Argus Global Gas Markets

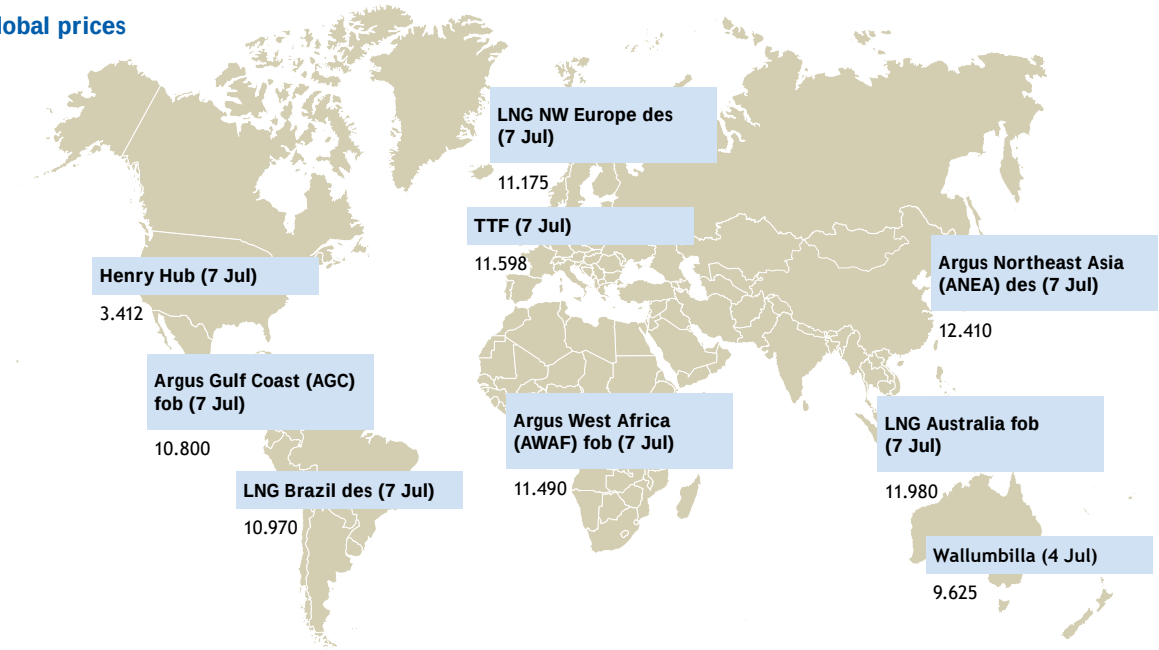
Gas and LNG markets, projects and infrastructure

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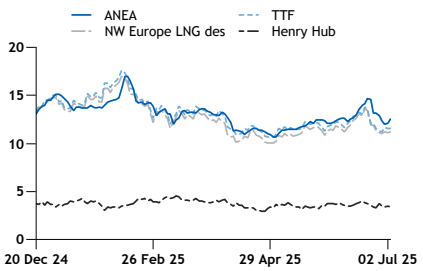
Key global prices

$/mn Btu



Key global prices

$/mn Btu



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Executive summary

European underground storage capacity is one of the key flexibility tools, not just for the region but the global market too. More capacity bookings at German sites may support injection demand in the coming weeks, but Berlin's apparent decision not to intervene in the market still cast doubts on the outlook for security of supply next winter, and also for the fate of storage facilities in the long term (*p2*).

While opposition from Hungary and Slovakia so far has stalled European plans to increase sanctions on Russia, the Kremlin has been engaging in a new and broader phase of its energy diplomacy push (*p3-4*). Poland is emerging as the key transit market for gas supplies heading to Ukraine, but the latter country's projected import needs may require supplies from more than one route (*p7-8*). The Japanese government is considering setting a firm target for nuclear capacity, following on from the approval of its energy strategy earlier this year (*p5*). The Australian government is reviewing existing regulations on natural gas supply in a bid to tackle eastern Australia's projected supply shortages, but doing so may affect the prospects of its LNG exporters (*p6*). The Mexican government has set up a target to boost natural gas output, but state-owned Pemex remains entrenched in a culture heavily inclined towards investment in crude production (*p9*).

Meanwhile, investment decisions in new liquefaction capacity have stepped up globally in the first half of 2025, once again led by the US and the Atlantic basin, which may alter the supply-demand balance between the Atlantic and Pacific basins going forward (*p10*).

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EDITORIAL

Taking off the stabilisers

Europe's storage buffer is at its lowest since 2021, which could increase the risk of global gas price spikes this winter

At the height of the European gas crisis in 2022, the German state spent nearly €8bn ($9bn) on gas to put into storage to safeguard winter supply. Three years later and the government would rather leave the fate of the country's gas stocks in the hands of the market. Lower German stocks will reduce the global market's buffer to deal with the unexpected this winter, but the decision to let market forces work without distortion brings the gas market a step closer to the pre-2022 normal.

Germany has more underground storage space than any other EU state, largely thanks to Russian gas giant Gazprom's buildout of infrastructure in the early 2010s, after it stopped using storage sites in western Ukraine. When the German government slashed the national start-of-November target to 70pc from 90pc in June, it removed about 49TWh of enforced summer gas demand. The difference equates to about 44 standard-sized LNG cargoes.

Even this 70pc goal looks ambitious now. About 65pc of the country's storage space had been booked by the start of July, and the government says it will not intervene to make sure individual sites meet their targets. It is already too late for the slowest-cycling facilities to fill up substantially before winter.

German lawmakers took their direction from the EU, which signalled that it intended to relax the bloc-wide storage mandate. The European Parliament finally approved its revised law on 8 July, introducing an up to 15-percentage point leeway from the 90pc storage obligation under certain broadly defined conditions, on top of exemptions under the old rules. This loosening has already had some pay-offs — summer-winter spreads normalised after the previously rigid regulations helped push summer prices to an unusual premium over winter prices and storage bookings have now increased. Operators sold more than 5TWh of combined capacity at the Rehden and Katharina sites on 8 July alone, thanks to wider seasonal spreads.

At cross purposes

Europe's storage is a key asset for the global market, and reduced access to this tool will make it harder to deal with supply disruptions or sustained cold snaps

But if the German government did intervene to top up the country's gas storage, it would not get this money back. It was forced to axe its controversial storage levy on gas exiting the German grid at cross-border points last year, in response to opposition from neighbouring countries. Berlin will get rid of the charge at domestic points from the start of 2026, as part of a wider effort to reduce energy costs.

Is Europe — and by extension, the global LNG market — resilient enough to get through the winter without price spikes, now that the storage buffer is at its lowest since 2021? Forward prices suggest there are no great concerns. The *Argus* TTF front-winter contract was at just above €36/MWh on 8 July, 20pc below the average for this date in 2023-24 and 80pc lower than in 2022.

Europe has built out its regasification capacity considerably since 2022, while a wave of new LNG export projects is under way. The continent has adapted to losing most of its Russian gas, although it is not all of the way there — the EU plans to phase out Russian gas entirely by the end of 2027. At the same time, below-normal European stocks will mean the global LNG market operates on finer margins this winter. Europe's gas storage remains a key flexibility asset for the global market, and reduced access to this tool will make it harder to deal with unplanned supply disruptions or sustained cold snaps.

The lack of commercial incentive for trading companies to use storage poses longer-term questions. If summer-winter spreads are too narrow to encourage traders to use storage, and governments opt against creating their own stockpiles, would it lead to more site closures? This is already on the horizon — the Netherlands plans to close its largest site, Norg, while the UK's Centrica has warned it may be forced to shut the country's Rough site unless the government offers support.

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RUSSIA

Russia casts its net wider for gas and LNG customers

Any sizeable redirection of Russian LNG could significantly affect global gas markets, writes Bonnie Lao

As the EU advances its plans to phase out residual Russian energy supplies, Moscow is furthering its quest to seek new trade partners outside Europe, including targeting some LNG producers and potential re-exporters.

Russia has had "high-level" conversations with Malaysia, Indonesia, Turkey and Mexico about potential LNG sales and "developing gas market and gas trade co-operation", according to Russian energy minister Sergei Tsivilev and deputy prime minister Alexander Novak. And Russia and Vietnam strengthened their energy ties during Vietnamese leader To Lam's visit to Moscow in May, with the two countries having signed an intergovernmental agreement to partner on upstream activities and committing to LNG trade. Vietnam's 1mn t/yr Thi Vai regasification terminal received its first Russian LNG delivery on 26 June.

Russia has pushed energy diplomacy since losing much of its European market share in the wake of its full-scale invasion of Ukraine in 2022. So far it has focused mostly on China, but Beijing's reluctance to agree to build the proposed 50bn m³/yr Russia-China Power of Siberia 2 (PoS 2) pipeline, coupled with the EU's renewed push to completely phase out Russian energy imports by 2027, may have prompted the Kremlin to look for more alternative markets.

Russia is currently unable to substantially increase its LNG exports because of US sanctions that have prevented it from developing its LNG infrastructure

Russia is currently unable to substantially increase its LNG exports to offset even some of the expected loss of pipeline deliveries to Europe, in part because US sanctions have prevented it from developing its LNG infrastructure. Three out of Russia's five operational LNG export terminals have been sanctioned by the US and the EU, including two small-scale facilities — the 1.5mn t/yr Portovaya and 660,000 t/yr Cryogas-Vysotsk terminals — and its largest terminal, the 19.8mn t/yr Arctic LNG 2 project. Arctic LNG 2 is partially operational but it has been unable to deliver any cargoes to customers since it started up in January 2024 because of US sanctions.

Russia's other two export facilities — the 17.44mn t/yr Yamal LNG and 9.6mn t/yr Sakhalin 2 — are not subject to sanctions but are already operating at above nameplate capacity, limiting their scope for additional deliveries to new markets. Yamal LNG produced more than 21mn t/yr of LNG in 2023-24, according to its private-sector owner, Novatek. Sakhalin 2 sold 11.5mn t of LNG in 2022, according to state-owned Sakhalin Energy, but output has been curtailed since 2023 to prolong field and equipment life.

Downs and ups

Russian gas and LNG deliveries to the EU fell to 51.7bn m³ in 2024 from about 150bn m³ in 2021, data from the European Commission show. This reduction has been partly offset by a parallel ramp-up in exports to China through the 38bn m³/yr PoS 1 pipeline, although the gas that Russia sells to China comes from different fields than those that supply Europe. PoS 1 flows were slated to reach capacity this year, from about 10bn m³ in 2022, but even if this is achieved, Russia would still have a sales deficit of about 70bn m³/yr compared with 2021 — a shortfall equivalent to approximately 54.4bn t/yr of LNG.

Russian supplies to Europe have dropped further this year so far, after transit flows through Ukraine halted on 1 January. And Europe-bound flows could be phased out entirely if proposed EU legislation gets the go-ahead. The latest draft proposal from the European Council seeks to ban Russian pipeline gas and LNG imports into the bloc from 1 January 2026, with a grace period until 1 January 2028 for gas under long-term supply deals signed before 17 June 2025. The draft proposal also includes a ban on long-term LNG import terminal services to Russian or Russia-controlled firms from 1 January 2026, so that import capac-

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RUSSIA

ity can be made available for LNG of non-Russian origin. Such a ban on Russian LNG imports to the EU could mean nearly 16mn t/yr of Yamal LNG will need to be redirected to new non-EU buyers, based on trade flow data for 2024 from vessel-tracking firm Kpler. This could further alter global LNG trade dynamics and possibly free up more spot supplies, particularly if Russia is willing to sell LNG at below prevailing spot prices in the basin.

Malaysia and Indonesia are large LNG exporters but both have exported below capacity in recent years and expect to become net LNG importers in the future, on account of declining domestic gas reserves. Indonesia already consumes more than 6mn t/yr of LNG because the country's gas grid is insufficiently developed to allow domestic gas to reach all parts of the archipelago.

Mexico nearly stopped importing LNG at the start of this decade and is gearing up to become an LNG exporter using US feedgas, although some of its projects have not been able to make much progress in recent years.

Turkey has long aimed to become a new supply hub for Europe, although this ambition has been met with scepticism on the EU side because of the large share of Russian gas in its supply mix. Turkey received only 9mn t of LNG in 2024, Kpler data show, using up only 30pc of its regasification capacity. This suggests Turkey has scope to receive additional Russian LNG cargoes for domestic use, particularly considering its rising power demand and the unreliability of piped Iranian flows. It then could export its domestic production by pipeline to Europe. But it is unlikely that Russian LNG would be priced low enough to compete with domestic pipeline gas, market participants say.

Turkey has long aimed to become a new supply hub for Europe but this has met with scepticism from the EU because of the large share of Russian gas in its supply mix

Any sizeable redirection of Yamal LNG cargoes could significantly affect the LNG freight market, given that journey times to Asia-Pacific would be much longer compared with deliveries to Europe, as well as logistical headwinds.

The majority of Russian LNG shipped to Asia-Pacific travels around the Cape of Good Hope, because the shorter northern sea route (NSR) is open for only a few months each year. And NSR shipments are probably already at capacity, based on the size of Russia's unsanctioned Arc7 fleet. Journeys through the Cape of Good Hope are more expensive than NSR transits, but supply delivered along this route could still be economically attractive to southeast Asian exporters.

Changing places

For every 1mn t of imported Russian LNG, Indonesia could reallocate an equal amount of domestically consumed LNG for spot northeast Asian buyers for an additional price benefit of about $90mn, *Argus* estimates. This assumes Indonesia buys Russian supply at a long-term price in line with Taiwan's average purchase price of Yamal LNG and sells more of its domestic LNG production, which is assumed to cost $8/mn Btu, at the average delivered Argus Northeast Asia (ANEA) price from 2024, while also saving three-days' worth of boil-off because of the shorter journey. While long-term sales and agreement contracts differ in their indexation, Taiwanese purchases of Russian LNG can be used as a delivered long-term indication because they are typically bought at a substantial discount to the ANEA des price.

Any additional spot supply freed up from southeast Asian producers would probably stay within the Pacific basin. All Malaysian export cargoes are delivered within Asia, and Indonesia last exported a cargo to Europe in May 2023, according to Kpler data. If Yamal LNG can be exported at low enough long-term prices to southeast Asian LNG exporters, nearly all Russian supply would functionally become Pacific basin supply, altering the Atlantic-Pacific inter-basin supply relationship and arbitrage opportunities.

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JAPAN

Tokyo considers firmer nuclear capacity target

Japan could face an electricity supply shortage unless it builds more nuclear and thermal power generation capacity, writes Motoko Hasegawa

A committee under Japanese trade and industry ministry Meti is working to set a target for nuclear capacity, which Tokyo sees as necessary to enhancing energy security by reducing reliance on imported coal and LNG and achieving the country's net zero emissions goal. But utilities remain under pressure to secure more LNG supply, particularly given the uncertain power demand outlook.

The committee argues that setting a quantitative target for nuclear capacity would increase predictability for the sector, which should boost investment in power plants and supply chains and help the industry secure the required human resources. But it acknowledges that setting a definitive goal with a specific timeline remains a challenging task, particularly given the significant uncertainties over lead times for developing next-generation reactors, the status of existing ones, as well as the evolution of power demand and other generation sources.

Meti's move follows repeated requests by Japanese industry group the Federation of Electric Power Companies that the government's strategic energy plan (SEP) clearly state that it is necessary for Japan to not only restart existing nuclear reactors but also build new reactors and set a clear goal to develop next-generation reactors. The government eventually approved its new SEP in February — such a quantitatively clear statement was not included but it did set an implicit capacity target, with a goal that nuclear generation account for 20pc of the country's power mix in the April 2040-March 2041 fiscal year. This provides the "rough direction" on which the new target should be based, a committee member says.

Setting a definitive goal is challenging given the significant uncertainties over lead times for developing next-generation reactors, the status of existing ones and the evolution of demand

Power demand could reach 1.2PWh by 2040, according to the SEP. To meet 20pc of this projected demand with nuclear energy, Japan would need 29-30GW of nuclear capacity, assuming all reactors run at an average 90-95pc load factor and depending on maintenance required. Japan has 14 operational reactors with a total installed capacity of 13.3GW at present. The country still has 19 idled reactors with a combined capacity of roughly 20GW that have not been formally slated for decommissioning, so the country may be able to meet this capacity target without having to build new reactors. But it remains unclear how many of the idled reactors will resume operations in the future.

Japanese power demand may grow to 1.25PWh by 2050, as rapid electrification and digital transformation are expected to more than offset any energy-saving efforts, according to scenarios released on 25 June by nationwide transmission system operator Occto. Japan will face an electricity shortage unless the country expands its nuclear and thermal generation fleet, Occto says.

Into the unknown

The complexities of setting such targets and developing the necessary infrastructure are compounded by the uncertainties surrounding the evolution of power demand, particularly given the generally high but still wildly diverging expectations of power demand growth from data centres developing artificial intelligence.

This leaves Japanese utilities with little alternative than to firm up their fuel supplies for the foreseeable future, particularly given that many LNG deals are set to expire in the coming years. Japan's largest utility, Jera, has about 16mn t/yr of long-term supply contracts that will expire in the 2030s. Jera expects to have to replace all of this and possibly secure even more, depending on LNG and power demand growth, chief executive Yukio Kani said at a press conference in late June.

But the volatile outlook for power demand may be prompting the country's LNG importers, including Jera, to secure contracts with more flexible terms that allow them to resell excess cargoes. Jera is also looking to build a portfolio of price formulas, such as prices linked to crude, the US' Henry Hub and spot LNG, Kani says.

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AUSTRALIA

Canberra reviews federal gas reservation scheme

The new study will seek to find out why Australia's attempts to prevent supply shortfalls have so far been unsuccessful, writes Tom Major

Australia's eastern LNG projects could be ordered to ringfence a portion of all new gas supply for local markets as early as next year, as a review gets under way into the country's regulations on boosting dwindling domestic supply and rising prices.

In the wake of repeated warnings of a continued decline in domestic gas supply, Canberra on 30 June announced a six-month inquiry into the Australian Domestic Gas Security Mechanism — through which the government can force exporters to redirect gas to local markets — the gas market code and A$12/GJ ($8/GJ) price cap and the interim agreement in force with Gladstone-based LNG exporters. Australian gas must be available for Australian users at reasonable prices, Labor energy minister Chris Bowen said on 1 July. Australia's aluminium, steel and cement industries, and the 5mn Australians who heat their homes with gas, must have access to supply, and this must be achieved through better policy settings, he said.

The review will study why Australia's existing policies have not erased the supply shortfalls expected from about 2029. Growth in gas-fired generation as coal-fired plants retire could put the system under strain, if attempts to bring down household and industrial demand are unsuccessful. This may mean that LNG projects, which absorb about three-quarters of eastern Australia's gas, may be required to prevent serious energy shortages, as well as extra gas piped south from Queensland's coal-bed methane fields, new fields in southeastern regions such as the Otway and Bass basins and possible LNG imports.

Growth in gas-fired generation as coal plants retire could put the system under strain, if attempts to bring down household and industrial demand are unsuccessful

The sales and purchase agreements held by Gladstone's LNG plants are set to expire sequentially and in line with the retirement of coal-fired generators, possibly leaving an angle for Canberra to negotiate greater supply. Gas available to domestic users may rise sharply when Queensland's LNG projects reach the end of their current contracts in the early to mid-2030s. But until then, a projected supply gap could be bridged with LNG imports from terminals such as New South Wales' 2.4mn t/yr Port Kembla, which could be moved across New South Wales and Victoria through the planned east coast gas grid expansion mooted by pipeline operator APA. The two states aim to rely heavily on renewable power supported by gas-fired generation from the next decade.

But at full capacity, pipelines linking Queensland's coal-bed methane fields to the southern states can meet only 20pc of their peak winter demand, which exceeds 2 PJ/d. Southern energy markets are set to face a power supply crunch, particularly as ExxonMobil's 700 TJ/d Longford gas facility in Victoria will close its two remaining generators in 2028 and 2033, and the state's 1.48GW Yallourn coal-fired power station is set to shut in 2028. Victoria's peak day supply is projected to fall to 895 TJ/d in 2029 from 1.296 PJ/d in 2025.

Timing matters

Victoria has attempted to cut demand, but additional measures will still be needed, particularly as planned renewable power infrastructure has been delayed by two years to 2030. Extra northern supply, further storage capacity, LNG imports and new southern fields may need to be carefully weighed to attract investment.

Canberra's A$12/GJ price cap to bring down gas prices in the wake of Russia's invasion of Ukraine probably froze investment in new upstream supply. The country could consider a domestic reserve, like that instituted in the country's LNG powerhouse, Western Australia (WA), but it would need to be carefully designed. Domestic users have received about 8pc of the state's offshore gas output since 2006, an inquiry found last year — well below the 15pc required from each project under the reservation policy. WA last year amended its ban on onshore gas exports to try and prevent shortfalls when coal-fired generation ends in the 2030s.

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BRIEFING: GAS ROUTES TO UKRAINE

Poland makes progress as key gas gateway to Ukraine

Shipping gas through Poland may be the cheapest option, but capacity is insufficient to meet all of Ukraine's import demand, write Brendan A'Hearn, Antonio Peciccia and Natasha Fielding

Ukraine received record-high gas flows at its interconnection point with Poland at the start of July — after nearly all capacity available at the point was sold at a June auction — highlighting a market preference for the Polish route over the costlier Greek gas corridor.

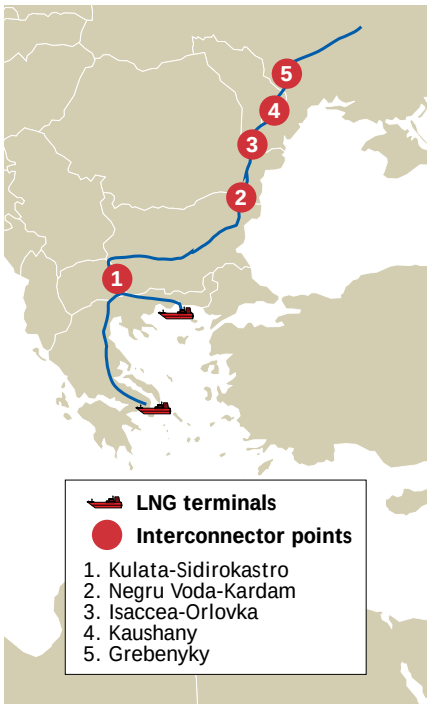
Flows from Poland to Ukraine at the GCP Gaz-System/UA TSO interconnection point jumped to 94.5GWh/d on 1-8 July from 58.5 GWh/d across the whole of June, peaking at 100.2 GWh/d on 4 July — an all-time high for the point. The sizeable jump in flows on the month follows a June auction that allocated an additional 28.6 GWh/d of Polish exit capacity towards Ukraine — slightly short of the total 30.6 GWh/d on offer, but this was largely because demand exceeded available capacity when bidding commenced, meaning the auction continued for multiple rounds and eventually closed at nearly three times the starting price.

This additional allocation brings the total booked unbundled Polish exit capacity for July to 65.8 GWh/d, out of a technical capacity of 67.8 GWh/d. Physical flows could exceed this thanks to a temporary solution worked out by the Ukrainian and Polish gas transmission system operators, GTSOU and Gaz-System, respectively, which nearly doubles the point's available capacity, although this is only available for daily and within-day products. Additional capacity is set to become structurally available later this year, once Gaz-System completes modernisation works at the Hermanowice metering station.

The record-high sales seen in the Polish auctions contrast with the results of a parallel auction on 23 June for bundled transmission capacity from Greece to Ukraine — dubbed Route 1 — in which there was little market interest. Just over 1.7 GWh/d were allocated out of a total 29.8 GWh/d on offer, results on the Regional Booking Platform show. The low sales may be because these bookings were test volumes, ahead of potentially larger bookings later in the summer if spreads widen sufficiently, market participants told *Argus*. Two international firms booked capacity during the auction, Greek grid operator Desfa says.

The other two routes to bring gas into Ukraine are through Hungary and Slovakia. Deliveries to Ukraine's border with Hungary have hovered at about the point's technical capacity of 104 GWh/d since the start of summer, as this is the cheapest transport option. Transport costs to bring gas across the Slovakia-Ukraine border are much higher. Flows to Ukraine from Slovakia started slowly in mid-May, ramping up sharply from 1 July to hover at 94-95 GWh/d since then.

Potential Greece-Ukraine gas flows



Bundle of energy

Route 1 bundles together capacity at the Kulata-Sidirokastro, Negru Voda-Kardam, Isaccea-Orlovka, Kaushany and Grebenyky interconnection points, with a 25pc discount applied at all points except Isaccea entry, Kaushany exit and Grebenyky entry, where a 46pc discount is already applied by the Ukrainian operator. The bundled product aims to make the southern route more competitive against other routes, which would all be much cheaper otherwise, *Argus* estimates.

No capacity was sold at the first Route 1 auction on 29 May, as trading firms had questioned the product's compliance with EU law and its restrictive rule set, and because there was insufficient economic incentive to book. A later amendment by the Greek regulator allowed nominations from the Greek virtual trading point to be included in the bundled product.

The cheapest way to ship gas to Ukraine is probably the Polish route, with LNG importers only having to pay regasification costs at the 6.5mn t/yr Swinoujscie terminal, €2.64 ($3.10) in entry-exit fees at the Polish grid and an entry fee into Ukraine. These costs add up to about €5.34/MWh for annual capacity, with capac-

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BRIEFING: GAS ROUTES TO UKRAINE

ity booked for shorter periods typically being more expensive. Such costs may have been embedded in the final price paid by Ukraine's state-owned gas and oil firm, Naftogaz, in its recent deals with Poland's state-controlled energy company, Orlen. The two firms signed their fourth supply deal in early July for an additional 140mn m³ of gas, bringing the total amount of contracted supply to 440mn m³ — broadly equivalent to 342,000m³ of LNG — which Orlen will deliver either through Swinoujscie or the 2.9mn t/yr Klaipeda terminal in Lithuania, where it also holds capacity. This latter option adds about €0.62/MWh in entry-exit fees on the Lithuanian grid, but these are partly offset by lower regasification costs at Klaipeda.

In contrast, regasification fees at Greek terminals and transmission capacity across several countries in the Balkan peninsula add up to nearly €11/MWh, *Argus* estimates. Applying the discounts offered with the Route 1 bundled product brings this down to about €7.64/MWh, still much higher than the Polish route but possibly competitive with other supply corridors carrying gas from Germany, the Netherlands or Italy. These routes are likely to be more expensive than the bundled Route 1 product, particularly if gas is shipped through the expensive Slovak network rather than the cheaper but congested Hungarian route.

Route planner

Ukraine may need to tap more than one of these routes in order to meet domestic demand in the coming months. The Polish route could deliver only about 1.46bn m³ by the end of October, even if entry flows from Poland hold at maximum capacity until the start of the heating season. Naftogaz predicted in late March that it needs to import about 4.6bn m³ before the start of the heating season, of which just 2.9bn m³ has been contracted, energy minister Herman Halushchenko says.

Ukrainian gas production rebounded in May from April, but output remained below year-earlier levels for a fourth consecutive month, after Russian attacks targeted Ukrainian gas production facilities last winter.

Gas routes to Ukraine *€/MWh*

	Poland-Ukraine	Lithuania-Ukraine	Germany-Ukraine (via Slovakia)	Germany-Ukraine (via Hungary)	Italy-Ukraine (via Slovakia)	Italy-Ukraine (via Hungary)	Greece-Ukraine†
Regasification	1.70	1.20	2.55	2.55	2.10	2.10	1.30
Austria				0.58	0.58	0.58	
Bulgaria							1.29
Czech Rep			0.91				
Germany			0.77	0.77			
Greece							0.60
Hungary				0.86			
Italy					2.09	2.09	
Lithuania		0.62					
Moldova							3.34
Poland	2.64	2.64					
Romania							2.17
Slovakia			2.68		2.68		
Ukraine	1.00	1.00	1.00	1.00	1.00	1.00	2.24
Total fees*	**5.34**	**5.46**	**7.91**	**5.76**	**8.45**	**5.77**	**10.94**

**based on annual fees †before discounts for bundled product are applied*

— TSOs, company presentations, Argus calculations

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MEXICO

Natural gas push falters despite LNG potential

The country's LNG ambitions face geopolitical headwinds owing to its reliance on US gas, writes Antonio Gozain

Mexico's long-standing dependence on US natural gas is facing renewed scrutiny under the administration of President Claudia Sheinbaum, who has pledged to raise domestic output to 5bn ft³/d (52bn m³/yr) by 2030. Yet a combination of financial constraints and regulatory uncertainty suggests the country may struggle to shift its gas strategy in any meaningful way.

At the heart of the challenge is state-owned Pemex, which produced just 4.5bn ft³/d of gas in May — only slightly higher than in previous months and far below the government's target. The firm relies heavily on imports, which hit a six-year high of 1.01bn ft³/d in May. Its lack of progress in reviving gas production hinges partly on Pemex's upstream strategy, which focuses on crude production. "Any peso outside crude is a peso lost," a former energy ministry official tells *Argus*.

Pemex's focus on crude persists even as the global landscape has shifted in favour of gas. International gas and LNG prices have often outpaced crude on an energy-equivalent basis since the 2021–23 energy crisis, yet Pemex has never prioritised gas development. And the fields that Sheinbaum has designated as being gas-rich — including Burgos, Ixachi, Quesqui, Bakte, Lakach and the Cantarell gas cap — face tough challenges. Ixachi and Quesqui are the only two fields producing meaningful quantities at present, having accounted for combined output of about 1.1bn ft³/d in January, the most recent data show. But output expansion is uncertain.

Gas and LNG prices have often outpaced crude on an energy-equivalent basis since the 2021-23 energy crisis, yet Pemex has never prioritised gas development

The Lakach field was once the centerpiece of Pemex's deepwater gas plans but its development is in limbo, despite a partnership with Mexican billionaire Carlos Slim's conglomerate, Grupo Carso. The project's costs are "astronomical" and Slim may walk away if profitability remains elusive, sources close to the deal say.

Elsewhere, Cantarell's gas cap suffers from high nitrogen content that undermines value, while Burgos requires fracking expertise and political backing that Pemex lacks. A $1bn development plan for Bakte has stalled. With Pemex's 2025 upstream budget nearly exhausted by March and suppliers threatening to halt work over unpaid debts, any drilling of new wells appears unlikely.

Private capital could offer relief, but Pemex's new mixed contract model has attracted limited interest. The terms are not commercially attractive and legal uncertainty is only growing, market participants say. And the dissolution of Mexico's energy regulators and overhaul of its judiciary have alarmed investors.

Running out of options

For now, the US is Mexico's only reliable source of gas, covering more than 70pc of domestic demand. State-controlled utility CFE is the main importer, powering most of Mexico's electricity through combined-cycle gas plants. Some policy makers have floated a return to LNG imports, which all but halted after key pipeline connections with the US were completed in 2019. Mexico sourced small amounts of LNG from Indonesia, Peru and Trinidad and Tobago last year, but these totalled less than 1mn t, or 4pc of the country's 17.6mn t/yr of regasification capacity.

Mexico's LNG export ambitions are more advanced but also rely on US gas. US company Sempra's Costa Azul terminal is nearing completion, and compatriot firm New Fortress Energy began shipping from Altamira last year. These projects aim to re-export cheap associated gas produced in the US Permian basin to mainly Asian markets. But such ambitions face geopolitical headwinds. US president Donald Trump's administration could reconsider export permits or pressure Asian buyers to invest directly in US terminals, raising questions about the long-term competitiveness of Mexico-based LNG ventures. Sheinbaum's gas goals may align with energy security and climate ambitions, but without capital, attractive contracts and regulatory clarity, they risk remaining just that — goals.

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GLOBAL LNG

Atlantic basin drives FIDs in LNG capacity in 2025

This year's sanctioned projects will tilt the inter-basin supply balance further towards the Atlantic, writes Evelyn Lee

The Atlantic basin continued to anchor global LNG liquefaction capacity expansion during the first six months of this year, with all export projects that have reached a final investment decision (FID) in 2025 so far located in the basin and US projects accounting for the majority.

Three LNG export projects reached an FID globally over the first half of this year, two of which are in the US and one in Argentina. US producer Cheniere sanctioned 3.3mn t/yr of new capacity at its 17.4mn t/yr Corpus Christi terminal, and it filed an amended application for a 17mn t/yr stage 5 expansion at the 33mn t/yr Sabine Pass facility. The new sanctioned projects will add 19.8mn t/yr of export capacity in the US later this decade and about 6mn t/yr in Argentina by 2028. This marks an increase from last year, when two projects with a combined 12.9mn t/yr of capacity reached an FID worldwide — in Canada and the UAE.

Investment decisions reached in the US this year so far have been long in the making and are unlikely to have materially benefited from the country's political shift stemming from US president Donald Trump's return to the White House. But the attitude of the new administration may help unlock more investment going forward. Trump issued an executive order declaring a national energy emergency on his inauguration day and later proceeded with a swift rollback of regulatory constraints and permitting delays introduced under former president Joe Biden.

One project that may have significantly benefited is the planned 9.5mn t/yr Commonwealth LNG terminal in Louisiana, which had claimed to be close to an FID when Biden introduced such constraints. The project secured its final authorisation from US energy regulator Ferc in June and may proceed to an FID later this year. In contrast, the proposed 20mn t/yr Alaska LNG project, which has been publicly endorsed by Trump on multiple occasions, received a flurry of interest but few firm commitments.

If all sanctioned projects proceed on schedule, Atlantic LNG export capacity will increase by 60pc to about 351mn t/yr by 2030

Elsewhere, Argentina's long-delayed export plan to deploy two floating LNG vessels (FLNGs) by 2028 has made significant progress this year, with the first 5.95mn t/yr project having reached an FID in May. The country also expects to make an FID on its second FLNG project in the second half of this year, adding a 3.5mn t/yr unit to its planned Southern Energy export terminal.

Basin balance

Projects sanctioned this year are set to tilt the inter-basin supply balance further towards the Atlantic market later this decade, despite the bulk of incremental demand growth likely to stem from Asian markets.

If all sanctioned projects proceed on schedule, Atlantic LNG export capacity will increase by 60pc to about 351mn t/yr by 2030 from the operational capacity in 2024, *Argus* estimates. This 131mn t/yr capacity addition in the Atlantic basin far exceeds the Pacific basin's 35pc, or 96.5mn t/yr, scheduled growth by the end of this decade. Based on these projections, Atlantic liquefaction capacity would represent about 48pc of the global total by 2030, up from 44pc in 2024.

The inter-basin supply balance is set to tilt further towards the Atlantic despite sharp planned increases in Pacific basin production, bolstering the Pacific basin's supply outlook. Qatar's proposed 16mn t/yr North Field West expansion plan would raise the country's liquefaction capacity to 142mn t/yr by 2030, state-owned Qatar Energy says. The aggregated figure also reflects the planned 32mn t/yr North Field East and 16mn t/yr North Field South projects, both of which have achieved FIDs. Mozambique's planned 18mn t/yr Rovuma LNG onshore project has not reached an FID, although it is scheduled to be commissioned in 2029.

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IN BRIEF

LNG Canada starts shipments

The 14mn t/yr LNG Canada export terminal loaded its first cargo on 30 June and its second a week later, which market participants see as a sign that it is ramping up production faster than expected.

Egypt charters Energos Winter FSRU for Damietta

Egypt has chartered the 138,000m³ *Energos Winter* floating storage and regasification unit (FSRU) and intends to install the vessel at the port of Damietta. This is the fourth FSRU that Egypt has chartered for use this summer, bringing the country's total regasification capacity to 2.7bn ft³/d (28bn m³/yr).

EU Parliament approves gas storage rules

The European Parliament approved by a large majority an agreement with EU states to revise the bloc's gas storage regulation. The revised regulation extends the EU's existing 90pc storage filling obligation until the end of 2027, but the final legal text allows countries to deviate from the 90pc filling target by up to 10 percentage points in the event of "difficult conditions".

LNG industry urges US Trade Representative to scrap shipbuilding clause

US LNG producers and trade associations have called on the US Trade Representative to remove a protectionist proposal that would punish exporters and shippers that do not export a certain amount of LNG on US-built carriers. The proposed rules would require a set percentage of US LNG exports to be shipped on US-built, flagged and crewed carriers, starting at 1pc in 2028 and rising to 15pc by 2047.

Berlin reduces gas alert level

German economy and energy ministry BMWE has reduced the country's gas alert level, which had been in force since 23 June 2022. The alert is now set as "early warning level", because the risk of a strained gas supply is deemed to be low at present, regulator Bnetza says. "Gas supply in Germany is stable" and security of supply is guaranteed, it says.

Russian Gazprom's board approves new strategy

Russian state-controlled Gazprom's board of directors has approved a long-term development strategy for the company for 2026–35, with a strong focus on diversifying gas export markets. The plan also targets increased domestic gas sales, expanded gas processing capacity, higher LNG production and reduced investment in non-core businesses. The company has not yet disclosed further details.

Thailand's appetite for spot LNG to decline

Thailand's spot LNG demand for power generation may decline in the coming years, as the country is mulling more term deals and overall gas demand is set to fall. Thailand's share of imported LNG in its gas supply mix is expected to grow, but several recently signed term deals will limit Thai importers' interest in spot supply.

US' EQT to 'limit' hedged gas output to 50pc

The US' second-largest gas producer by volume, EQT, plans to use financial derivatives to lock in prices for no more than half of its output in the coming years, in contrast with previous years when it hedged most of its supply. EQT would need to have "conviction" on its outlook for US gas prices in order for it to hedge a full 50pc of its production, chief executive Toby Rice tells *Argus*. The firm remains entirely unhedged for 2026, Rice says.

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GLOBAL GAS MARKET OVERVIEW

KEY PRICE MOVEMENTS

- The front-month contract at the Dutch TTF gas hub declined to $11.60/mn Btu on 7 July from $13.63/mn Btu two weeks earlier

- The Argus Northeast Asia (ANEA) des price for delivery in the first half of August fell to $12.41/mn Btu from $14.10/mn Btu over the same period

- The Argus Round Voyage spot rate for cross-basin charters (ARV3) edged lower to $27,000/d from $29,000/d over the past fortnight

- Nymex futures for delivery at the Henry Hub dropped to $3.41/mn Btu from $3.70/mn Btu

Inter-basin arbitrage closes

The differential between LNG delivered prices in Europe and Asia-Pacific narrowed enough over the past two weeks to remove the incentive for uncommitted Atlantic basin cargoes to take the longer route to Asia-Pacific, as the European stockbuild remained the main demand driver in global LNG.

Northwest European des prices for August fell to $11.18/mn Btu on 7 July from $13.41/mn Btu on 23 June. But the bulk of this decrease took place on 24 June following the ceasefire between Israel and Iran. The conflict had stoked fears about potential disruptions to LNG flows through the strait of Hormuz. LNG prices for delivery to Europe have remained within a $11-12/mn Btu range since then. The ANEA price — the *Argus* assessment for LNG deliveries to northeast Asian markets — was also on a downward trajectory over the past two weeks, falling to about $12/mn Btu from above $14/mn Btu.

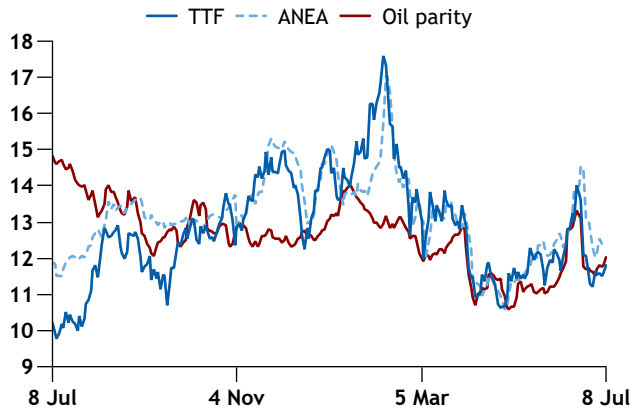
This caused the inter-basin arbitrage to remain mostly closed over the past fortnight, in contrast with the previous period, when concerns of potential disruptions to Middle Eastern supplies were strongest for Asian markets that are heavily reliant on Qatari LNG in particular. Asian des prices later found some support at about the mid-$12s/mn Btu, mostly because some spot demand materialised from Bangladesh, India and parts of southeast Asia. But spot interest from northeast Asian importers remained conspicuously absent.

The start-up of the 14mn t/yr LNG Canada project at the turn of the month will also alter the supply-demand balance between the Atlantic and Pacific basins, with the additional supply available to Asian markets set to weigh further on inter-basin competition this year.

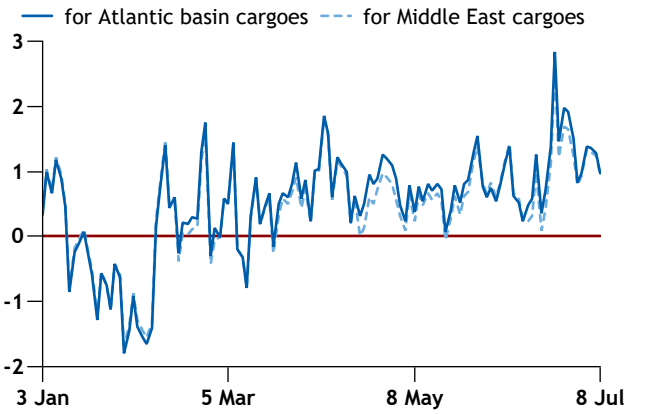
Charter rates continued to rise despite the removal of risk premiums related to the conflict in the Middle East. Spot charter rates for cross-basin voyages for two-stroke vessels grew sharply in late June, with a combination of an open inter-basin arbitrage and tight availability for late-July loadings compounding the risk premium linked to the conflict in the Middle East. And charter rates have not fallen significantly since then, helping to keep the arbitrage closed.

In the US, natural gas futures have decreased in recent days owing to high inventories and forecasts of slightly milder weather. Nymex gas for August delivery at the Henry Hub dropped by 7.2¢/mn Btu, or 2.1pc, to settle at $3.34/mn Btu on 8 July — the lowest since 26 June. US gas inventories have grown by 1.26 trillion ft³ (36bn m³) since the start of storage injections in March, or 47pc larger than the five-year-average build for this period of 852bn ft³, according to US government agency the EIA.

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

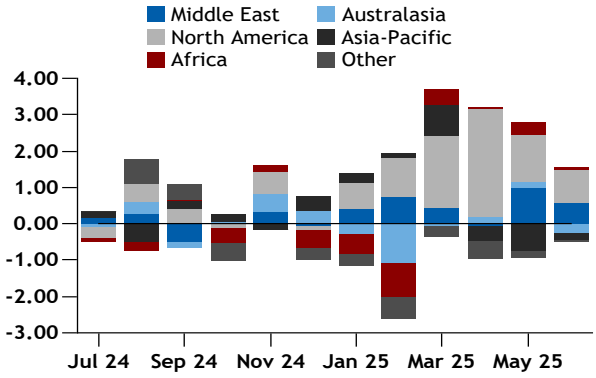
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LNG TRADE FLOWS

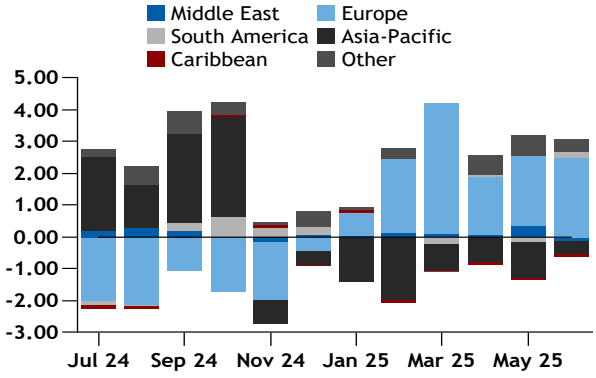
LNG exports, yoy change

mn t



LNG imports by region, yoy change

mn t



Europe drives rise in global LNG receipts

Global LNG imports rose on the year in June, as strong deliveries to Europe offset muted demand from China and India.

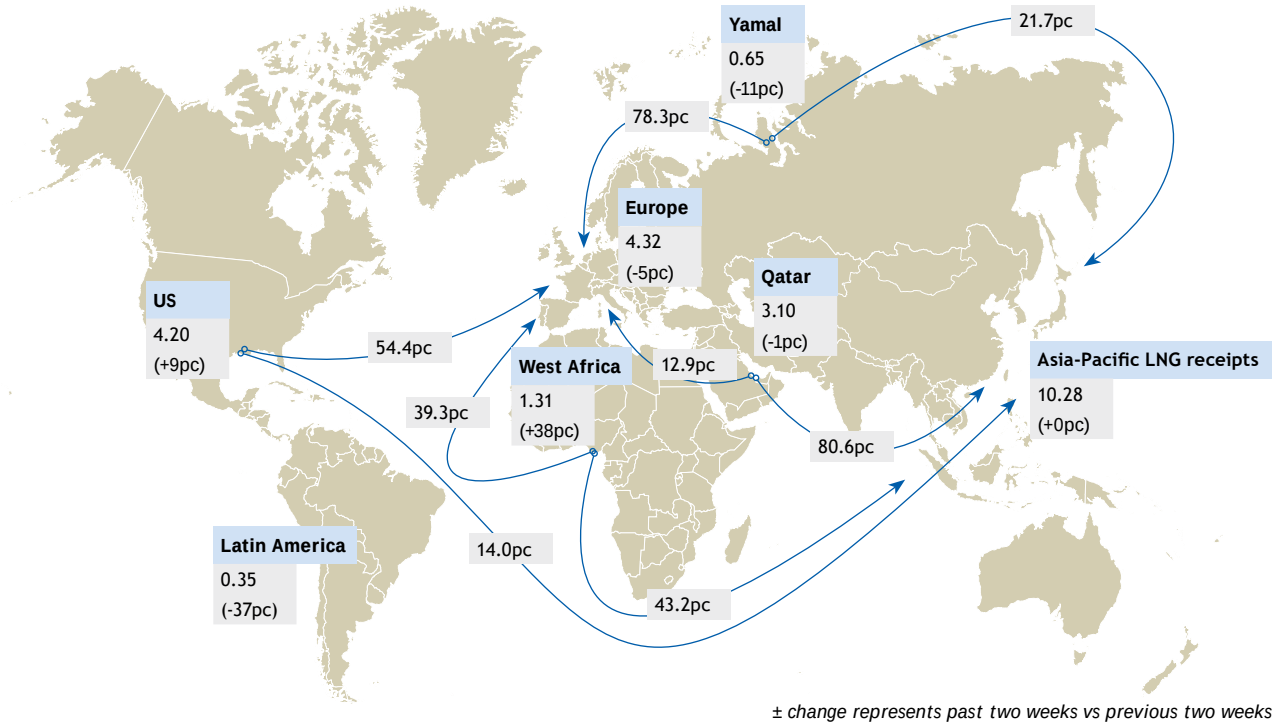
Combined global LNG imports grew to 33.1mn t in June from 31.3mn t a year earlier, preliminary figures from trade analytics firm Kpler show. Europe's LNG receipts rose to 9.71mn t from 7.2mn t, as subdued Asian buying and stronger European injections held the inter-basin arbitrage for uncommitted US loadings closed for most of May. European injections were higher than a year earlier as the region ended winter with lower stocks and is receiving less Russian gas than in 2024 after transit flows through Ukraine halted on 1 January.

Italian imports rose to 1.49mn t from 649,000t, setting a new monthly record. The Italian PSV gas hub's premium to the Dutch TTF and Spanish PVB probably spurred the firm deliveries, also supported by the start-up of the 3.8mn t/yr Ravenna terminal, which took two cargoes in June. Dutch receipts rose to 1.61mn t from 1.19mn t. Record sendout from the country's LNG terminals last month, at 771 GWh/d, allowed net storage injections to average 575 GWh/d, more than double the 222 GWh/d of a year earlier.

Asian imports fell to 21.7mn t last month from 22.6mn t in June 2024, largely because the early onset of the monsoon season capped demand for early-summer LNG imports. Gas-fired generation in south and southeast Asia was lower than average in June because the region's wet season arrived about two weeks earlier than usual, which boosted hydropower generation. India imported 2.12mn t of LNG in June, down from 2.6mn t a year earlier.

Latest estimated gas imports and exports

mn t



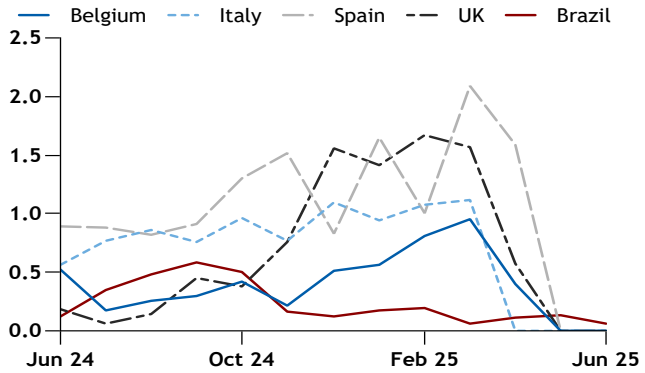
± change represents past two weeks vs previous two weeks

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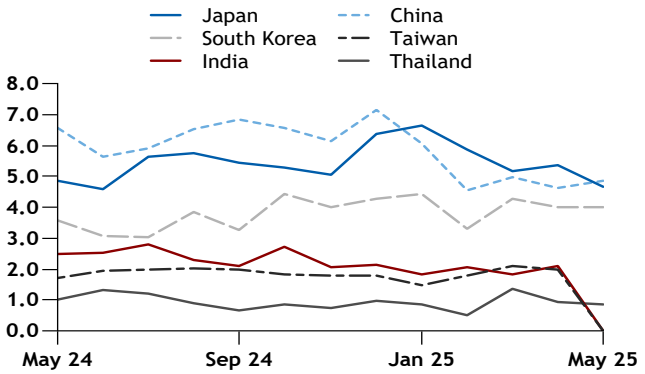
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LNG TRADE FLOWS

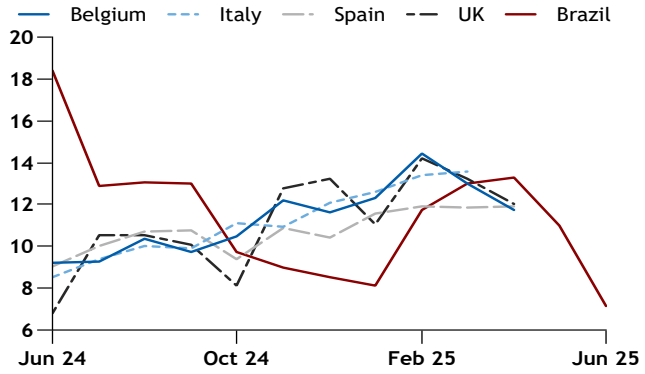
Atlantic basin LNG import volumes (customs data) *mn t*



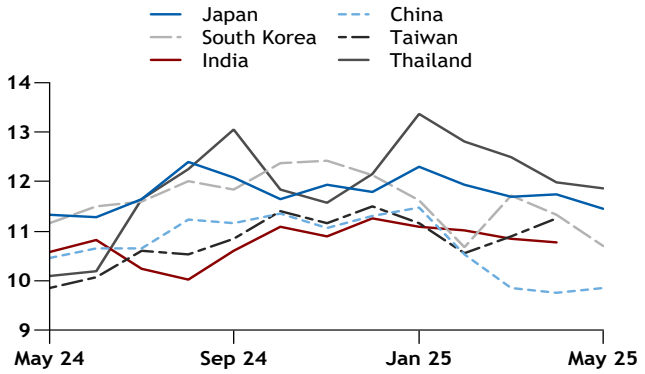
Asia-Pacific LNG import volumes (customs data) *mn t*



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



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



Declared LNG import volumes *'000t*

Importer	Jan	Feb	Mar	Apr	May	Jun
Northest Asia						
China	6,059	4,537	4,966	4,637	4,843	0
Japan	6,641	5,875	5,151	5,374	4,664	0
South Korea	4,422	3,313	4,254	3,993	4,008	0
Taiwan	1,484	1,802	2,088	1,982	0	0
South and southeast Asia						
India	1,838	2,047	1,809	2,097	0	0
Pakistan	661	597	481	486	663	548
Bangladesh	0	0	0	0	0	0
Thailand	839	492	1,378	917	846	0
Europe						
UK	1,412	1,671	1,563	572	0	0
Netherlands	1,009	963	1,228	1,474	0	0
Belgium	560	808	953	401	0	0
Germany	302	272	219	563	0	0
Poland	0	0	0	0	0	0
Lithuania	0	0	0	0	0	0
France	0	0	0	0	0	0
Spain	1,645	999	2,090	1,593	0	0
Portugal	217	280	216	143	0	0
Italy	944	1,075	1,120	0	0	0
Croatia	192	124	133	128	0	0
Greece	211	360	283	78	0	0
Turkey	0	0	0	0	0	0
Latin America						
Brazil	171	194	60	110	136	60
Argentina	0	0	0	42	40	0
Chile	189	100	104	275	167	0

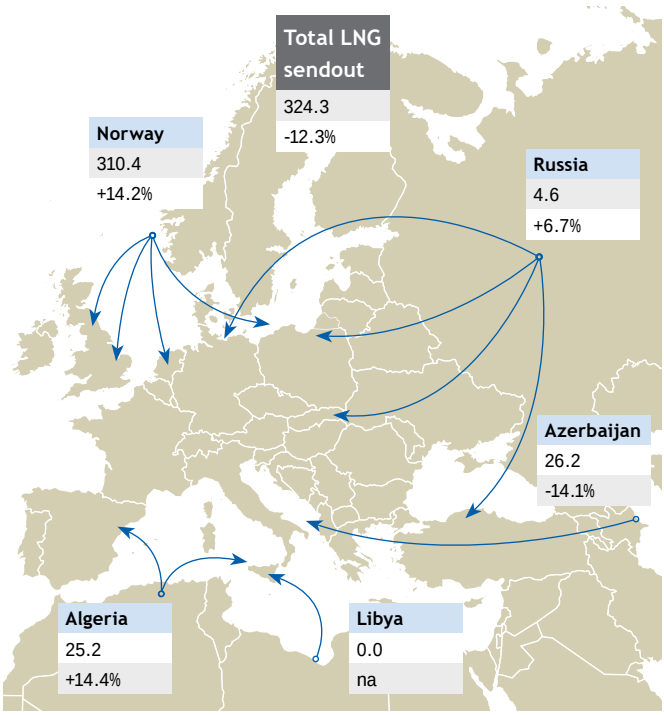
Declared LNG import prices *$/mn Btu*

Importer	Jan	Feb	Mar	Apr	May	Jun
Northest Asia						
China	11.48	10.52	9.86	9.75	9.84	
Japan	12.30	11.93	11.68	11.75	11.46	
South Korea	11.62	10.67	11.73	11.34	10.69	
Taiwan	11.16	10.55	10.90	11.26		
South and southeast Asia						
India	11.09	11.01	10.85	10.76		
Pakistan	9.05	9.15	8.98	9.27	8.47	8.47
Bangladesh						
Thailand	13.38	12.81	12.50	11.99	11.87	
Europe						
UK	11.04	14.19	13.21	12.01		
Netherlands	12.88	13.65	12.95	13.48		
Belgium	12.33	14.44	13.01	11.74		
Germany	13.14	14.80	11.38	12.83		
Poland						
Lithuania						
France						
Spain	11.55	11.92	11.83	11.89		
Portugal	7.02	11.92	7.37	9.50		
Italy	12.59	13.39	13.55			
Croatia	13.27	13.69	15.73	13.13		
Greece	13.65	13.77	15.30	15.93		
Turkey						
Latin America						
Brazil	8.11	11.75	12.98	13.29	10.98	7.16
Argentina				12.99	12.03	
Chile	8.38	7.70	6.93	7.86	7.93	

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EUROPE

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



Injections hold strong on firm supply

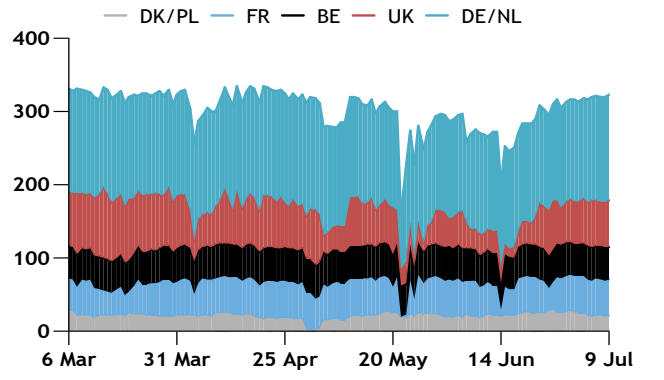
Abundant supply supported the European stockbuild in recent weeks, despite stronger-than-average power-sector gas burn.

EU injections averaged 3.6 TWh/d over the past two weeks, about 15pc higher than the three-year average for the period of 3.4 TWh/d. June injections were also firm at nearly 4 TWh/d, up from 3.3 TWh/d in the same month of 2022-24. The stockbuild has remained high in recent weeks, owing largely to strong LNG deliveries. Sendout across the bloc averaged 3.9 TWh/d over the past two weeks, up significantly from a three-year average of 3.3 TWh/d.

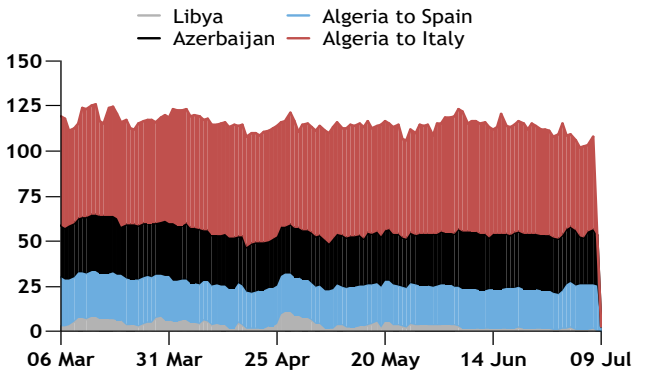
High European delivered prices during the brief war between Iran and Israel helped keep the inter-basin arbitrage for uncommitted US fob supply closed in June. Low Asian demand and higher freight rates also encouraged firms to send Atlantic basin cargoes to Europe ahead of Asia-Pacific, after front-month European hub prices fell back to where they were before the conflict started.

Injections were high despite a heatwave in late June-early July that pushed up power-sector gas burn in southern Europe, where use of air conditioning is widespread. Gas burn for power generation across the bloc's 12 largest consumers stood at 5.9 TWh/d on 24 June-7 July, owing largely to particularly strong demand from Spanish and Italian combined-

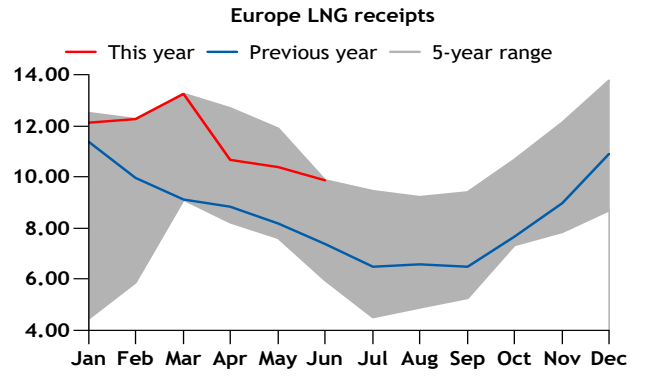
Norway pipeline supply to EU *mn m³/d*



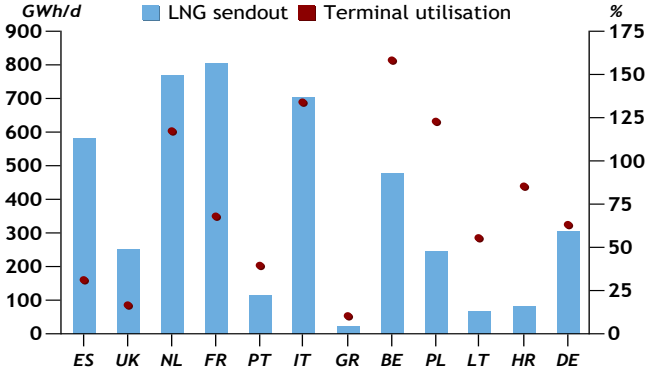
Supply to EU from southern routes *mn m³/d*



Europe LNG seasonality chart *mn t*



LNG sendout and terminal utilisation

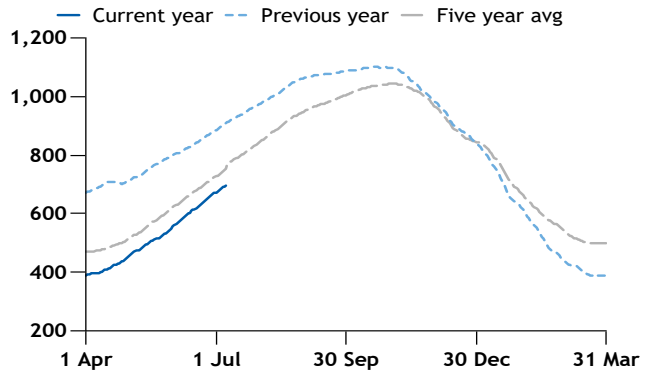


In the first half of the month the graph will show the figures for the full previous month, whereas in the second half of the month the graph will show month-to-date figures

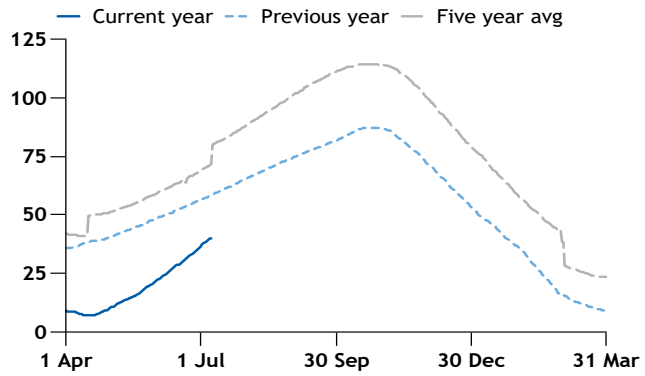
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EUROPE

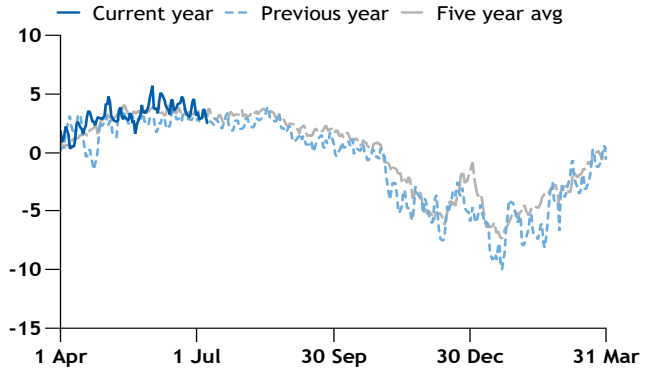
Total EU + UK gas stocks *TWh*



Ukraine stocks *TWh*



EU + UK storage movements *GWh/d*

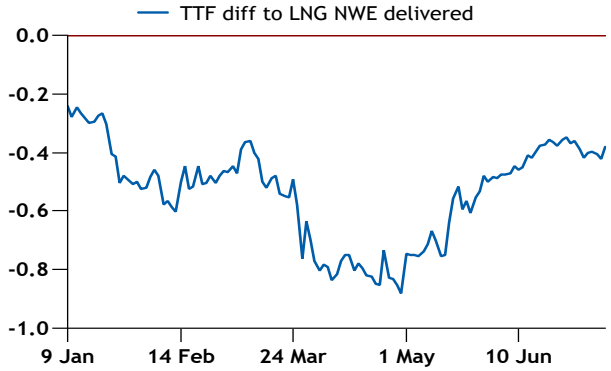


cycle gas turbines (CCGTs). But this hefty consumption barely affected Spanish injections. Spain ramped up imports from France across the Pirineos interconnector to meet stronger CCGT gas demand, in turn curbing available supply for injections elsewhere. The Italian stockbuild slowed a two-month low in late June because of stronger power-sector gas burn and despite record-high LNG sendout.

Looking ahead, new underground storage capacity bookings across German sites — which had previously struggled to allocate capacity because there was limited price incentive — suggest interest in filling capacity at less attractive storage sites is growing, even slow-cycling sites, at which capacity holders are unable to capitalise on short-term price movements. German gas storage operator Sefe sold 3.9TWh of capacity out of the 5TWh it offered at its 45TWh slow-cycling Rehden site on 8 July. And German gas storage operator VNG held a successful auction for its Katharina facility on 8 July, selling all of the 1.28TWh of gas storage space with interruptible withdrawal capacity on offer.

But these capacity bookings heightened expectations of stronger injection demand in the short term, pushing up TTF and THE balance-of-summer prices by the close of 8 July. This shrunk their discounts to the corresponding front-winter contracts, capping the injection incentive again and compromising the success of Sefe's Rehden capacity auction on 9 July. The auction failed to sell any of the 5TWh of capacity on offer.

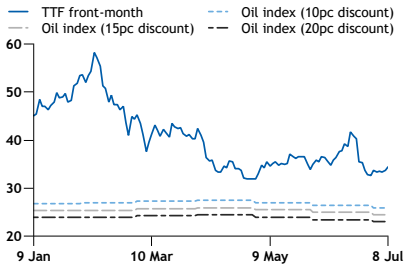
NW Europe LNG des-TTF spread *$/mn Btu*



Aggregate EU, UK and Ukraine inventories and storage movements *TWh*

Month	Initial stocks	% of capacity	Net withdrawals (injections)	1 year earlier	5-year average
Feb 25	648	43.9	5,408.0	861	1,366.9
Mar 25	457	31.0	1,962.4	761	1,357.7
Apr 25	399	27.4	-1,818.7	709	1,347.7
May 25	464	31.8	-3,518.6	753	1,337.6
Jun 25	579	39.5	-4,021.7	849	1,326.5
Jul 25	710	48.4	-962.3	942	1,316.0

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



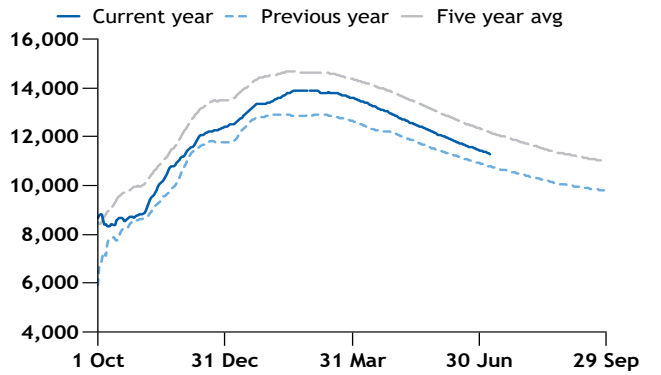
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EUROPE

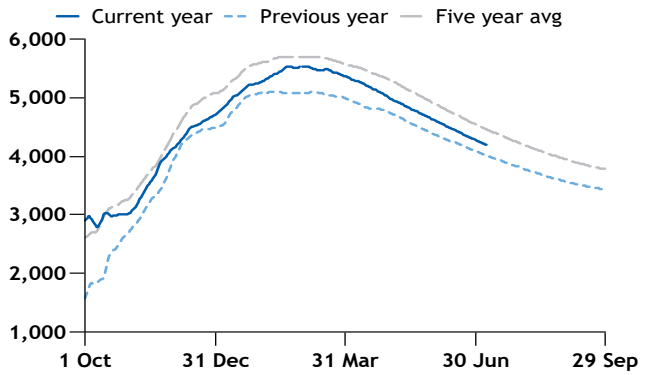
European demand by country, month to date										GWh/d
	Belgium	France	Germany	Italy	Netherlands	Poland	Portugal	Spain	UK	Total
Local distribution	79.6	0.0	198.3	297.9	133.3	229.8	49.3	na	511.8	**1,500.0**
Industrial	101.5	0.0	na	336.4	na	125.0	20.0	na	29.6	**612.4**
Power sector	76.0	0.0	na	866.4	na	na	42.5	362.5	252.8	**1,600.1**
Total consumption	**257.0**	**0.0**	**1,193.9**	**3,001.4**	**516.5**	**354.8**	**111.8**	**1,309.0**	**794.2**	**7,538.5**
±% year earlier	**7.7**	**-100.0**	**-5.2**	**8.2**	**0.2**	**-3.1**	**15.3**	**17.1**	**-12.8**	**-7.5**

Aggregate demand GWh/d



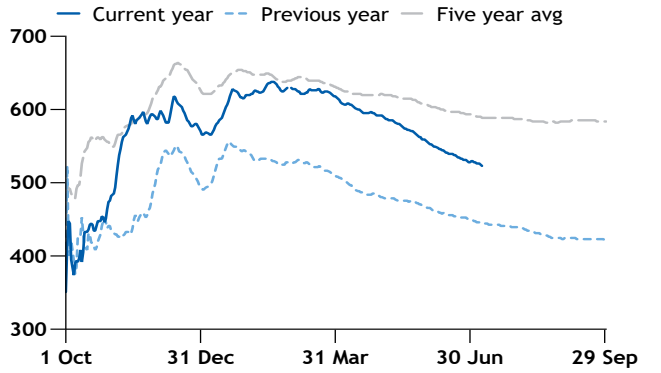
includes data on Spain, UK, Netherlands, France, Portugal, Italy, Poland, Germany, Romania, Hungary, Czech Republic, Belgium, Bulgaria, Croatia

LDZ demand GWh/d



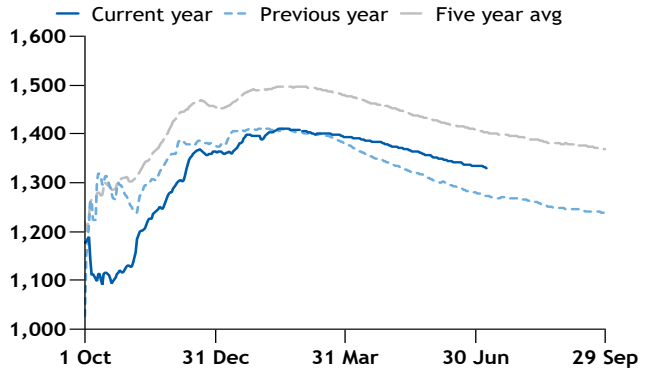
includes data on UK, Netherlands, France, Portugal, Italy, Poland, Germany, Romania, Belgium, Hungary

Power sector gas demand GWh/d



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

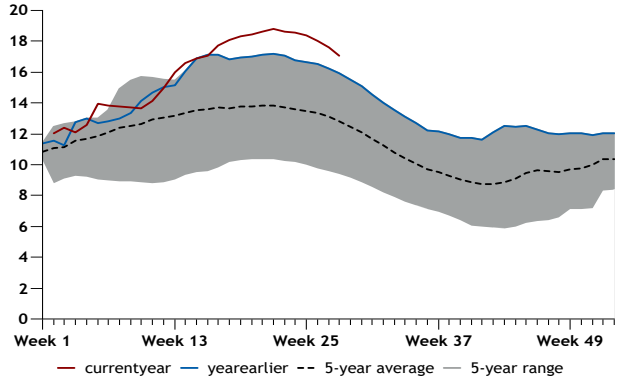
Industrial demand GWh/d



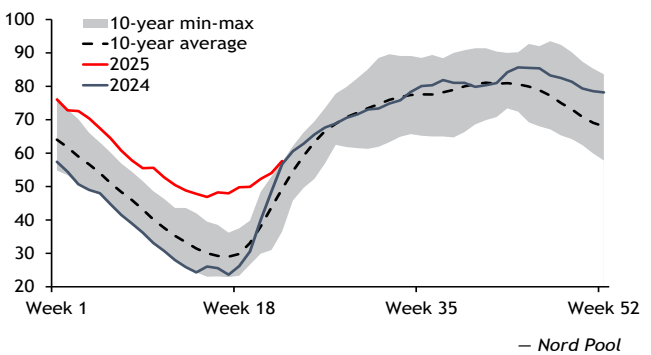
includes data on UK, France, Italy, Portugal, Belgium, Poland

Click here to download European gas demand data

Spanish hydroelectric stocks TWh



Nordic hydroelectric stocks GWh



— Nord Pool

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EUROPE

HIGHLIGHTS

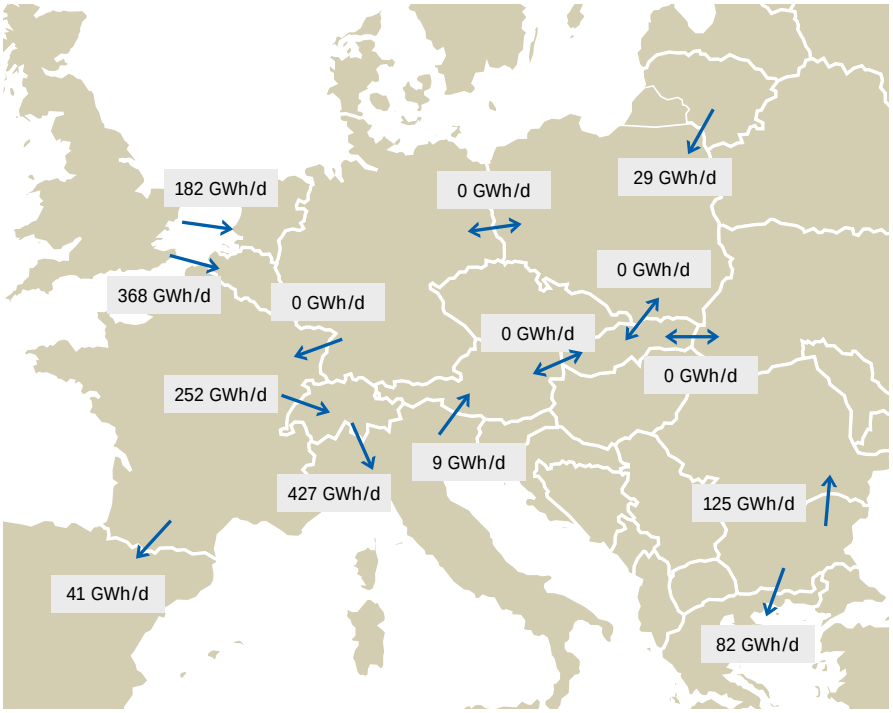
• Spain ramped up its imports from France at the Pirineos interconnector on the back of stronger cooling-related power-sector gas burn

• Belgium switched to net exports to France at the Virtualys point on four days in July, for the first time since December

• Norwegian gas inflows at the Dunquerke point stepped up to balance out lower LNG sendout from the Fos Cavou terminal

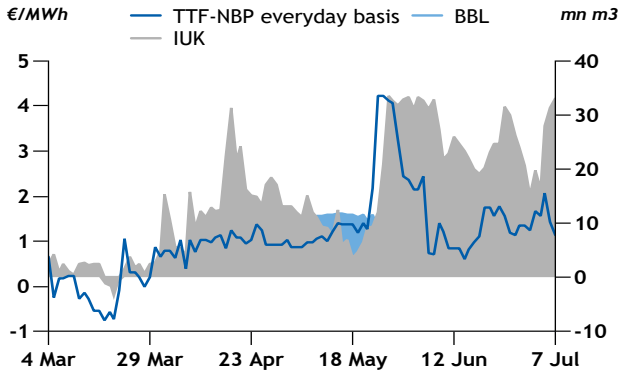
• German exports to the Czech Republic at the Brandov virtual interconnection point in early July were at their highest since November 2022

Cross-border flows (month to date)



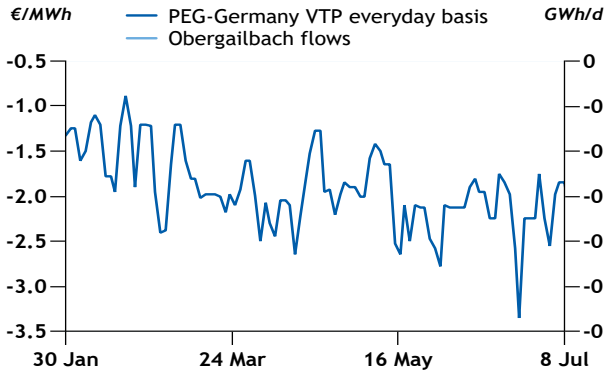
UK-EU gas flows

mn m³



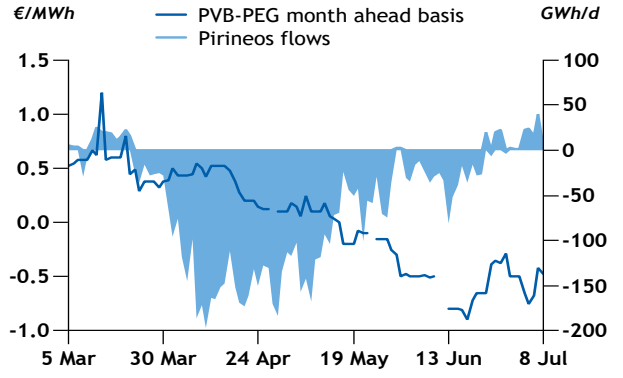
Germany-France gas flows

GWh/d



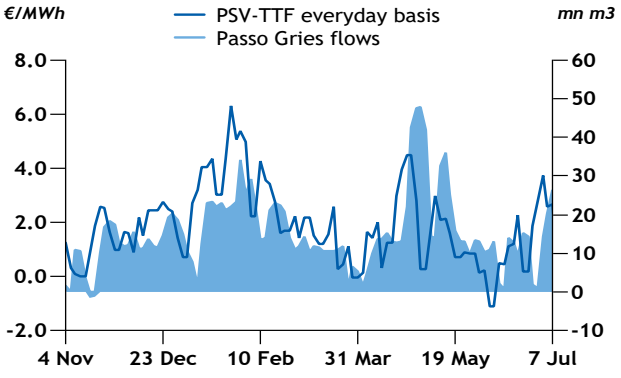
France-Spain gas flows

GWh/d



Switzerland-Italy gas flows

mn m³

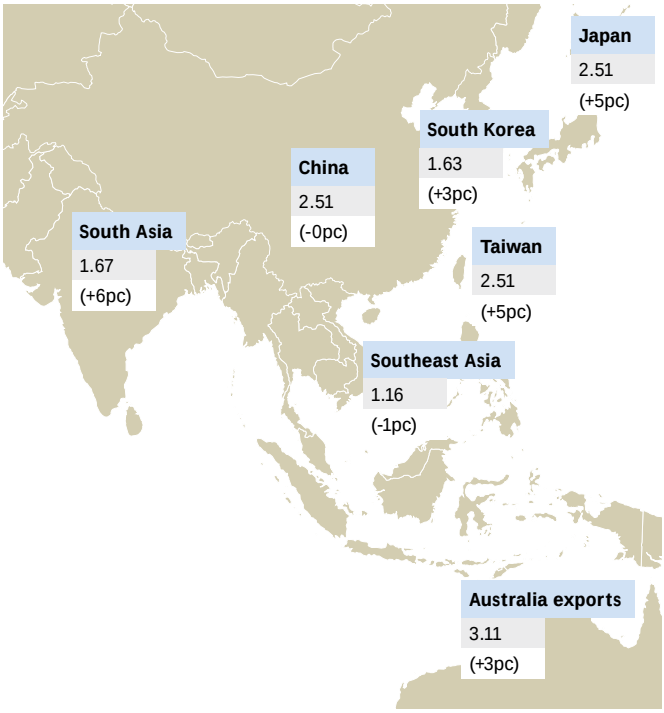


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ASIA-PACIFIC

LNG deliveries to Asia-Pacific

mn t



Heatwave eats into Japanese LNG stocks

LNG inventories at Japan's main power utilities fell for a second consecutive week in the week to 6 July, as hotter-than-normal weather boosted electricity demand for cooling and increased gas-fired power generation.

Japanese utilities held 2mn t of LNG on 6 July, down by 7pc from a week earlier and 12pc lower than the 22 June high of 2.27mn t, according to a weekly survey by trade and industry ministry Meti. But stocks on 6 July were nearly in line with the 1.99mn t recorded for 7 July 2024.

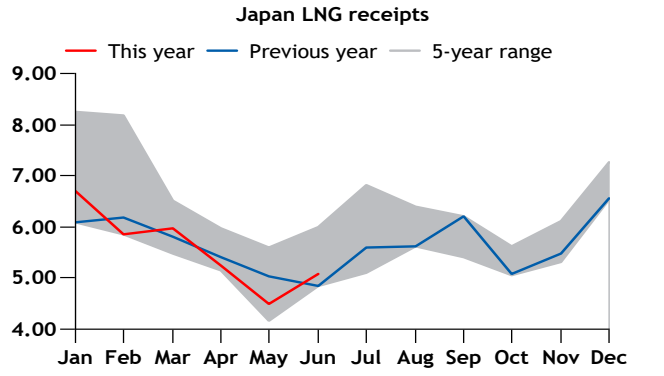
Much of Japan has experienced unusually hot weather since the middle of June. This boosted the country's power demand to an average of 113GW from 30 June-6 July, up by 10pc on the week and by 7pc from a year earlier, according to nationwide transmission system operator Occto.

Firm power demand prompted utilities to raise gas-fired output by 9.1pc on the week to an average of 36GW in the week to 6 July, Occto data show. Coal and oil-fired output increased by 22pc to 31GW and by 49pc to 1GW, respectively.

Higher power prices boosted margins for gas-fired plants. Spark spreads for 58pc-efficient gas-fired units running on spot LNG averaged ¥2.82/kWh ($19.18/MWh) over 30 June-6 July, up from ¥0.88/KWh a week earlier, based on *Argus* LNG and Japan Electric Power Exchange power prices.

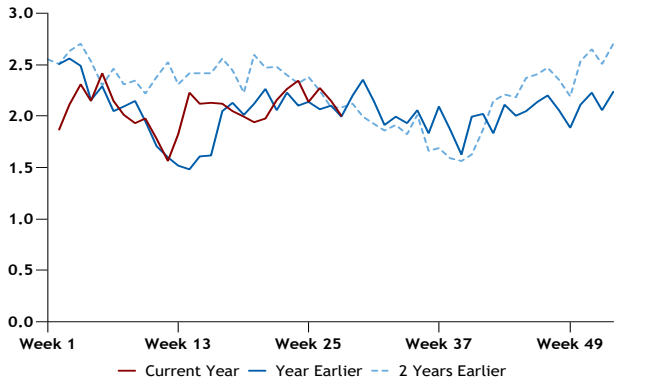
Japan seasonality chart

mn t



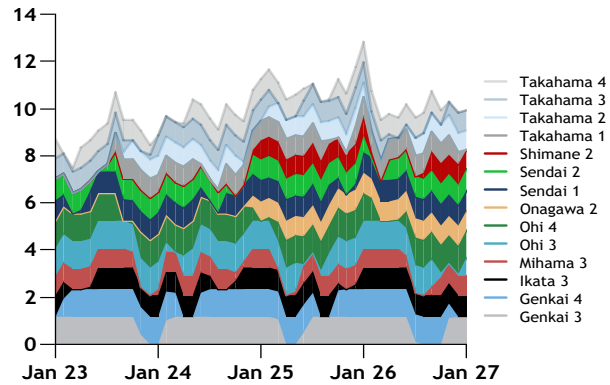
Japanese LNG stocks

mn t



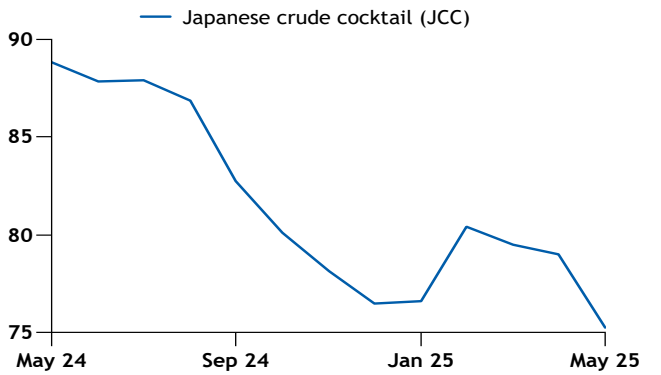
Japan nuclear availability

GW



Japanese Crude Cocktail (JCC)

$/bl

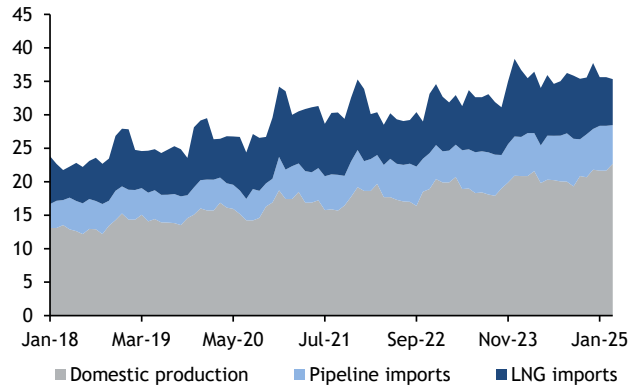


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ASIA-PACIFIC

China supply balance

bn m³



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

Chinese LNG receipts remain lower

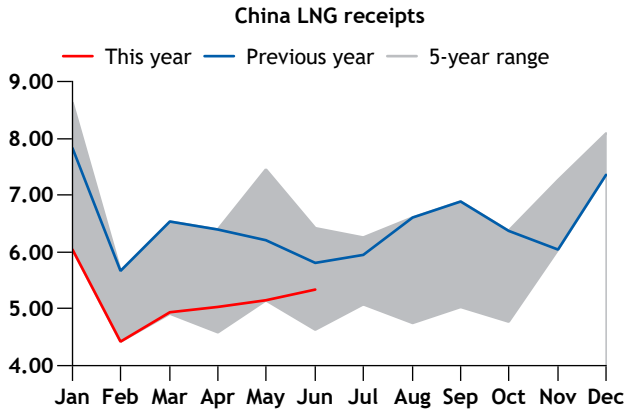
LNG deliveries to China in June fell on the year for an eight consecutive month, extending a trend likely to have been driven by continued growth in domestic production and pipeline imports alongside lower donwstream demand.

China received 5.24mn t of LNG in June, down from 5.70mn t a year earlier, preliminary ship-tracking figures from analytics firm Vortexa show. LNG deliveries have been lower on the year every month since November. This may be a result of reduced downstream demand, although this appeared to rebound in May. Heavy rainfall in south China, where cooling demand is stronger, is likely to have weighed on power-sector gas burn.

Steady growth in Russian gas imports through the 38bn m³/yr Power of Siberia pipeline may have sapped LNG demand further, although figures released by state-controlled Gazprom suggest flows are on course to fall short of contractual obligations this year. *Argus* estimates supplies of just under 16bn m³ from the start of this year to mid-June, based on Gazprom statements and earlier company data.

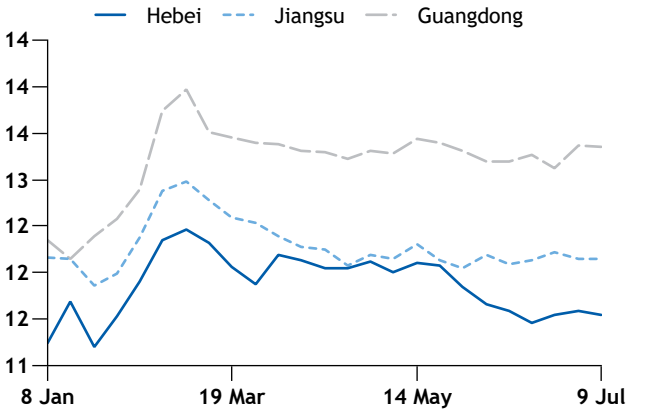
China LNG seasonality chart

mn t



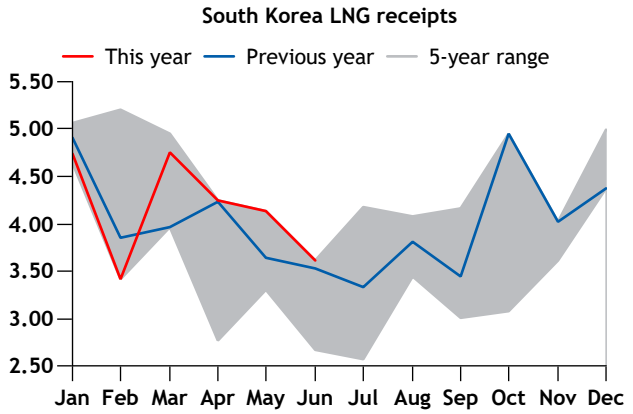
China domestic trucked LNG price

$/mn Btu



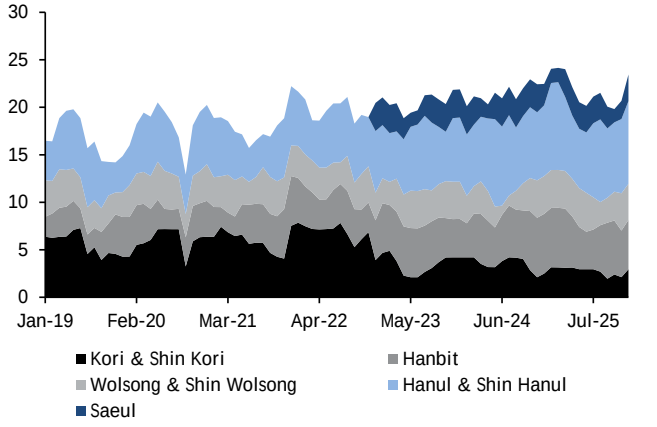
South Korea LNG seasonality chart

mn t



South Korea nuclear availability

GW

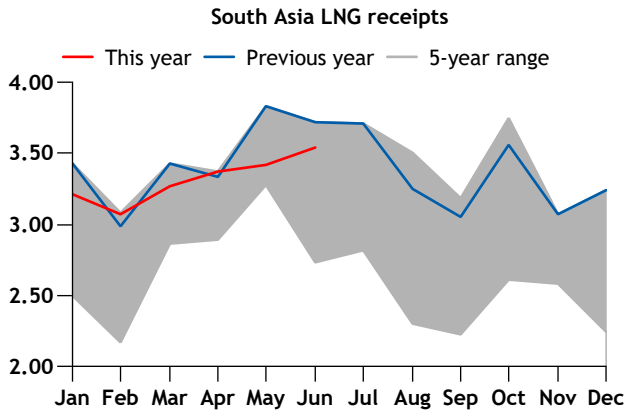


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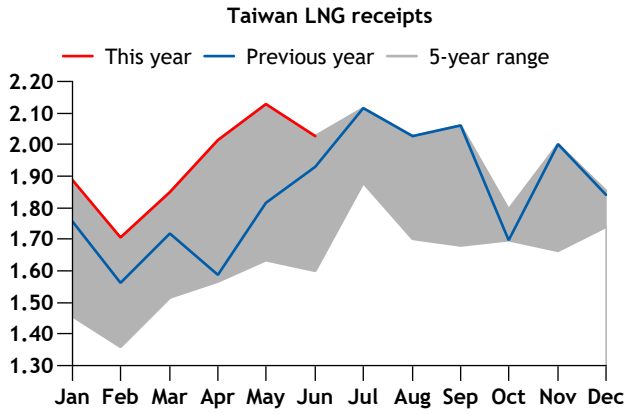
South Asia LNG seasonality chart

mn t



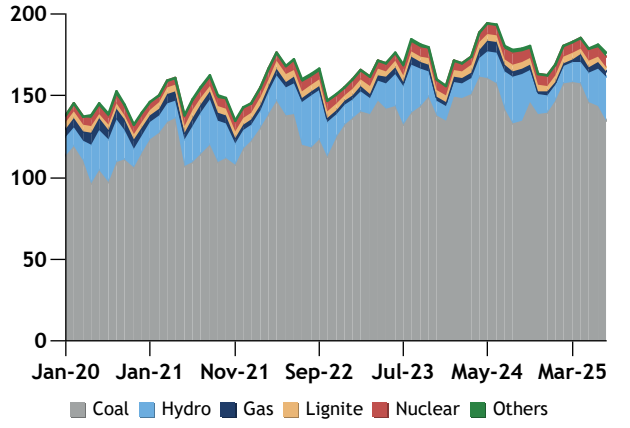
Taiwan LNG seasonality chart

mn t



India power generation mix

TWh



Vietnam LNG-fired plant connects to grid

Vietnam's second LNG-fired power plant, Nhon Trach 4, connected to the country's power grid late last month, according to state-owned operator PV Power.

The firm finished connecting Nhon Trach 4 to the national grid on 27 June at an initial capacity of 50MW, PV Power says. The facility was first brought on line on 6 June, with the firm aiming to start commercial operations in November.

The 812MW Nhon Trach 3, the country's first LNG-fired plant, was connected to the grid on 5 February, with commercial operations planned for mid-August. This suggests a two-month delay from the previous planned date of commercial operations on 6 June, which had already been postponed from May. Nhon Trach 3 generated 812MWh of electricity in April, having been on line for 30 hours "stably" in base power mode, according to PV Power.

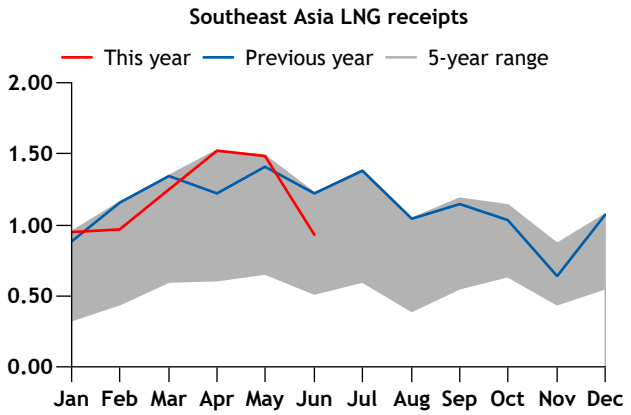
The Nhon Trach units have a combined capacity of about 1.5GW, which may consume up to 800,000 t/yr of LNG, assuming a 55pc efficiency rate and 50pc utilisation rate. The plants could boost Vietnam's LNG receipts when they are fully operational. The country imported 223,900t of LNG in the first six months of this year, down from 259,300t a year earlier, according to data from ship-tracking firm Vortexa.

Vietnam produced 156TWh of electricity in the first six months of 2025, up by 3pc from the same period in 2024, according to preliminary statistics from the country's electricity regulator. Despite the small increase, combined demand in Vietnam fell short of expectations owing to milder-than-usual weather, the regulator says. Maximum temperatures in Hanoi averaged about 0.3°C less than seasonal norms over January-June.

But gas consumption has remained steady this year so far, data from PV Gas show. Vietnam's southeast and southwest regions used 3.3mn m³/d and 8mn m³/d, respectively, from January-May, in line with the previous year.

Southeast Asia LNG seasonality chart

mn t

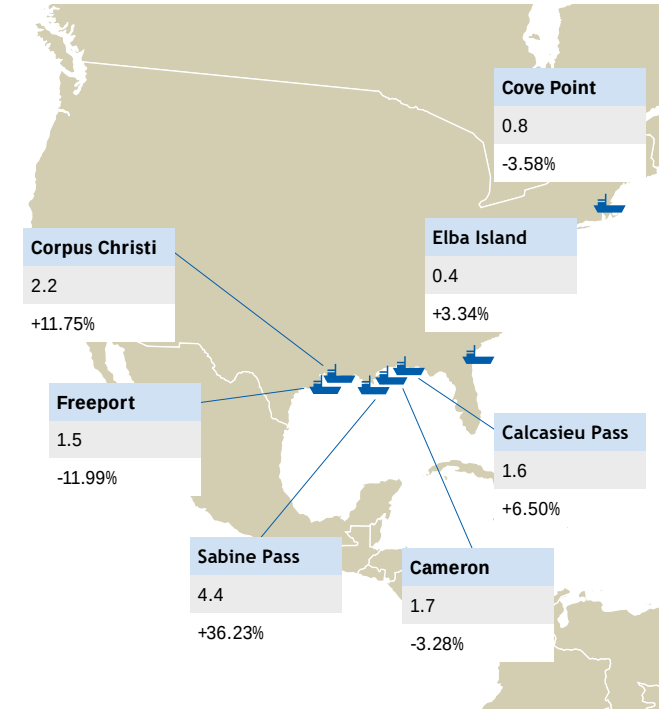


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Feedgas flows to US LNG terminals

trillion Btu/d



EIA trims Henry Hub outlook for 2025-26

US government agency the EIA has cut its expectations for average natural gas prices in the US by 7.5pc for this year and by 10pc for next year, as mild weather from late April-early June resulted in high injections into gas storage.

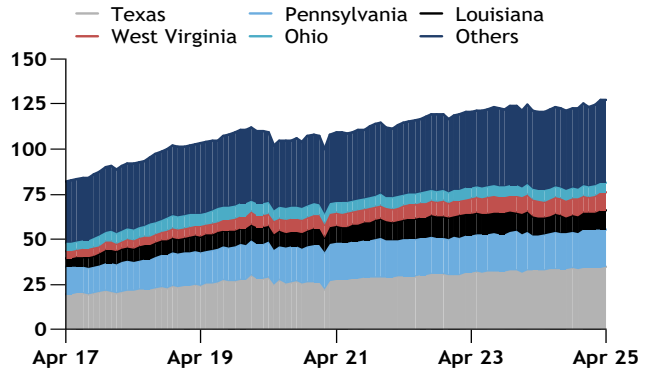
Gas prices at US benchmark the Henry Hub are expected to average $3.70/mn Btu in 2025 and $4.40/mn Btu in 2026, the EIA said in its monthly *Short-Term Energy Outlook*. These projections are lower than its previous forecasts of $4.00/mn Btu for this year and $4.90/mn Btu for next year.

The downward revisions follow several weeks of low cooling demand and larger-than-average storage injections. These factors also prompted the EIA to revise up its projection for end-of-summer inventories to 3.91 trillion ft³ (111bn m³) — 3pc higher than the five-year average and a reversal of previous months' forecasts, when it consistently expected below-average end-of-summer inventories.

Low stocks earlier this year supported gas prices, in turn incentivising production, which rose by 4pc on the year to 116.8bn ft³/d in the second quarter. The EIA expects marketed production to be steady at 116bn ft³/d in 2025-26, with output growth in the Permian basin and Appalachian region merely offsetting declines in the rest of the US. Production averaged 113.2bn ft³/d last year.

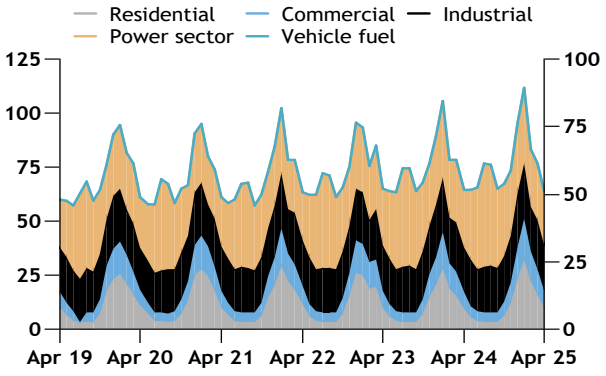
US production

bn ft³/d



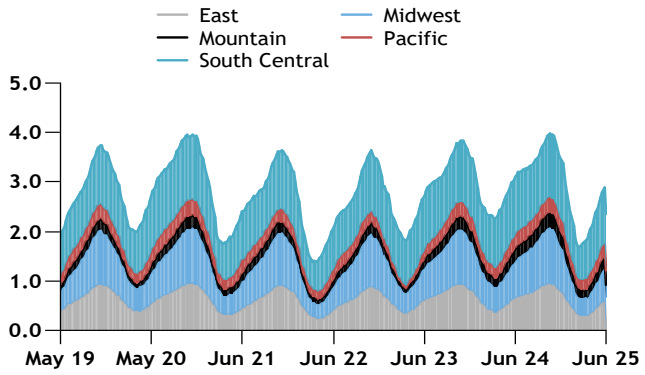
US demand

bn ft³/d



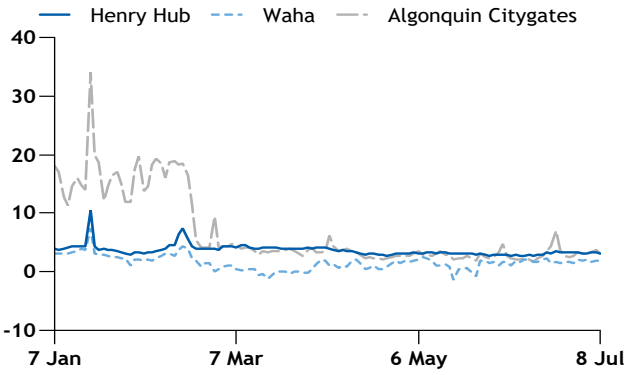
US stocks

trillion ft³



US domestic gas prices

$/mn Btu

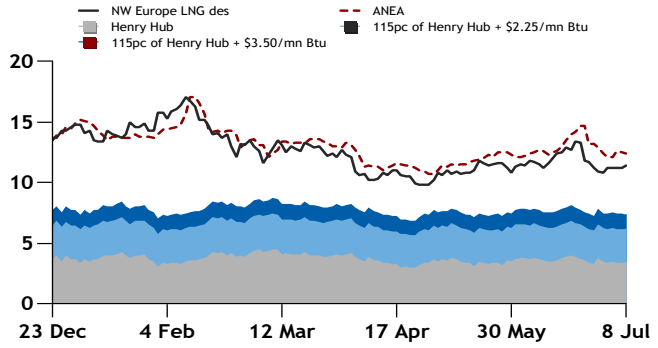


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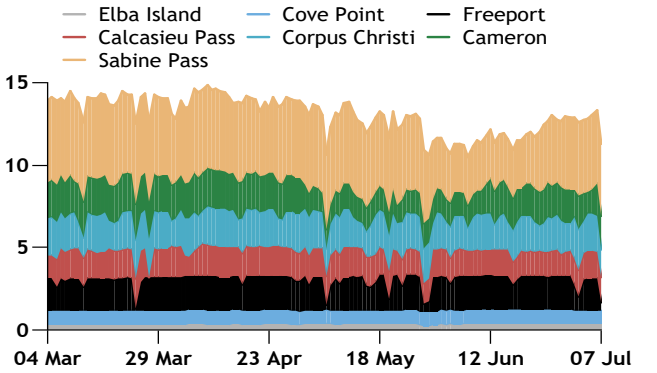
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US storage movements, stocks							*bn ft³*
Region	**27 Jun**	**20 Jun**	**Implied flow**	**Year ago (21 Jun)**	**% change**	**Five-year average (20-25)**	**% change**
East	0	589	-589	646	-100.0	579	-100.0
Midwest	688	665	23	758	-9.2	672	2.4
Mountain	228	223	5	236	-3.4	177	28.8
Pacific	287	281	6	283	1.4	254	13.0
South Central	1,148	1,140	8	1,178	-2.5	1,083	6.0
Total	**2,953**	**2,898**	**55**	**3,102**	**-4.8**	**2,765**	**6.8**

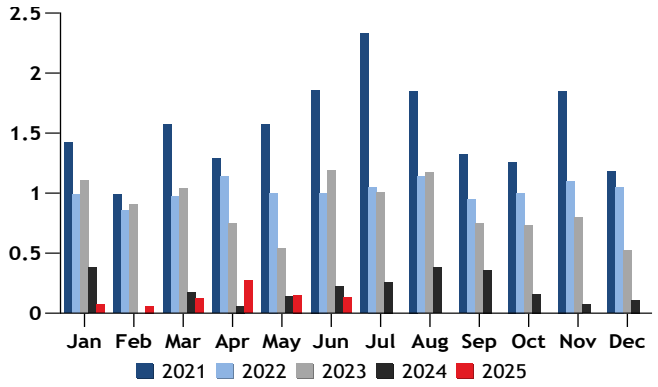
US long-term fob vs Europe, Asia spot des prices *$/mn Btu*



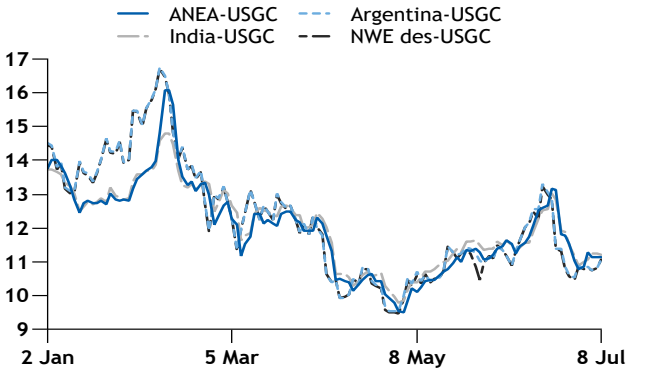
Feedgas flows to LNG plants *trillion Btu*



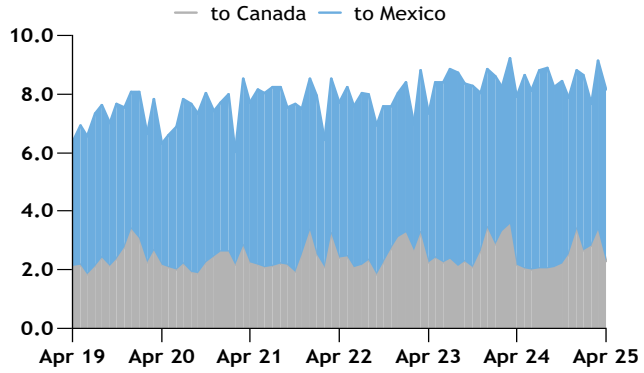
LNG tankers transiting Panama Canal *mn t*



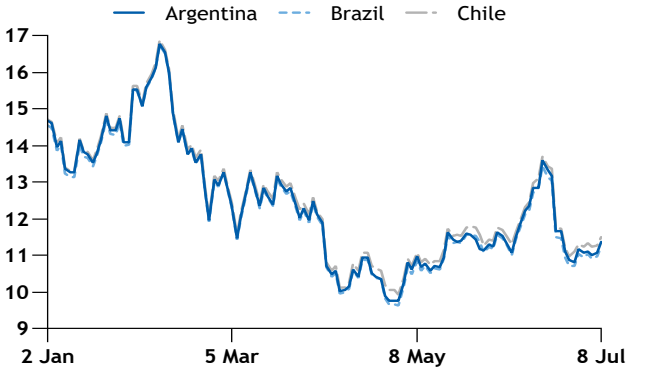
Netbacks to US Gulf coast *$/mn Btu*



US pipeline flows to Mexico *bn ft³/d*



LNG delivered to South America *$/mn Btu*



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South America LNG receipts *'000t*



Argentina's gas production falls further

Argentina's natural gas production increased on the month in May but was lower than the same month a year earlier for a third consecutive month.

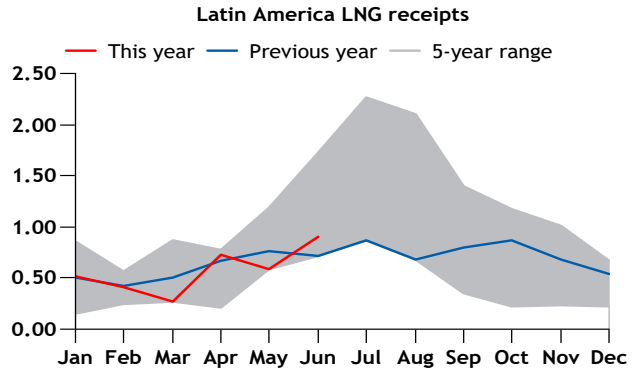
Total gas output rose by 8pc from April to 147.5mn m³/d in May, energy ministry data show. Production was the highest it has been since August last year, but it was still lower than the 150.1mn m³/d produced in May 2024. The overall trend was largely shaped by production in Neuquen, home to the Vaca Muerta shale play. Neuquen's output jumped by 12pc on the month to 102.4mn m³/d in May, but fell by 3pc on the year.

Producers may have reduced their output because of lower power demand. Argentina's total power demand fell by 1.27TWh on the year to 10.9TWh in May, according to state-owned energy wholesaler Cammesa. Demand dipped in all sectors, with residential demand accounting for the bulk of the drop, falling by 1.12TWh on the year to 4.92TWh.

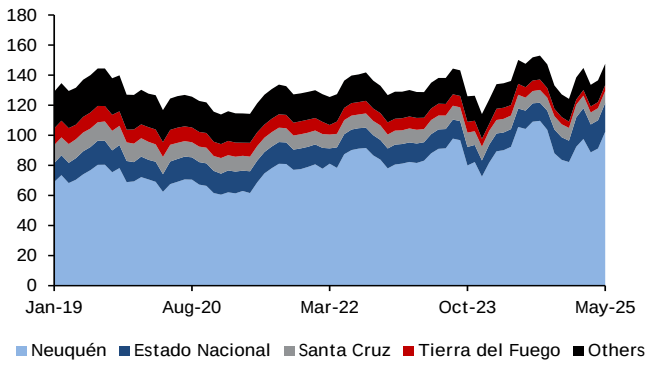
Lower power demand weighed on thermal generation, despite reduced renewable power output. Combined renewable generation, including hydropower, fell by 346GWh on the year to 4.48TWh in May, but thermal generation dropped more sharply, by 379GWh to 5.93TWh.

Argentina received about 57,400t of LNG in May, down from 93,300t in May 2024, according to analytics firm Vortexa.

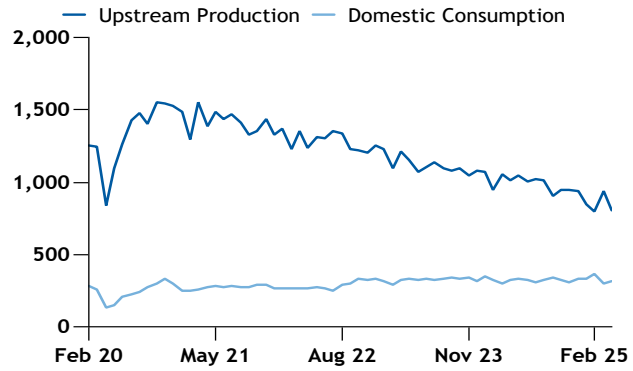
Latin America LNG seasonality chart *mn t*



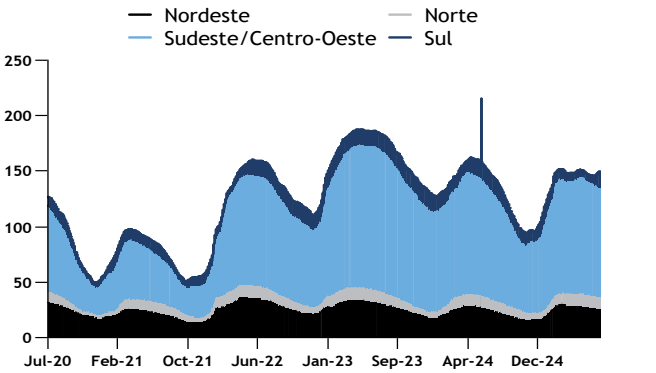
Argentina upstream production *mn m³/d*



Bolivian production and domestic demand *mn m³*



Brazil hydroelectric stocks *TWh*

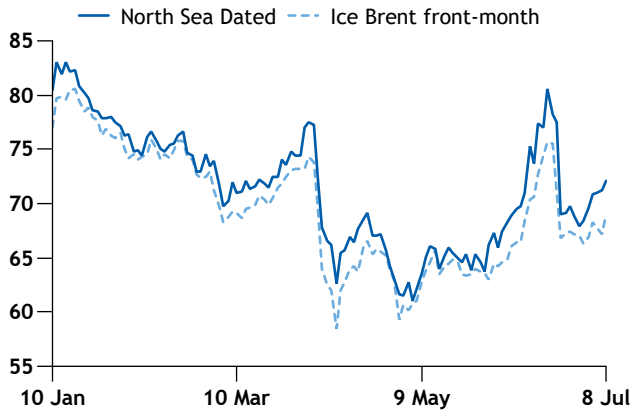


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RELATED MARKETS

Crude prices

$/bl

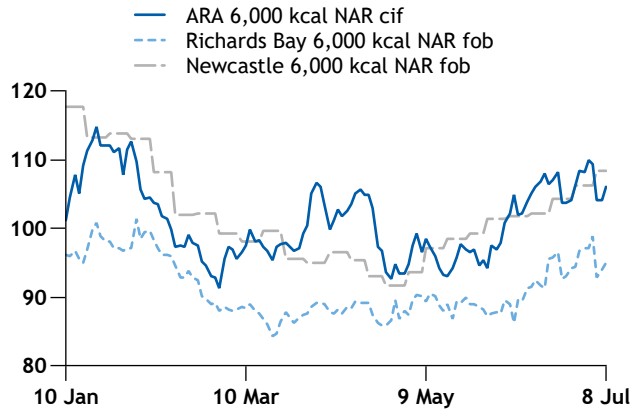


Crude prices slide

Atlantic basin crude benchmark North Sea Dated and US marker WTI eased over the past fortnight as markets weighed the longevity of a US-brokered ceasefire between Iran and Israel that began on 24 June. US president Donald Trump has suggested he could lift sanctions on Iran's oil sales, while also urging domestic producers to increase drilling. Meanwhile, Hungary and Slovakia blocked new EU measures to further limit Russian exports of crude and natural gas, but existing EU sanctions were renewed. Elsewhere, members of the Opec+ producer group are set to increase their collective output by 548,000 b/d in August. And the US has threatened further tariff action against its trading partners, to be unveiled in mid-July. North Sea Dated decreased by $6.32/bl over the past fortnight to $71.21/bl on 7 June, while WTI fell by $1.77/bl to $67.93/bl over the same period.

Coal prices

$/t

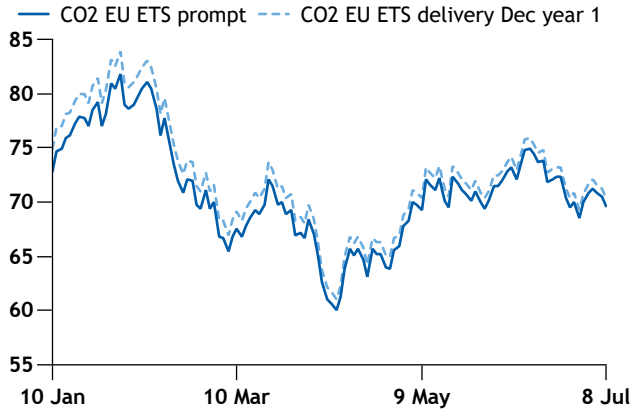


Coal prices rise

Thermal coal prices rose over the past two weeks, supported by renewed activity in paper markets. Volumes of European API 2 paper coal traded on the Ice picked up on the back of wider geopolitical instability, with energy supply concerns causing physical prices to increase. Cif Amsterdam-Rotterdam-Antwerp NAR 6,000 kcal/kg prices averaged $107.95/t from 30 June-4 July, up by $2.82/t on the week. South African coal prices rose as well, driven by gains in the European market and concerns about near-term supply shortages after operations were suspended because of a derailment. Fob Richards Bay NAR 6,000 kcal/kg prices averaged $96.50/t over 30 June-4 July, up by $2.39 on the week. Australian coal prices also saw gains, with fob Newcastle NAR 6,000 kcal/kg prices rising to $108.32/t on 4 July, up by $2.05/t from $106.27/t a week earlier, mainly because of weather-related supply disruptions in New South Wales.

EU ETS

€/t



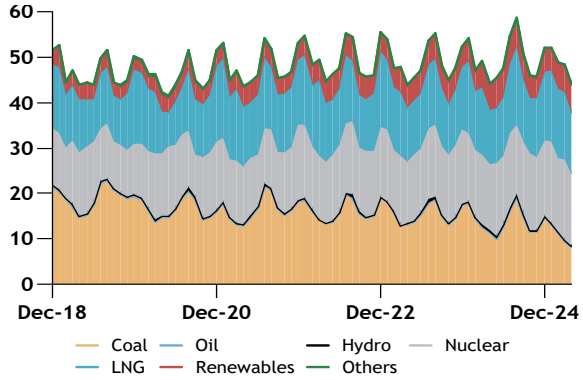
VCM demand rebounds

A large lot of 125,000 carbon credits produced in 2022 by a clean cookstoves project in Kenya traded at $11.50/t CO_2 equivalent (CO_2e), ending a dry run of several months of illiquidity. Prices for credits from Indonesia's Katingan project gained more ground as two deals for credits of 2020 and 2019 vintages were sealed at premiums to previous trades. Signs of fresh demand also emerged in the renewable energy credits market, as 100,000 credits of 2019 vintage onwards from a Gold Standard project changed hands at $0.65/t CO2e. Ghana and Switzerland issued the first internationally transferred mitigation outcome (Itmo) carbon credits generated in Africa under Article 6.2 of the Paris climate agreement. Klik, which has been tasked with compensating for parts of Switzerland's motor fuel greenhouse gas emissions, bought a total of 11,333 Itmos from project developer ACT Group.

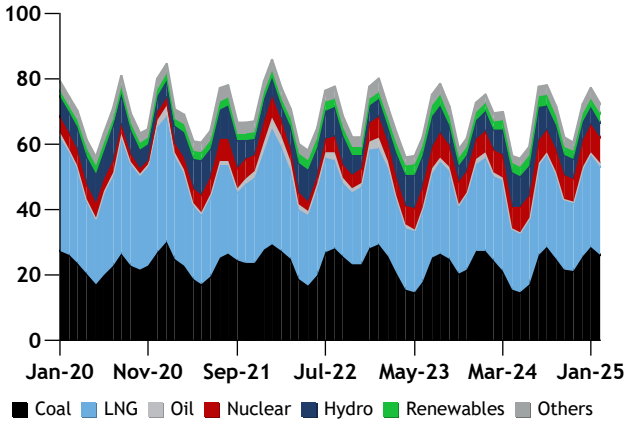
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GLOBAL GENERATION ECONOMICS

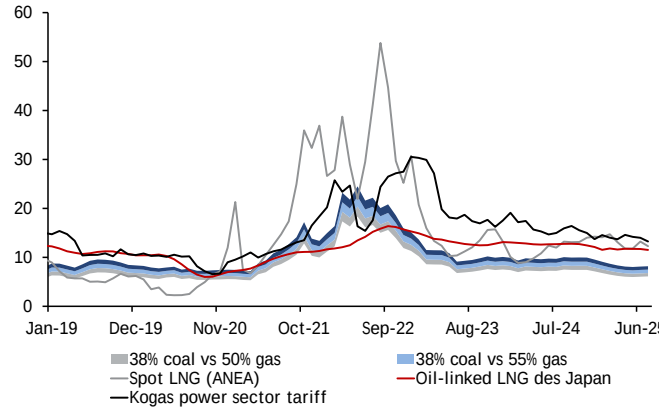
South Korea generation mix (Kepco) *GW*



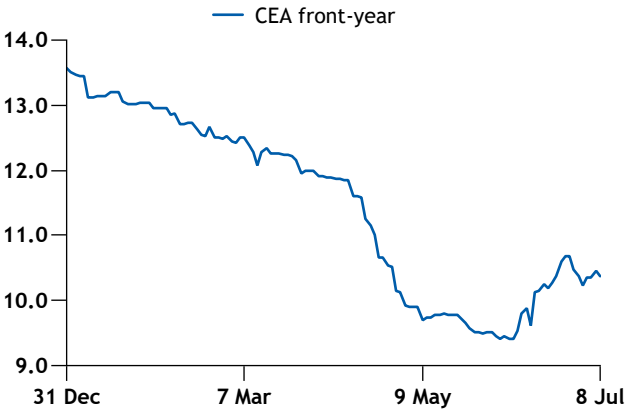
Japanese power generation mix *TWh*



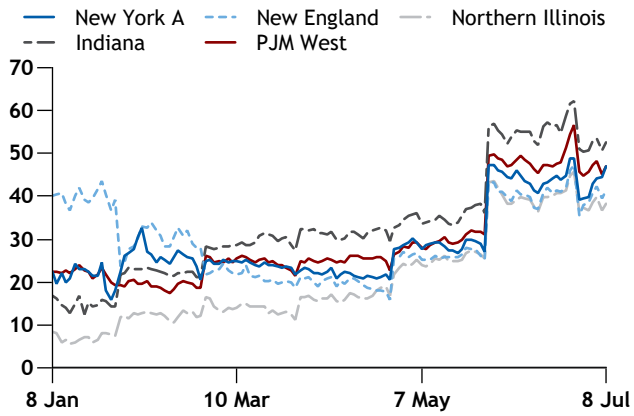
South Korea fuel switching *$/MWh*



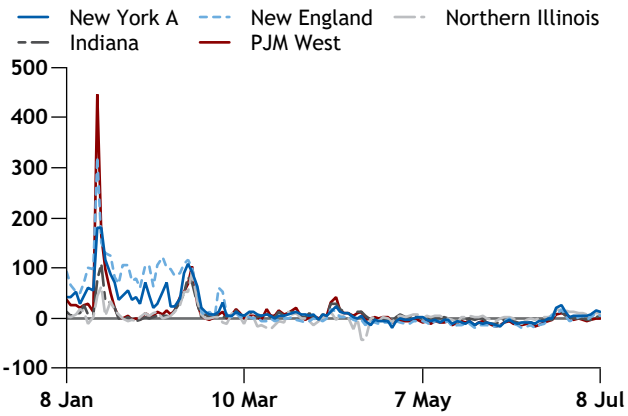
China carbon emission allowances *$/t*



US spark spreads *$/MWh*



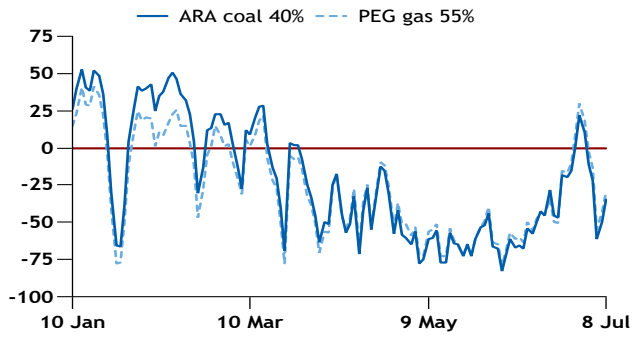
US dark spreads *$/MWh*



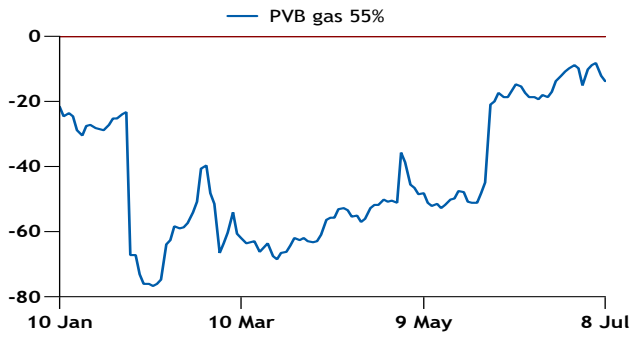
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GLOBAL GENERATION ECONOMICS

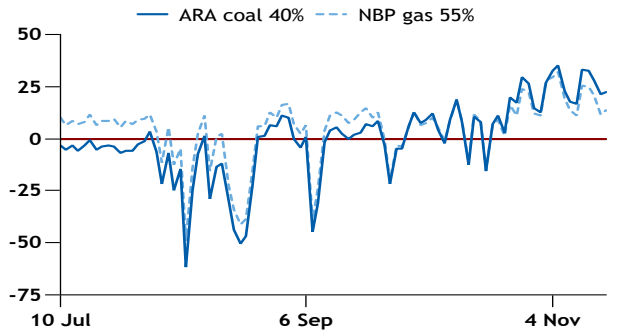
France ETS-adjusted spark spreads *€/MWh*



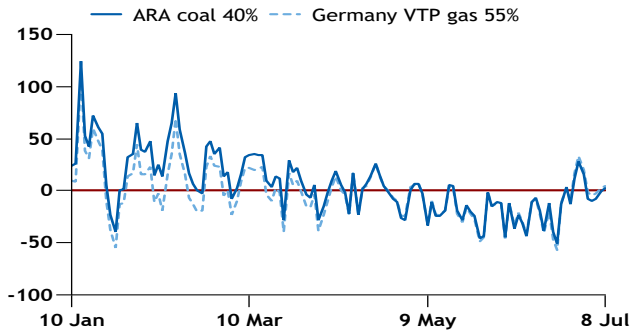
Spanish ETS-adjusted spark spreads *€/MWh*



UK sparks vs darks *£/MWh*

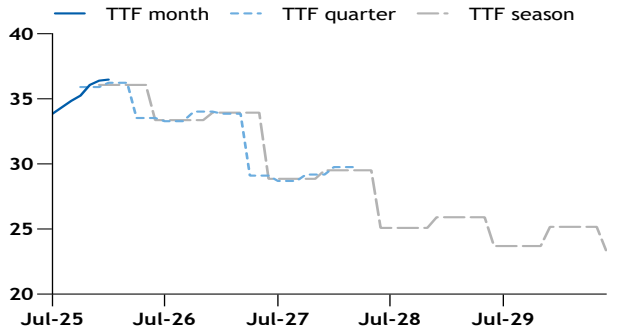


Germany sparks vs darks *€/MWh*

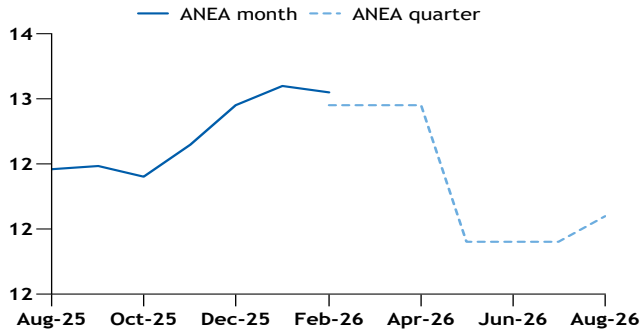


FORWARD CURVES

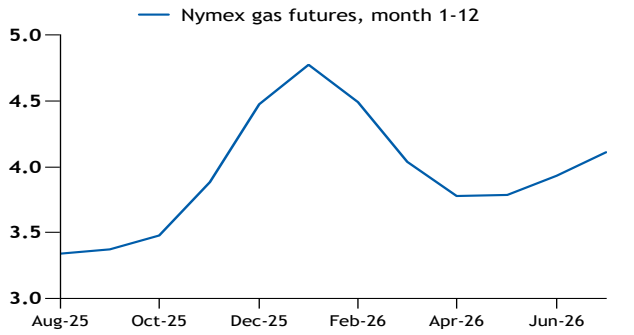
TTF *€/MWh*



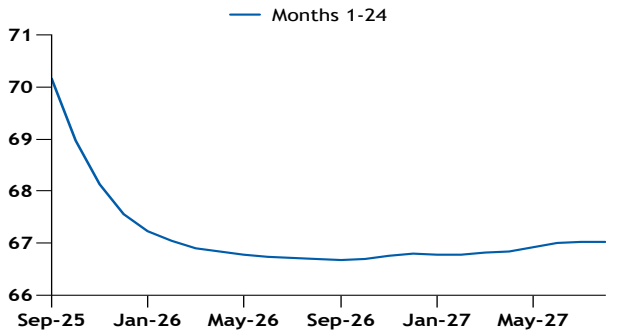
ANEA *$/mn Btu*



Henry Hub *$/mn Btu*



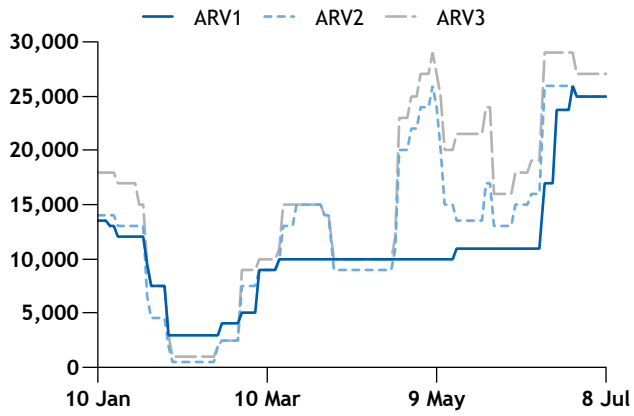
Ice Brent *$/bl*



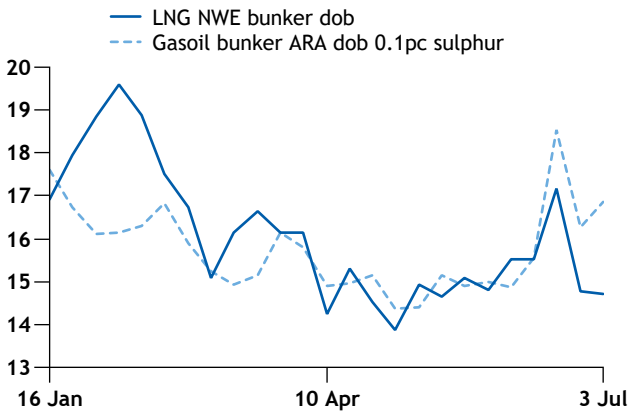
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FREIGHT AND LNG AS MARINE FUEL

Argus Round Voyage (ARV) rates *$/d*



Marine fuels competition *$/mn Btu*



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