.44		13.60		
Chile	7.19	6.35	5.50	6.85	6.37	

EUROPE

Supplies from key routes (month to date) *mn m³/d*



Stockdraw surges at the start of 2025

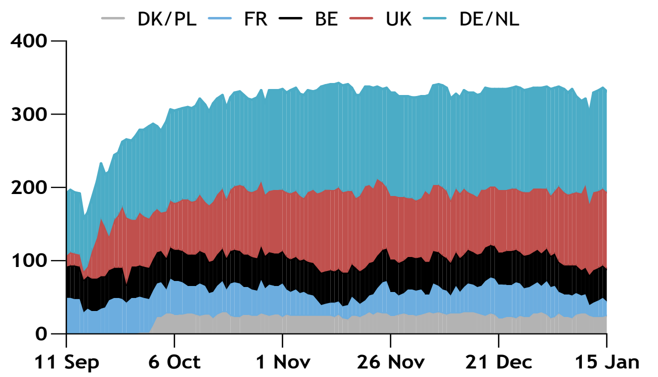
Stronger heating demand and the need to compensate for lost Russian supply led European firms to ramp up storage withdrawals in the first two weeks of January.

Withdrawals from European underground storage sites averaged 6.3 TWh/d on 1-14 January, according to GIE transparency data. Stockdraw was particularly strong on 10-14 January, at 7.6 GWh/d. EU stocks have depleted quickly, falling to 746TWh — 65pc capacity — on the morning of 14 January, from 824TWh, or 72pc full, on 1 January.

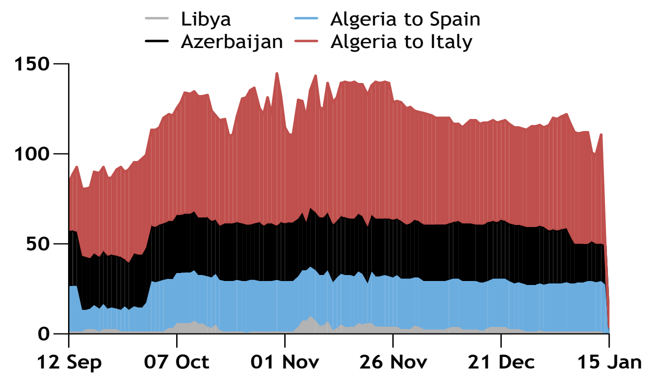
The strong stockdraw was largely driven by high German withdrawals. Net withdrawals from German gas storage sites doubled from 1.2 TWh/d in the first week of January to 2.4 TWh/d on 8-14 January. But withdrawals were slower than a year earlier, and well below winter 2020-21.

Hefty stockdraw in Germany largely reflected stronger demand from central and eastern European countries affected by the halt of Russian transit gas from 1 January. Germany's combined exports to Austria and the Czech Republic surged to nearly 300 GWh/d over 1-14 January, up from 48 GWh/d in all of December and 250 GWh/d on the same dates last year. The abolition of Germany's storage levy on gas exiting its grid on 1 January also aided the surge in exports.

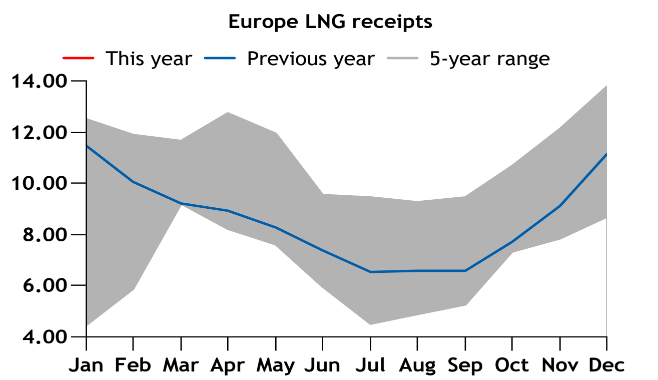
Norway pipeline supply to EU *mn m³/d*



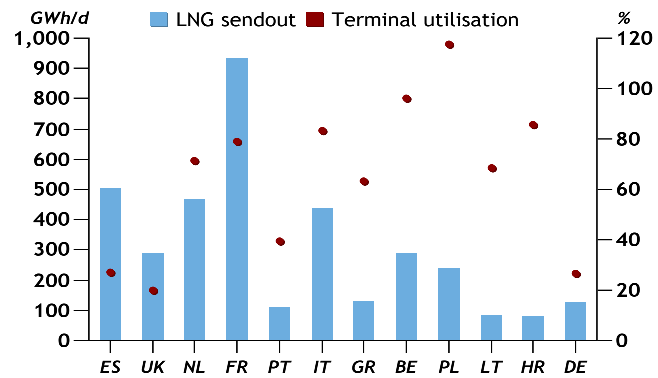
Supply to EU from southern routes *mn m³/d*



Europe LNG seasonality chart *mn t*



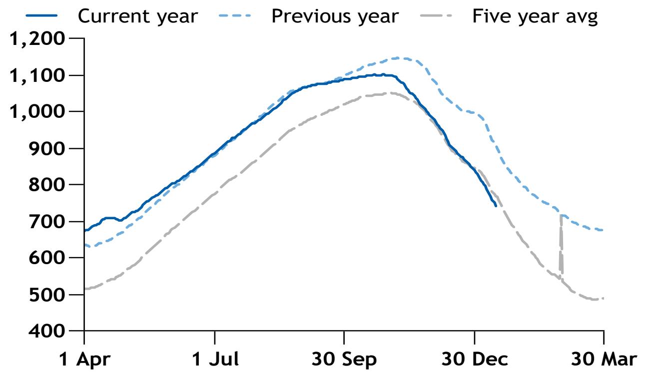
LNG sendout and terminal utilisation



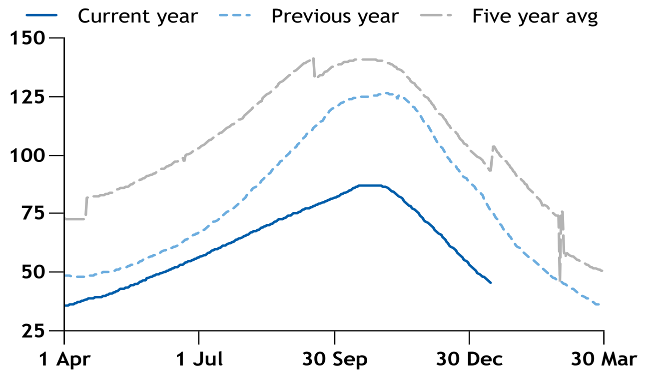
In the first half of the month the graph will show the figures for the full previous month, whereas in the second half of the month the graph will show month-to-date figures

EUROPE

Total EU + UK gas stocks *TWh*



Ukraine stocks *TWh*



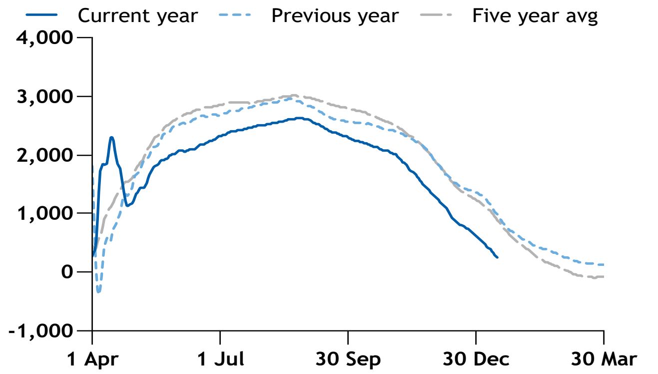
Countries in central and eastern Europe have also relied on stocks from their own underground reserves to compensate for lost Russian supply. Austria withdrew 495 GWh/d on 1-14 January, from 155 GWh/d over the period in 2023-24. Stockdraw in the Czech Republic averaged 200 GWh/d on those dates, up from 115 GWh/d in the previous two years.

In northwest Europe, stronger gas demand in the UK pushed NBP prompt prices far above the Peg and ZTP, encouraging firms to direct more Norwegian gas to the UK instead of the EU. Reduced Norwegian supply prompted French firms to increase storage withdrawals to meet strong domestic consumption and demand for exports. The French stockdraw rose to 1.1 TWh/d on 8-14 January from 770 GWh/d in the first week of the month. Meanwhile, exports to Belgium at the Virtualys point more than doubled on the week, and flows at Oltingue rose significantly.

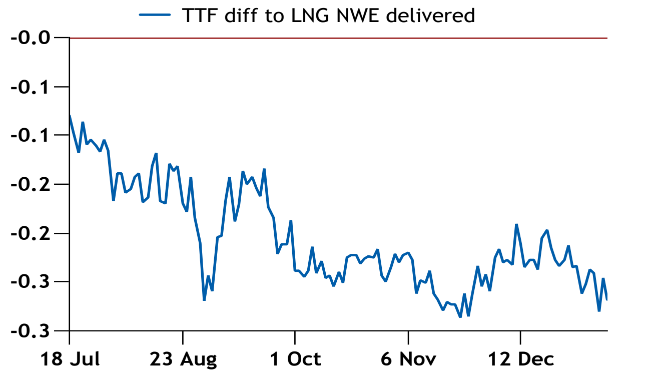
Further south, a partial outage at Azerbaijan's Shakh Deniz field on 7 January has weighed on Italy's gas receipts along the Trans Adriatic Pipeline. Works are scheduled to end on 19 January, and Italian gas demand is expected to remain strong while the works are ongoing.

Looking forward, stronger LNG deliveries could slow the stockdraw over the remainder of the month. High European prices and muted Asian demand have prompted several LNG carriers to divert away from Asia and head towards Europe. But forecasts for colder weather across the region in the third full week of January should keep gas demand firm.

EU + UK storage movements *GWh/d*

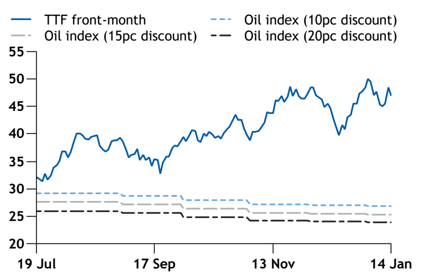


NW Europe LNG des-TTF spread *$/mn Btu*



Aggregate EU, UK and Ukraine inventories and storage movements					*TWh*
Month	**Initial stocks**	**% of capacity**	**Net withdrawals (injections)**	**1 year earlier**	**5-year average**
Aug 24	1,041	71.0	-3,057.6	1,064	1,394.0
Sep 24	1,140	77.3	-970.9	1,166	1,392.3
Oct 24	1,170	79.2	-517.0	1,219	1,389.9
Nov 24	1,186	80.3	3,807.6	1,268	1,386.4
Dec 24	1,054	71.4	5,343.8	1,202	1,382.0
Jan 25	882	59.7	3,103.6	1,080	1,375.2

TTF vs oil-linked LT contracts *€/MWh*

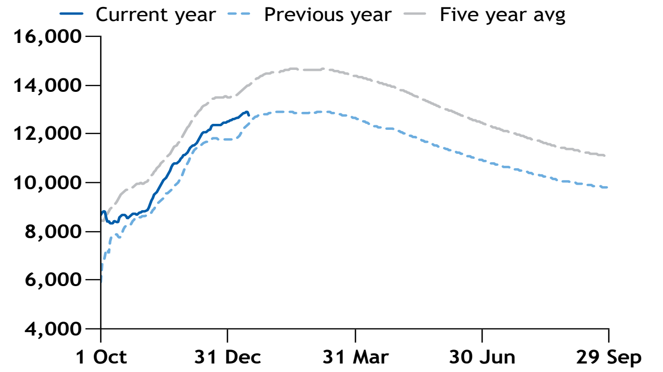


EUROPE

European demand by country, month to date *GWh/d*

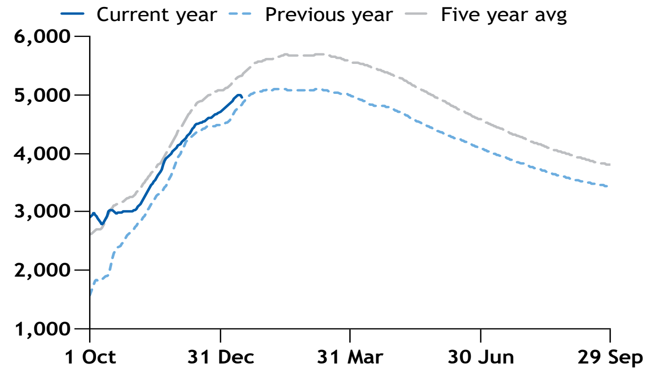
	Belgium	France	Germany	Italy	Netherlands	Poland	Portugal	Spain	UK	Total
Local distribution	462.4	1,237.2	2,038.6	1,568.6	770.6	624.2	58.2	na	2,505.6	**9,265.5**
Industrial	126.9	349.3	na	282.5	na	160.0	26.9	na	62.1	**1,007.7**
Power sector	73.4	69.1	na	605.0	na	na	33.0	190.4	613.1	**1,584.0**
Total consumption	**662.7**	**3,359.7**	**3,910.8**	**4,912.2**	**1,203.6**	**784.2**	**118.2**	**1,235.9**	**3,180.8**	**19,368.0**
±% year earlier	**-2.5**	**-4.3**	**0.9**	**-6.4**	**-5.2**	**-3.0**	**-8.9**	**-10.7**	**12.2**	**-1.9**

Aggregate demand *GWh/d*



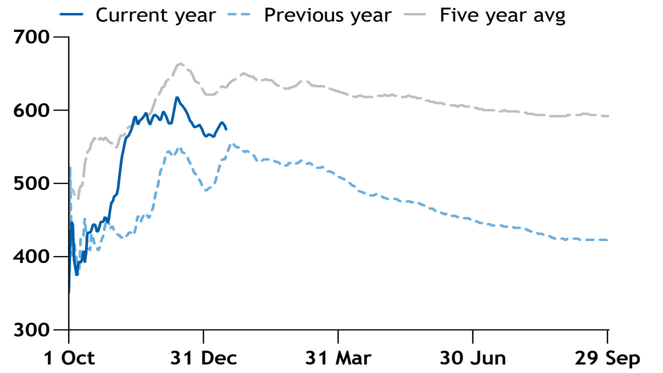
includes data on Spain, UK, Netherlands, France, Portugal, Italy, Poland, Germany, Romania, Hungary, Czech Republic, Belgium, Bulgaria, Croatia

LDZ demand *GWh/d*



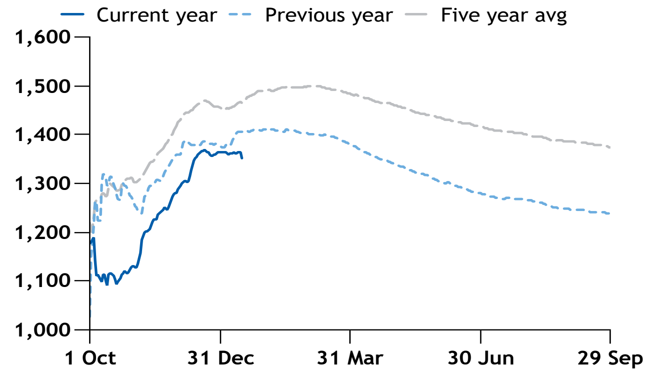
includes data on UK, Netherlands, France, Portugal, Italy, Poland, Germany, Romania, Belgium, Hungary

Power sector gas demand *GWh/d*



includes data on Spain, UK, France, Portugal, Italy, Belgium

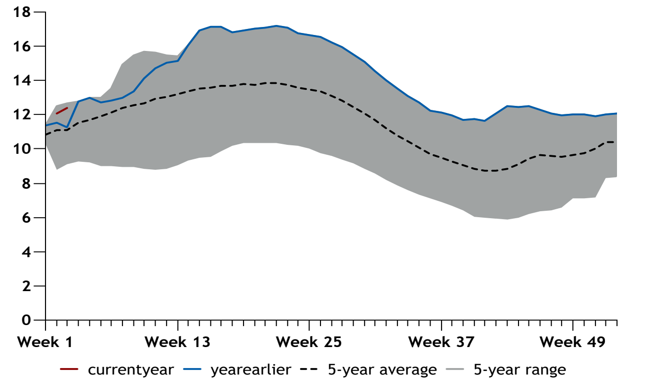
Industrial demand *GWh/d*



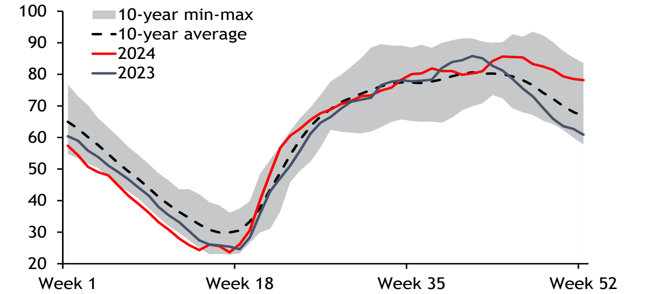
includes data on UK, France, Italy, Portugal, Belgium, Poland

Click here to download European gas demand data

Spanish hydroelectric stocks *TWh*



Nordic hydroelectric stocks *GWh*



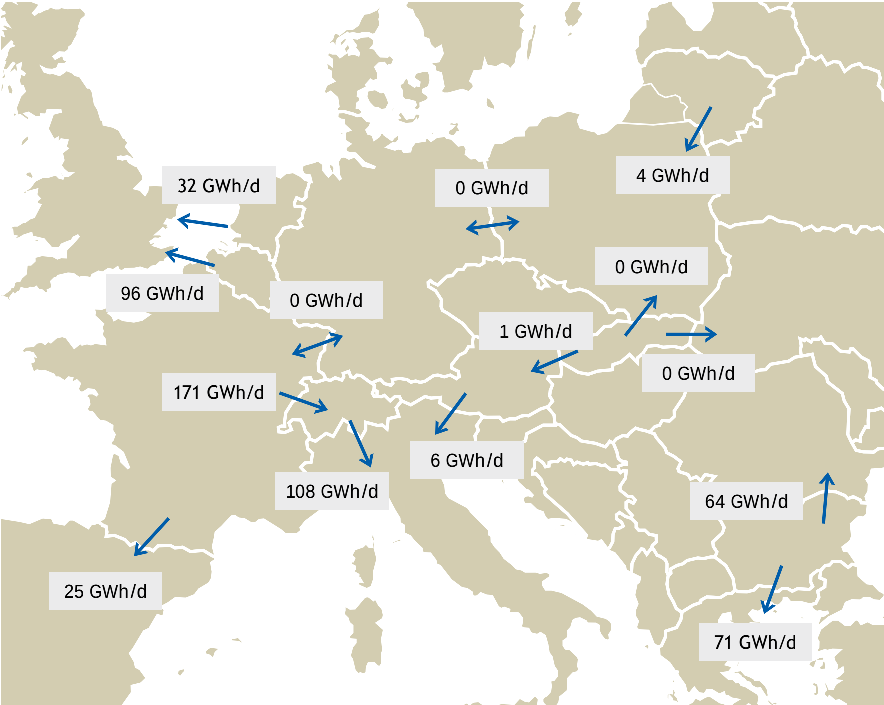
— Nord Pool

EUROPE

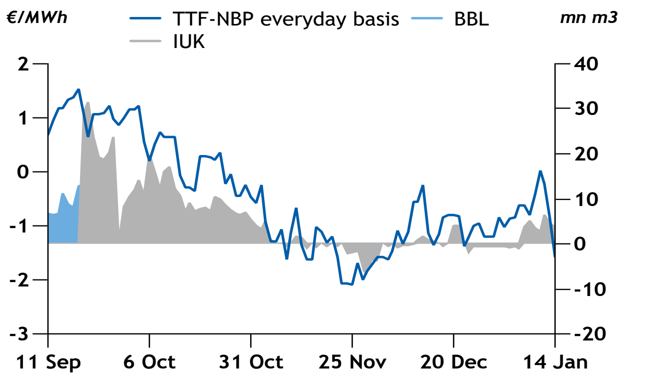
HIGHLIGHTS

- Italian, Greek and Bulgarian offtake from the Trans Adriatic Pipeline (Tap) has fallen since 7 January, when unplanned Azeri upstream works began
- Austria and Czech Republic have boosted imports from Germany to compensate for lost Russian supply
- French exports at the Virtualys and Oltingue points rose significantly on the week during 7-13 January, although they net imported at the Pirineos point on 12 January
- High UK demand has diverted Norwegian supply away from the EU. Supply from the UK to the continent has also waned during then

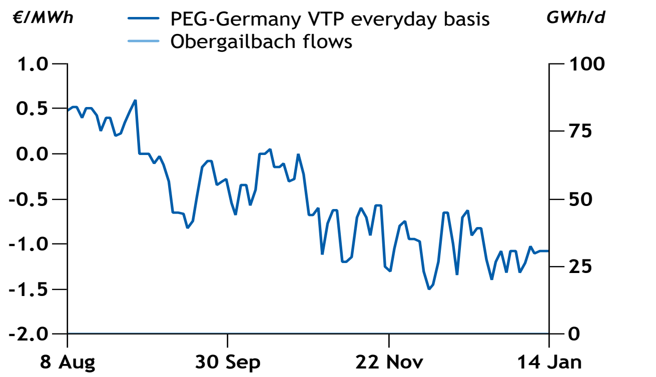
Cross-border flows (month to date)



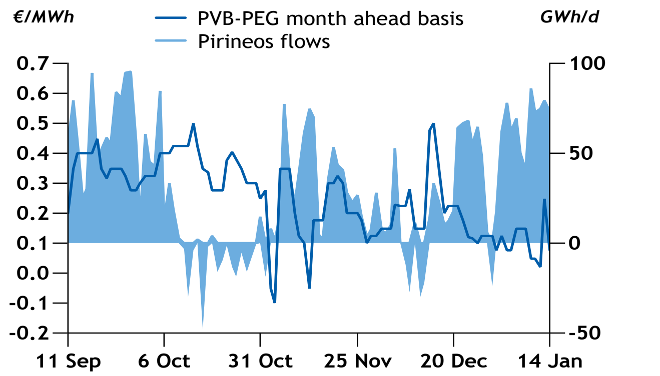
UK-EU gas flows *mn m³*



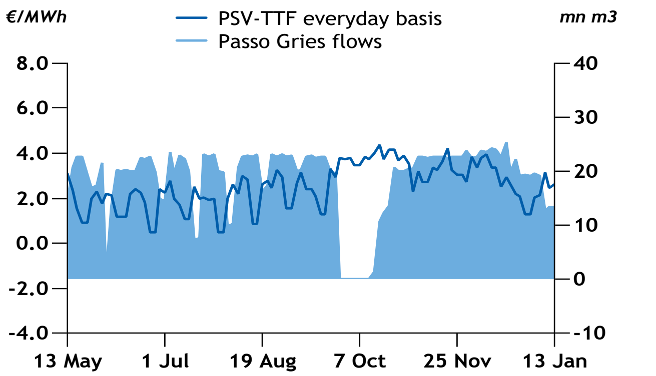
Germany-France gas flows *GWh/d*



France-Spain gas flows *GWh/d*



Switzerland-Italy gas flows *mn m³*



ASIA-PACIFIC

LNG deliveries to Asia-Pacific *mn t*

LNG stocks rise at Japan's power utilities

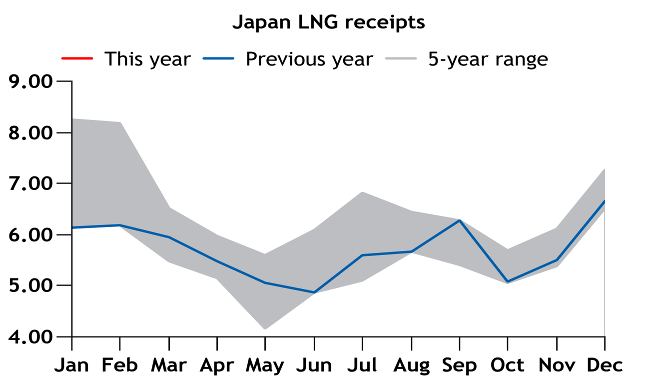
LNG inventories held by Japan's main power utilities increased in the second week of the year, despite a recovery in electricity demand. The utilities held 2.11mn t of LNG as of 12 January, up by 13pc from the previous week, according to a weekly survey by the country's energy ministry. Stocks were 1.9pc lower than the 2.15mn t held at the end of January 2024 but 7.7pc higher compared with the five preceding years' end-of-January stocks average.

Japan's total power demand averaged 116GW during the week to 12 January, up by 31pc from the previous week, according to nationwide transmission system operator Occto. Output from gas-fired power generation units surged over the week. Japan's gas-fired output averaged 43GW during the week to 12 January, up by 44pc from a week earlier, data from Occto show.

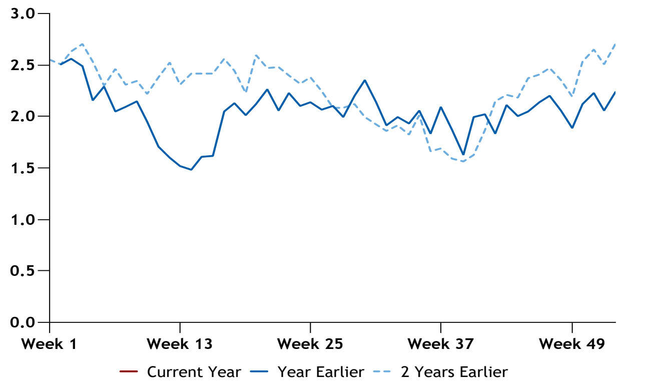
The week-on-week increase in demand was largely because of a rebound from slower demand a week earlier, as most factories in the country were closed the during new year holiday period.

Stronger power demand and higher gas-fired generation should have resulted in higher LNG burn over the week to 12 January. But the increase in LNG stocks implies that utilities received more LNG than they used last week.

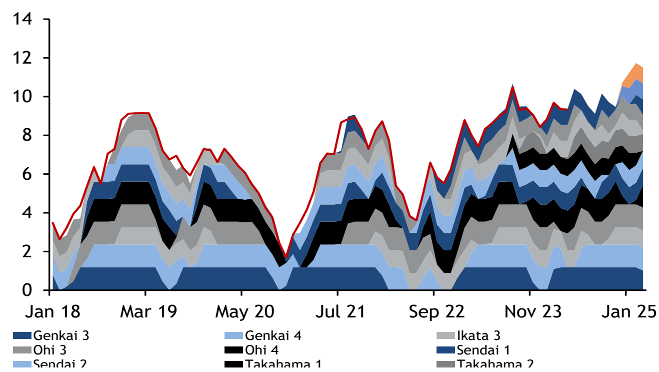
Japan seasonality chart *mn t*



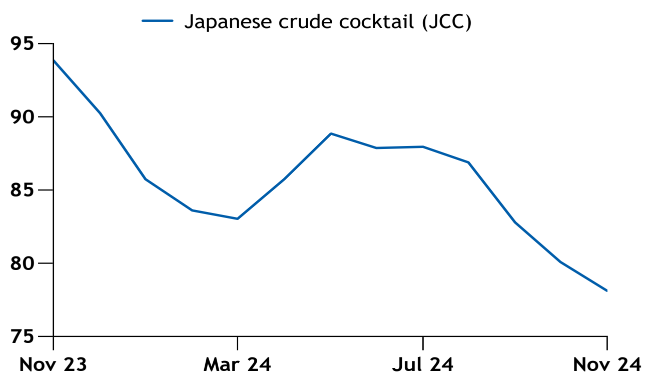
Japanese LNG stocks *mn t*



Japan nuclear availability *GW*

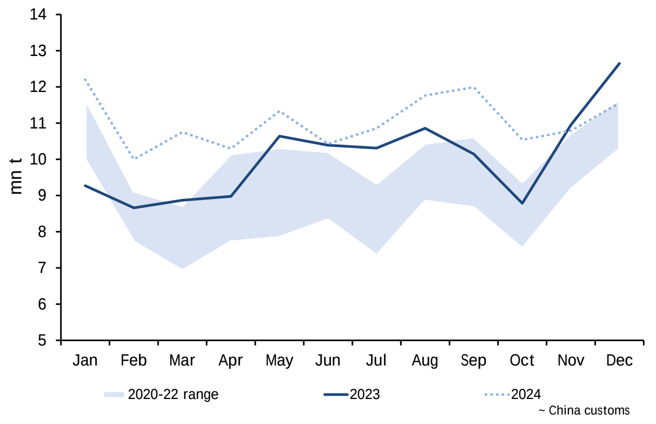


Japanese Crude Cocktail (JCC) *$/bl*



ASIA-PACIFIC

Chinese aggregate gas imports 2024 *mn t*



Click here to download data on Chinese domestic production, pipeline imports and LNG receipts

China's imports fall on year in December

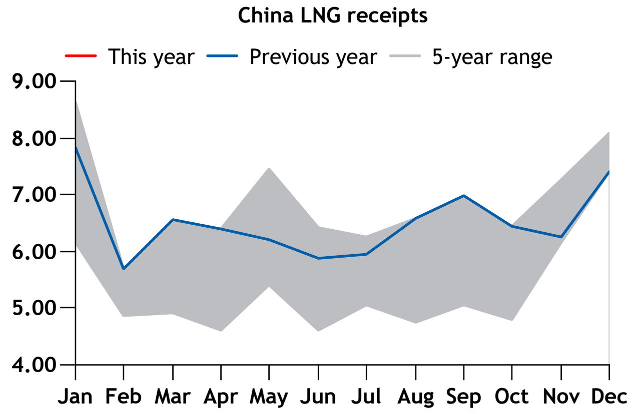
Aggregate LNG and pipeline gas imports to China fell to 11.6mn t in December from 12.6mn t a year earlier, Chinese customs data show.

The drop was likely driven by weaker overall gas demand, the most recent data suggest. LNG imports fell by about 500,000t, according to preliminary data from ship-tracking firm Vortexa, which implies that half of the import shortfall was owing to a drop in pipeline imports too.

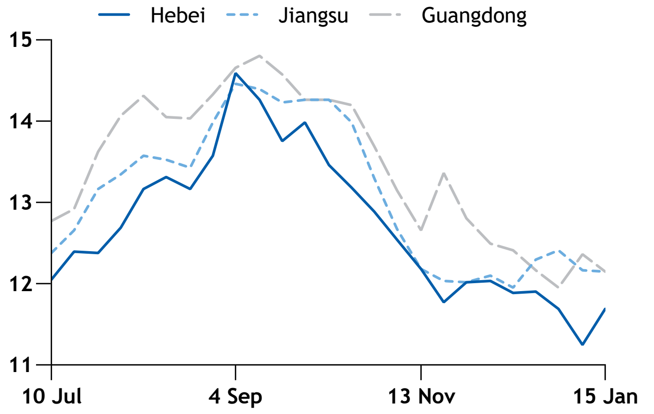
The decrease in pipeline imports could be attributed to colder weather in central Asia this winter, which may have left less gas available for export to China. Kazakhstan and Uzbekistan were colder in December 2024 than in the same month of 2023. Kazakhstan's largest city, Almaty, saw average daily lows of -6.4°C in December, compared with -3.4°C a year earlier, according to data from Speedwell weather.

That said, northern China has experienced milder weather this winter so far. Average daily lows in Beijing — a key gas demand centre in northern China — were around -4.5°C in December, compared with -7.6°C in December 2023.

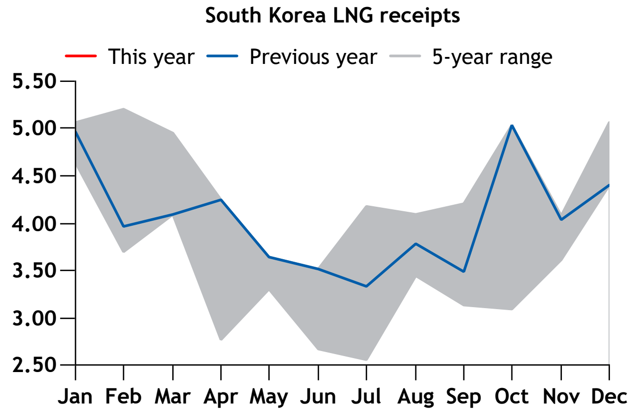
China LNG seasonality chart *mn t*



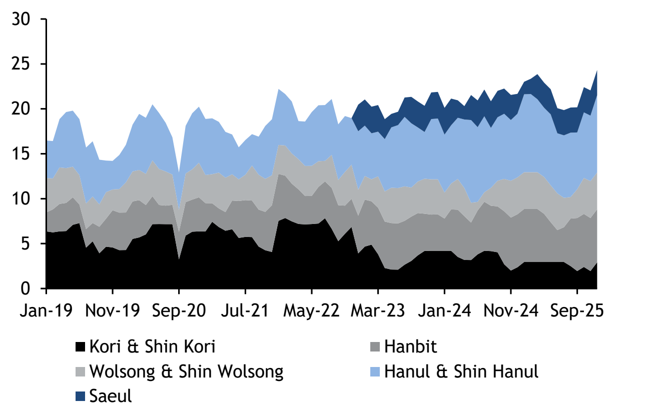
China domestic trucked LNG price *$/mn Btu*



South Korea LNG seasonality chart *mn t*

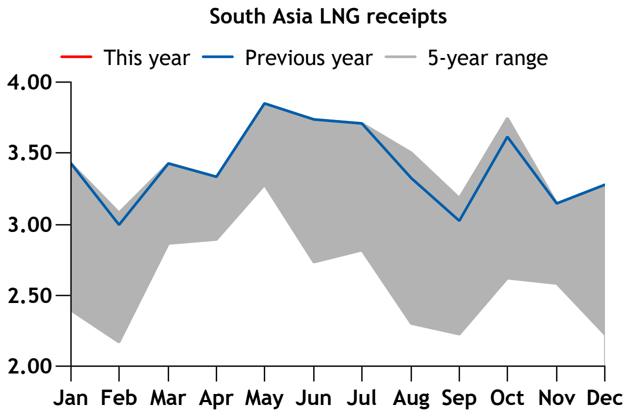


South Korea nuclear availability *GW*

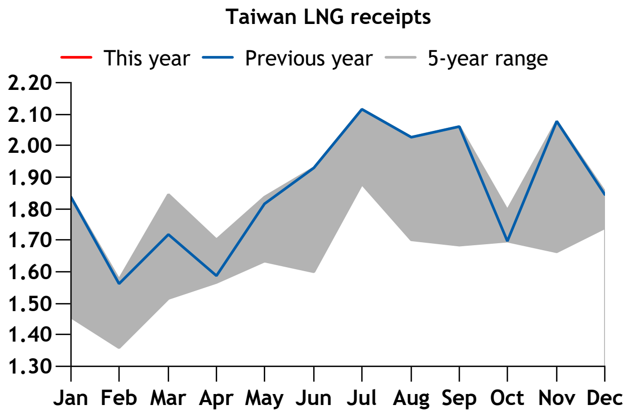


ASIA-PACIFIC

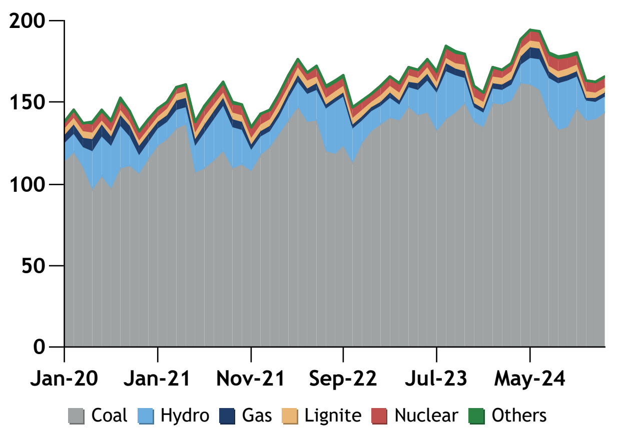
South Asia LNG seasonality chart *mn t*



Taiwan LNG seasonality chart *mn t*



India power generation mix *TWh*



Taiwanese LNG imports up on the year

Taiwan's annual LNG imports rose by 7.1pc on the year in 2024, tracking a rise in gas-fired power generation.

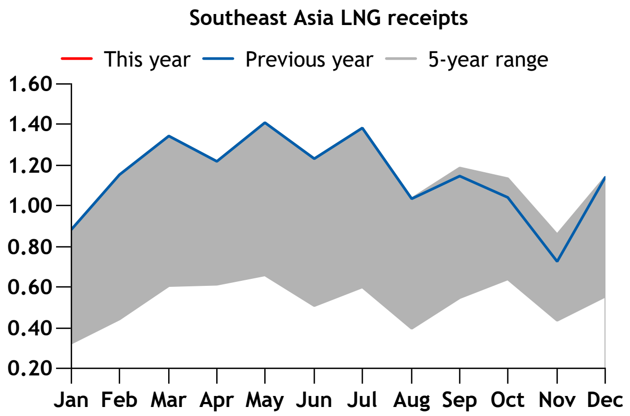
Total LNG imports stood at 21.51mn t last year, which compares with 20.1mn t a year earlier, customs data show. Australia was Taiwan's largest LNG supplier last year, accounting for 7.95mn t. Taiwan's imports of US LNG increased by 12pc on the year to 2.2mn t in 2024, up from just under 2mn t in 2023. US LNG accounted for around 10.2pc of total Taiwanese LNG imports last year, up from 9.75pc in 2023. And Taiwan is considering purchasing more US gas, on "reasonable terms", economic affairs minister Kuo Jyh-huei says.

Power generation data has not been released for December, but Taiwan produced 265.6TWh in January-November, a 2pc increase from the 259.9TWh produced over the same period in 2023, government data show. Gas-fired output rose by 10.4pc over the same time period, to 112.3TWh in 2024.

Taiwan has been prioritising a shift to gas-fired power generation, with the fuel making up around 40pc of the country's generation mix last year, up from less than 30pc in 2014. The increase in gas-fired generation can partially be attributed to a fall in nuclear power output, after the 951MW unit 1 of Taiwan's Maanshan nuclear plant shut in June, and maintenance took place at the same-sized Maanshan unit 2 from October. LNG has largely bridged the gap from the loss of nuclear output, accounting for an average 5-6pc of the island's generation mix over the past two years. Taiwan expects to be completely nuclear-free by May, when unit 2 at the Maanshan plant is scheduled to be decommissioned.

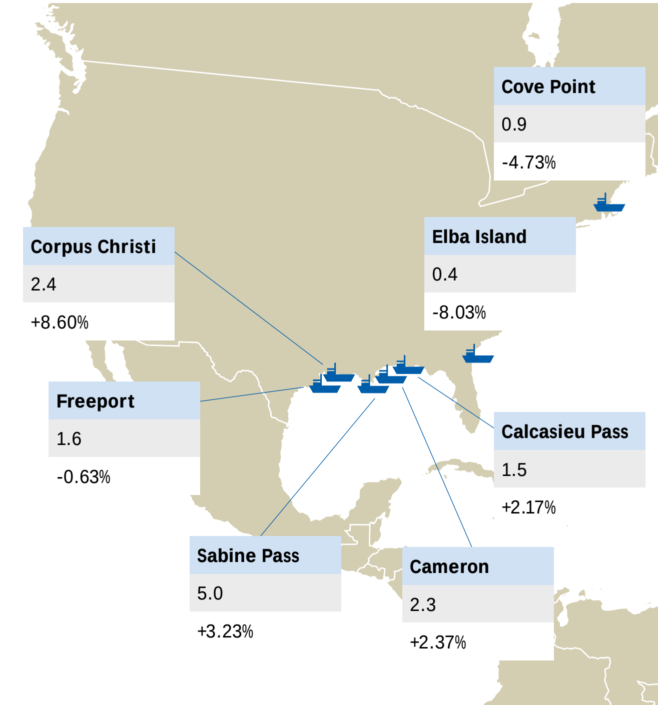
The island is also looking to gradually phase out coal, with the largest coal-fired plant — the 5.8GW Taichung plant — recently confirming plans to replace its coal-fired units with gas-fired units. The government aims to increase gas' share in Taiwan's generation mix to at least 50pc, which would require a further ramp up in LNG imports.

Southeast Asia LNG seasonality chart *mn t*



AMERICAS

Feedgas flows to US LNG terminals *trillion Btu/d*



US gas futures rally on colder weather

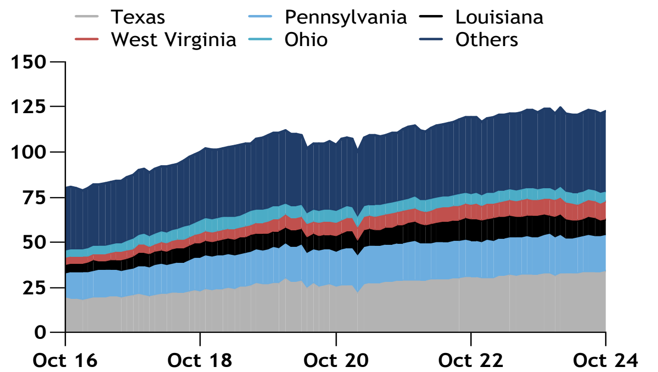
US natural gas futures trended higher over the first half of January, supported by expectations for colder-than-normal weather despite only a small change in the gas stockdraw.

Nymex gas for February delivery at the Henry Hub settled at \$3.934/mn Btu on 13 January, up from \$3.672/mn Btu on 6 January.

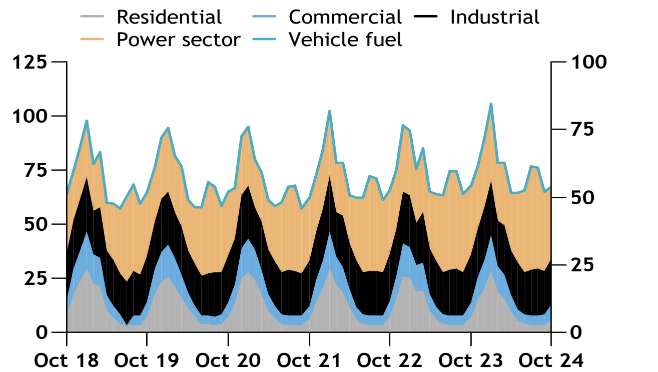
US gas futures and spot prices surged over the first half of the month, underscoring the arrival of cold weather across much of the US and key heating markets in the northeast and midcontinent. Temperatures across most of the US are expected to remain below average in the third full week of January, and it is already the usual peak month for winter heating demand in the US.

Unseasonably colder weather may lift gas storage withdrawals, with US government agency the EIA expecting socks' surplus to the five-year average to narrow over the balance of winter, according to its short-term energy outlook published on 14 January. Stocks are anticipated to hold 2pc more gas than the five-year average by the end of March — or 1.92bn ft³ (54mn m³) — whereas stocks were around 6pc above the five-year average in mid-November, the EIA says. Overall gas consumption is expected to remain flat on the year, at 119bn ft³/d this month, according to the EIA.

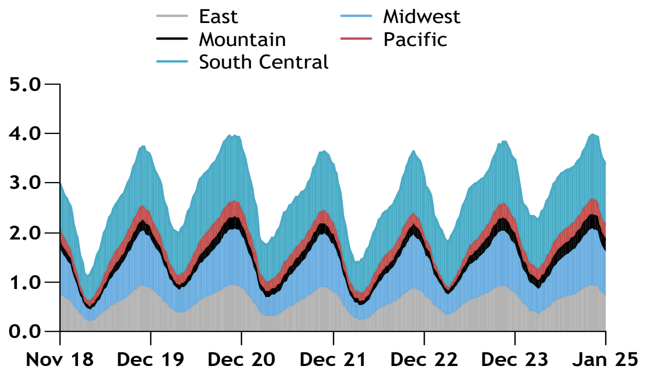
US production *bn ft³/d*



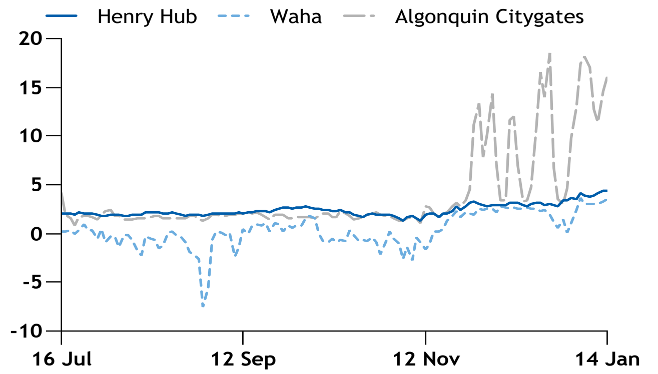
US demand *bn ft³/d*



US stocks *trillion ft³*



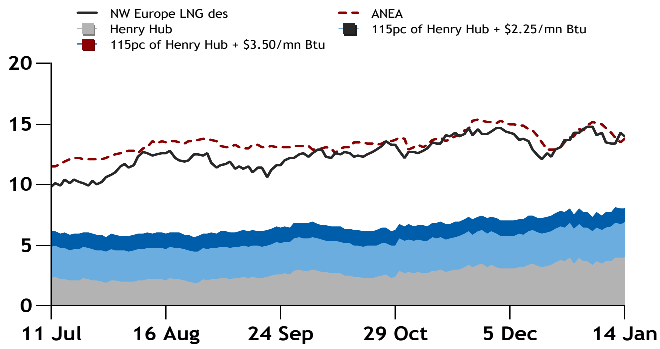
US domestic gas prices *\$/mn Btu*



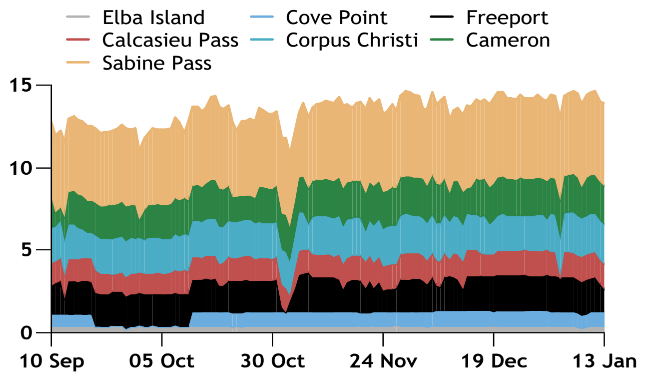
AMERICAS

US storage movements, stocks							*bn ft³*
Region	**3 Jan**	**27 Dec**	**Implied flow**	**Year ago (29 Dec)**	**% change**	**Five-year average (20-25)**	**% change**
East	737	745	-8	799	-7.8	759	-2.9
Midwest	881	914	-33	968	-9.0	911	-3.3
Mountain	255	262	-7	228	11.8	194	31.4
Pacific	293	295	-2	280	4.6	267	9.7
South Central	1,207	1,197	10	1,201	0.5	1,140	5.9
Total	**3,373**	**3,413**	**-40**	**3,476**	**-3.0**	**3,271**	**3.1**

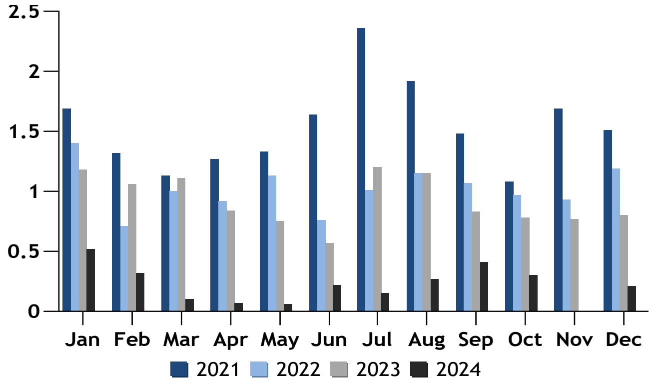
US long-term fob vs Europe, Asia spot des prices *$/mn Btu*



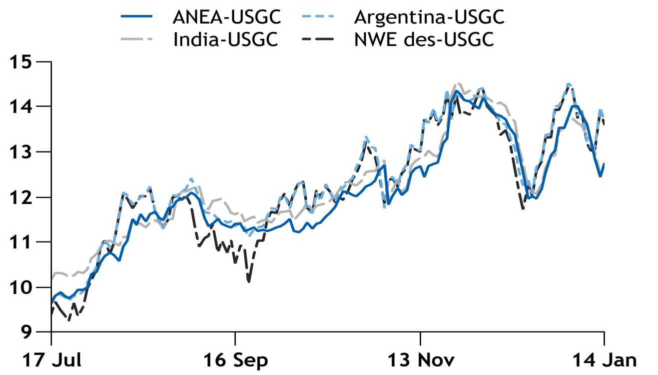
Feedgas flows to LNG plants *trillion Btu*



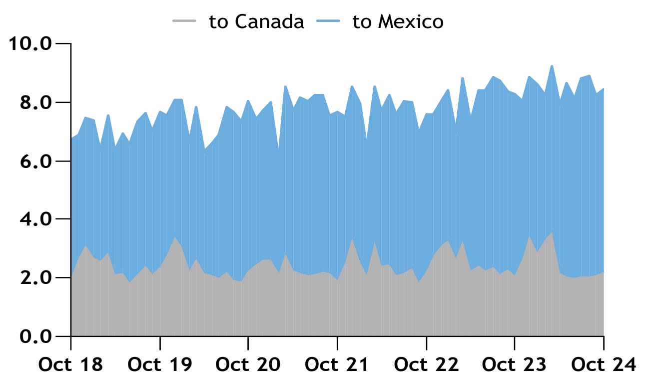
LNG deliveries via Panama Canal *mn t*



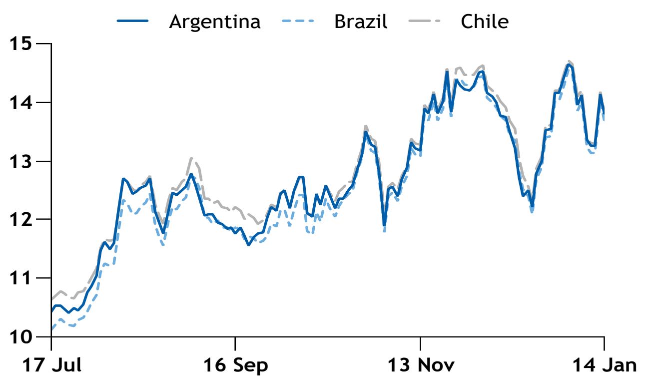
Netbacks to US Gulf coast *$/mn Btu*



US pipeline flows to Mexico *bn ft³/d*



LNG delivered to South America *$/mn Btu*



AMERICAS

South America LNG receipts *'000t*

Brazil's gas output falls in November

Brazil's natural gas production decreased by 2.8pc in November from the same month in 2023, according to data from hydrocarbons regulator ANP.

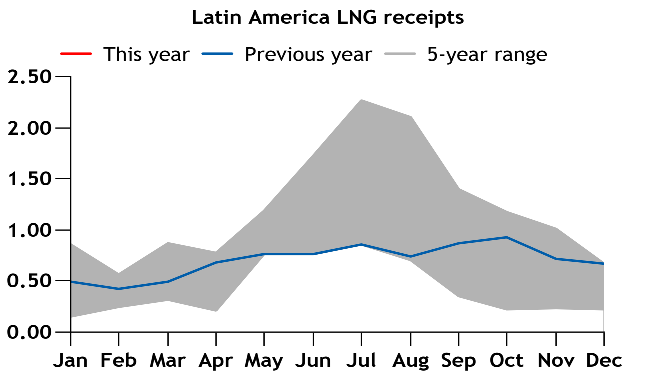
Brazil produced 157.6mn m³/d in November, down from 162.1mn m³/d during the same month a year earlier. And output decreased by 0.7pc from October, when the country produced around 158.9mn m³/d. Offshore fields accounted for 83.9pc of gas production, down from 85.2pc a year earlier.

Reinjections into oil fields decreased to 85.1mn m³/d in November, down by 0.8pc from nearly 85.8mn m³/d in November 2023. Gas reinjections may reduce further this year, because of a federal government decree signed in August, aiming to increase natural gas sales in order to lower domestic gas prices.

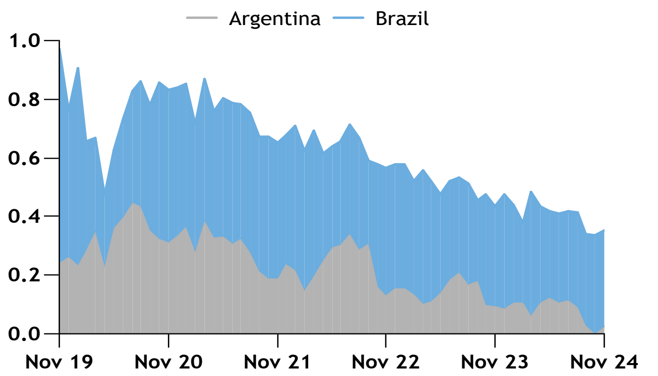
Brazil made 50.7mn m³/d of gas available to the market in November, lower by 10pc on the year and down by 9pc and on the month. Gas flaring increased by 69pc to 6.2mn m³/d from 3.9mn m³/d in November 2023, owing to the commissioning of floating production, storage and offloading unit *Marechal Duque de Caxias*.

Brazil expects supplies from Argentina's Vaca Muerta formation to increase this year, with 15.3mn m³/d having been approved by Argentina for export to Brazil to date.

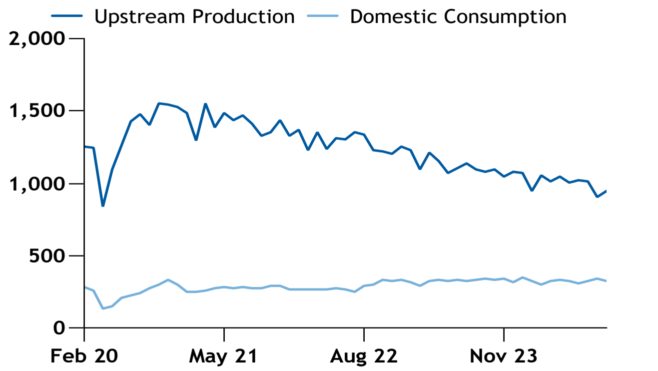
Latin America LNG seasonality chart *mn t*



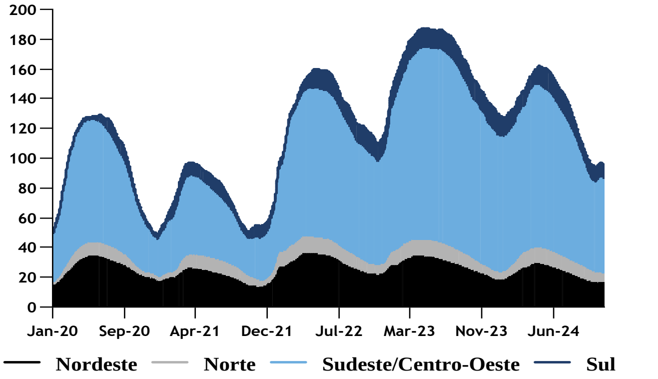
Bolivian flows to Argentina, Brazil *mn t*



Bolivian production and domestic demand *mn m³*

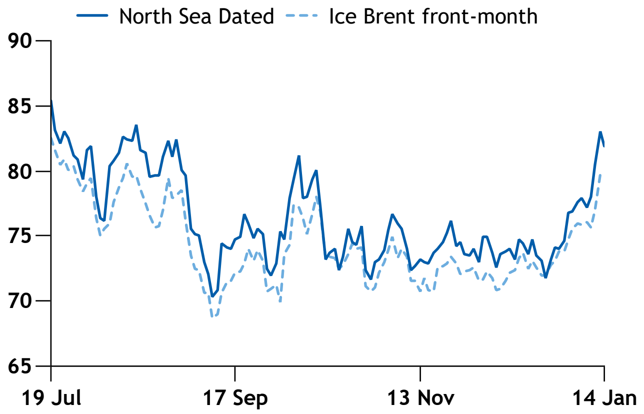


Brazil hydroelectric stocks *TWh*



RELATED MARKETS

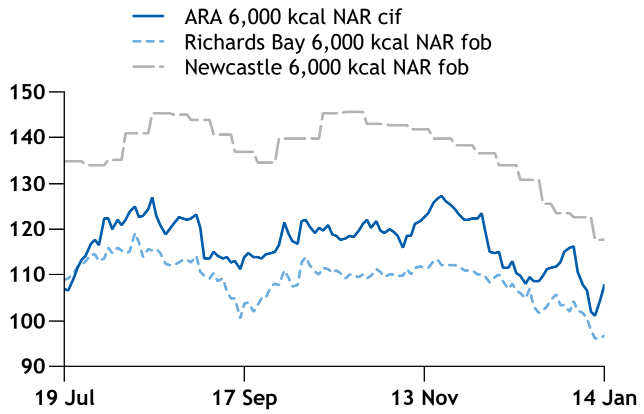
Crude prices $/bl



Crude prices rise owing to US sanctions

Atlantic basin crude benchmark North Sea Dated and US marker WTI surged over the past fortnight, as markets digested the impact of tightening US sanctions on Russian energy exports. The latest round of sanctions, announced on 10 January, targets nearly all of Russia's oil and gas producers and could disrupt supplies to core markets in Asia. Russian state-owned oil tanker owner Sovcomflot said the sanctions against its fleet create additional operational difficulties as well as risks to safe maritime operations. State-run Shandong Port in eastern China announced it will ban entry for any vessel on the US sanctions list and it will not provide port services for them. US crude inventories at the Cushing storage hub dropped by 959,000 bl to a more than 10-year low in the week to 3 January, US agency the EIA reported. Dated rose by $9.05/bl over the past fortnight, reaching $83.05/bl on 13 January, while WTI gained $7.83/bl to hit $78.82/bl.

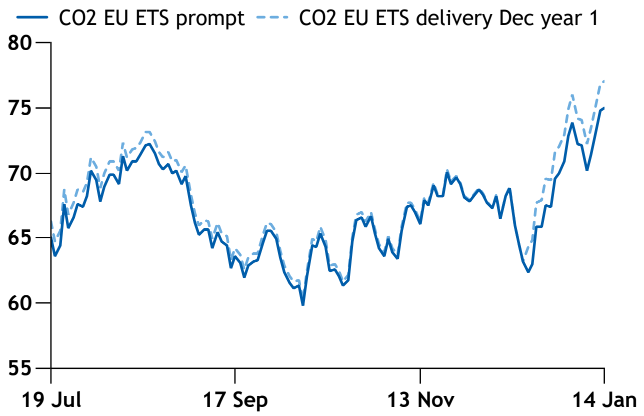
Coal prices $/t



Coal prices decrease as concerns ease

European thermal coal prices decreased over the fortnight to 13 January, as markets adjusted to the expiry of the Ukraine gas transit deal. The price of northwest Europe prompt-month delivery coal decreased from $112.75/t on 30 December to $104.54/t on 13 January. The price then gained significantly in the following session, increasing by $3.14/t on the day, tracking strength in the wider commodity complex owing to forecasts for colder weather and a wave of new US sanctions against Russian oil and gas producers. Prices were also supported by stronger coal demand in the German power sector a week earlier. Germany's average hard coal-fired generation increased by 1GW to 4.4GW over 6-12 January, according to Entso-E. South African coal prices remained stable, averaging $96.31/t in the week, as mild winter weather in key markets such as India and northeast Asia continued to weigh on demand for South African coal.

EU ETS €/t

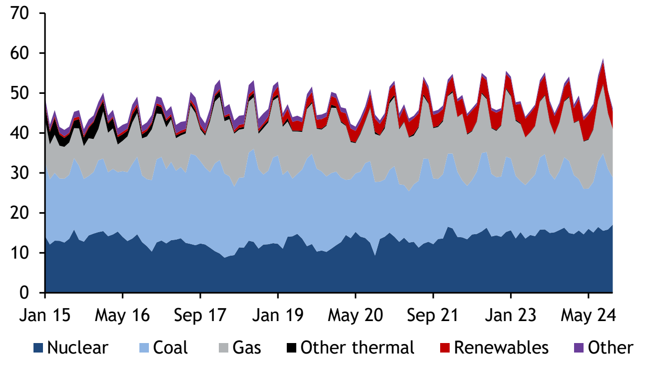


Voluntary carbon market stays muted

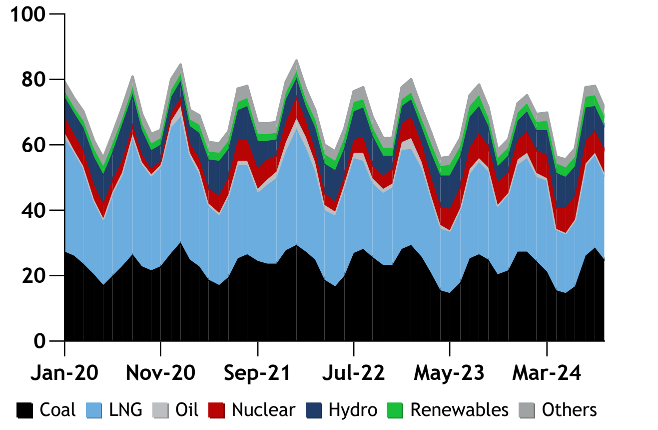
Buyers have been slow to return to the market this year so far, with no deals having been reported over the first two weeks of 2025. Offer prices receded marginally for renewable energy projects based in India, although bids have emerged for several Reducing Emissions from Deforestation and Degradation (REDD+) projects in southeast Asia. Buyers were willing to pay $3.20/t CO_2 equivalent (CO_2e) for credits generated by Cambodia's Keo Seima project in 2019 and $4.50/t CO_2e for credits generated by Indonesia's Katingan in 2020. Selling interest for projects operating under methodologies approved for the Integrity Council for the Voluntary Carbon Market's Core Carbon Principles (CCPs) has resurfaced, with offers reported for landfill gas (LFG) credits from Brazil and methane reduction credits from Bangladesh. A rare offer for CCP-approved LFG from the US was also heard.

GLOBAL GENERATION ECONOMICS

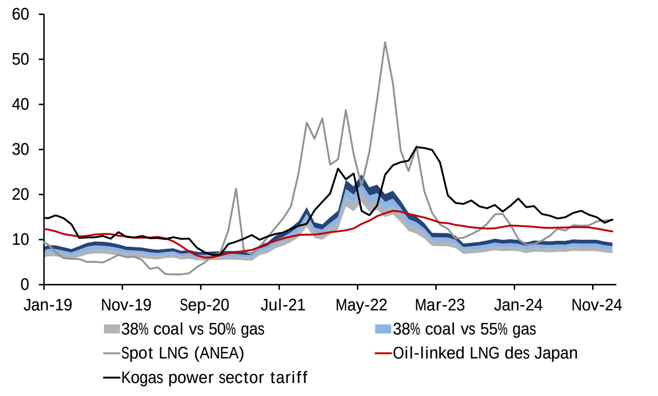
South Korea generation mix *GW*



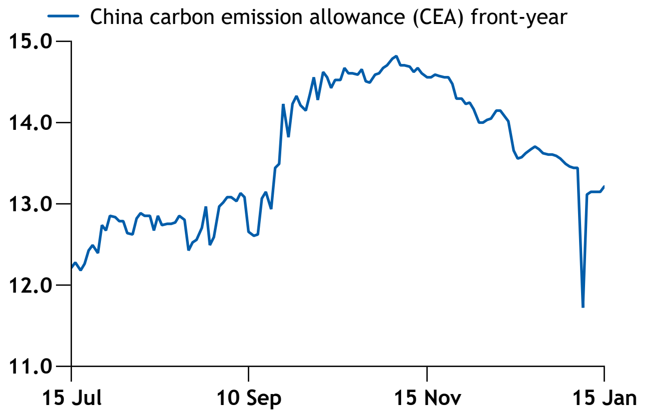
Japanese power generation mix *TWh*



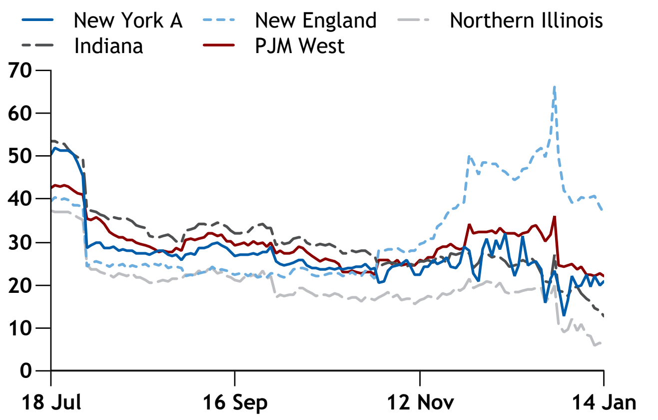
South Korea fuel switching *$/MWh*



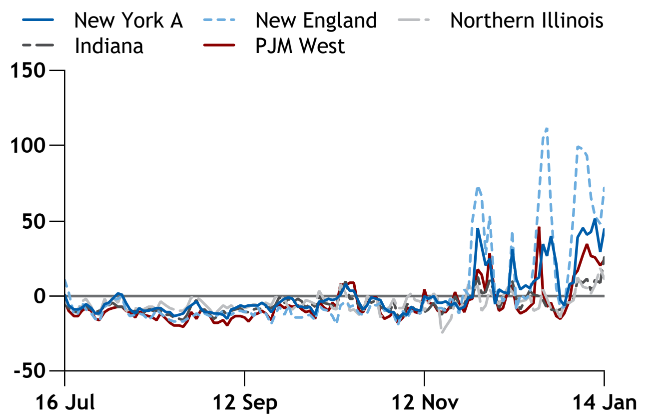
China carbon emission allowances *$/t*



US spark spreads *$/MWh*

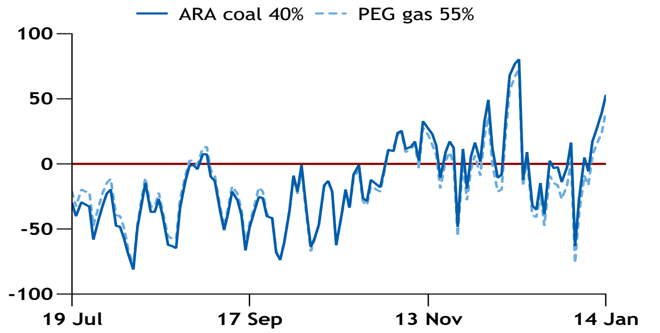


US dark spreads *$/MWh*

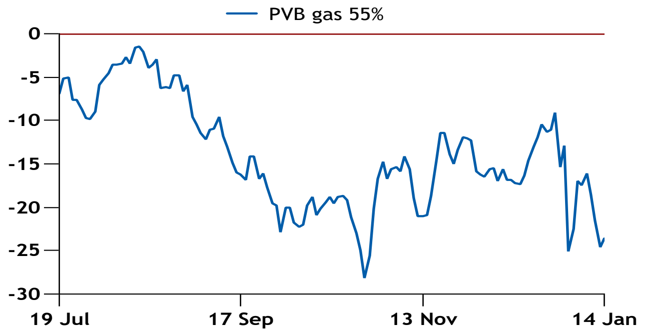


GLOBAL GENERATION ECONOMICS

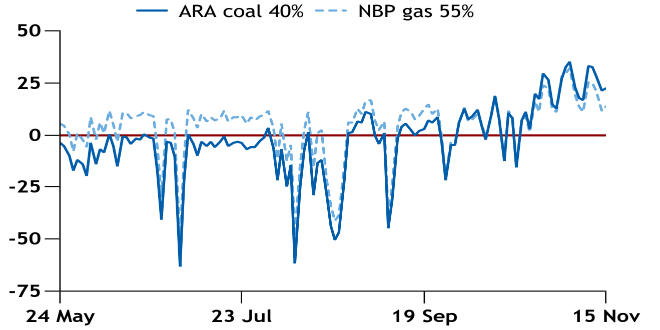
France ETS-adjusted spark spreads €/MWh



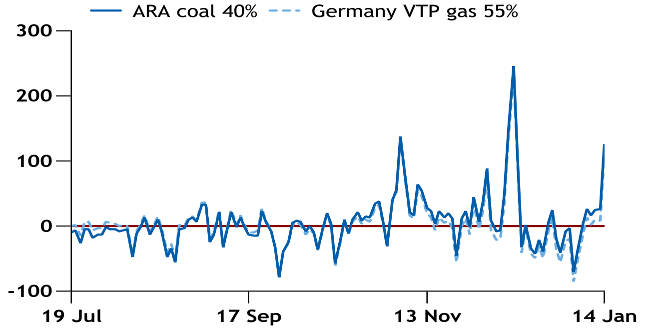
Spanish ETS-adjusted spark spreads €/MWh



UK sparks vs darks £/MWh

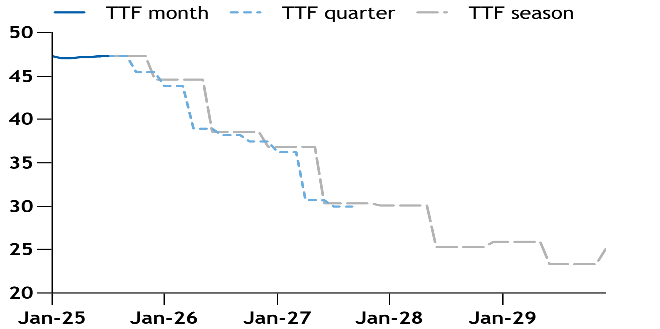


Germany sparks vs darks €/MWh

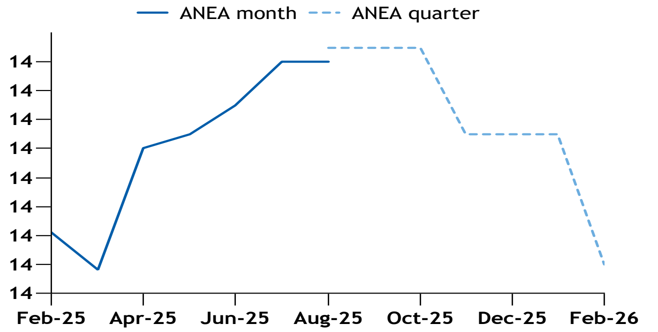


FORWARD CURVES

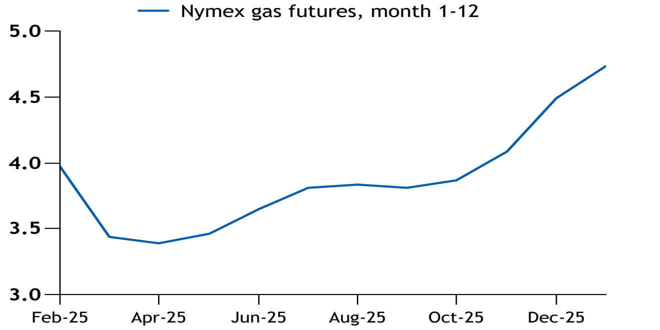
TTF €/MWh



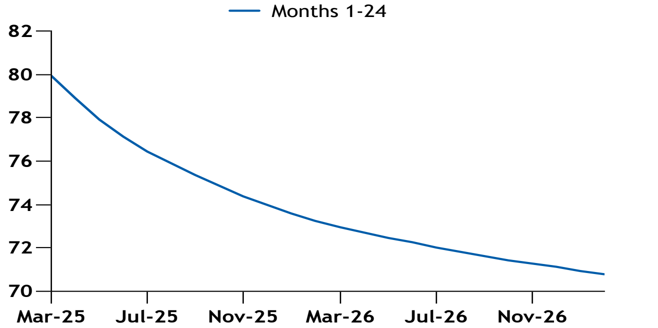
ANEA $/mn Btu



Henry Hub $/mn Btu

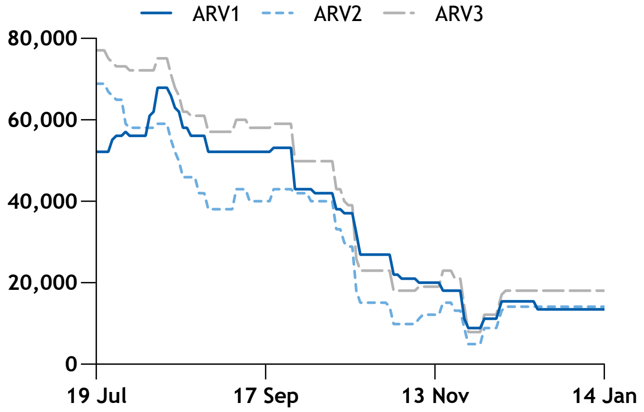


Ice Brent $/bl

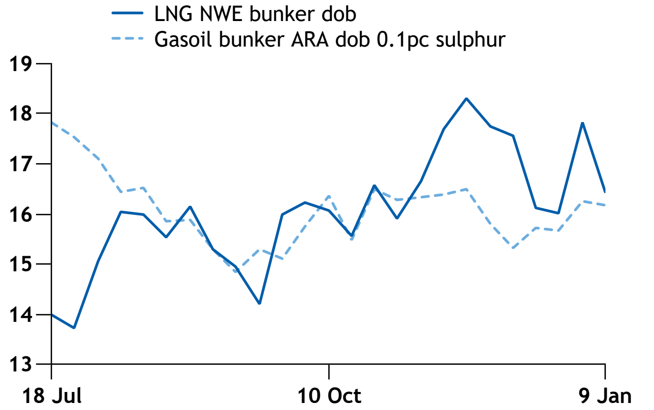


FREIGHT AND LNG AS MARINE FUEL

Argus Round Voyage (ARV) rates $/d



Marine fuels competition $/mn Btu



Argus *Global Gas Markets* is published by Argus Media group

Registered office
Lacon House, 84 Theobald's Road,
London, WC1X 8NL
Tel: +44 20 7780 4200

ISSN: 3033-4306

Publisher
Adrian Binks

Global compliance officer
Vladas Stankevicius

Chief commercial officer
Jo Loudiadis

President, Expansion Sectors
Christopher Flook

Global head of editorial
Neil Fleming

Editor in chief
Jim Washer

Managing editor
Andrew Bonnington

Editor
Antonio Peciccia
Tel: +44 20 7780 4224
lng@argusmedia.com

Customer support and sales:

support@argusmedia.com
sales@argusmedia.com

London, Tel: +44 20 7780 4200
Houston, Tel: +1 713 968 0000
Singapore, Tel: +65 6496 9966