

WORLD GAS INTELLIGENCE®

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VIEWPOINT

Geopolitical Instability Takes Energy Infrastructure Security Into New Phase

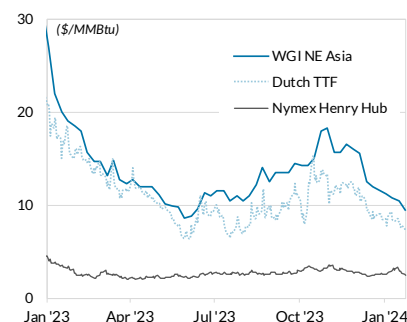
The security of natural gas and LNG infrastructure remains paramount, especially as new and enduring geopolitical conflicts across the globe turn red hot in 2024. Tight supply-demand fundamentals for the global gas market are making it so that any disruption to the status quo could be catastrophic for supply security and could drive spikes in natural gas prices as shown by last year's unplanned LNG shutdowns, such as with the labor dispute at Australian LNG export terminals.

The Russian war in Ukraine, now approaching its second year, has unleashed a twin barrage of drone attacks and alleged state-sponsored acts of sabotage on both sides of the conflict as the biggest threats to energy infrastructure. On the more traditional military front, the Russians have focused on bombing Ukraine's power grid directly, but have mostly spared its gas grid, especially the transit pipeline crucial to send Russian gas to Europe and Ukraine's vast storage infrastructure, which serves as an extra supply cushion for the EU. On the hybrid warfare front, a fire at Novatek's Ust-Luga gas-condensate export facility in Russia's Leningrad region last weekend hitting condensate and refined product exports was attributed to a drone attack launched by Ukrainian forces. Earlier in the month, drones hit an oil terminal in St. Petersburg and an oil product storage facility operated by state-run Rosneft in the Bryansk region.

Sabotage apparently related to the Ukraine war, especially the Nord Stream pipeline explosions in September 2022 and the damage to the Estonia-Finland Balticconnector line in October 2023, has led European nations to step up navy patrols assisted by Nato. More recently, German prosecutors opened an investigation earlier this month over the potential sabotage of a pipeline connecting the Brunsbüttel LNG terminal to the national grid. The nature of the threat makes it difficult to lean solely on a military response, and needs to be backed by increased cooperation with civilian authorities and private companies. "Because most of these critical undersea infrastructure is owned by private companies, operated by private companies and they have access to and control important capabilities that can help us with surveillance and also gathering information," Nato Secretary General Jens Stoltenberg said in October.

Energy maritime trade has now become a major target for state and non-state actors, as the escalation of the Israel-Gaza war through the attacks on ships by Yemen's Houthi rebels has shown. The Houthi's use of drones and ballistic missile attacks portends a new form of aggression that could be more easily and cheaply replicated, more difficult to avoid, and could be potentially more precise than previous piracy-linked attacks. "As this technology becomes more easily accessible, ensuring ship safety will be more costly and require more advanced technology," international trade expert Alex Mills wrote in a blog post for the Atlantic Council. This could have long-term repercussions on shipping leading to contract renegotiations between shipowners and operators, on the access to insurance and financing for ships, as well as the overall security of strategic chokepoints needed to transport global trade, he notes.

GLOBAL GAS PRICING



NEW PROJECTS

New Finds Could Revive Indonesia's Arun LNG Export Plans

Plans to restart LNG exports from the mothballed 12.5 million ton per year Arun liquefaction plant in Indonesia following recent large offshore gas discoveries deep in the Andaman Sea will be difficult, but not impossible to achieve, analysts say.

Arun was first converted from a six train liquefaction plant to a 3 million ton/yr regasification facility in 2015 due to a lack of feed gas. The idea to change it back to a liquefaction facility was first floated in 2022 following Harbour Energy's Timpan discovery, but gained credibility last December after Abu Dhabi's sovereign wealth fund, Mubadala, successfully drilled the Layaran exploration well.

Combined, the discoveries represent around 7.5 trillion cubic feet of gas-in-place. However, additional appraisal is required to determine how much gas is economically recoverable. Part of the answer is expected to come over the next few weeks as the West Capella rig is drilling two more wells, Halwa-1 and Gayo-1. At this stage, consultancy Wood Mackenzie estimates an initial 3.3 Tcf of recoverable resources from Layaran alone, equivalent to over 580 million barrels of oil equivalent, based on a conservative recovery factor. A recovery factor of 75% would see recoverable resources rise to 4.5 Tcf or 790 MMBoe.

This would be more than enough to revive part of Arun's liquefaction capacity. Typically, 1.1 Tcf of gas is required to feed a 1 million ton/yr LNG train for 20 years. Considering an upstream production potential of 164 MMcf/d for Timpan and 650 MMcf/d for Layaran, the gas could feed two to three trains, provided that the plant can be modified to accommodate the gas specifications from the field, Priya Thanarajan, an LNG consultant at FGE, tells Energy Intelligence.

Reviving Arun as a liquefaction plant could help save costs as the plant comes with existing infrastructure such as storage tanks, a jetty and breakwater. Looking at past conversions of regasification terminals into liquefaction facilities, such as with the Sabine Pass and Freeport facilities in the US, it took around four years to complete and helped save around 30% of the cost, analysts say.

Technical Issues Pending

Several technical questions about the facility's reconversion remain.

It is, for example, unclear how much needs to be done to renovate Arun's six LNG trains, which were built almost a half century ago.

A study to address this problem is currently underway in partnership with Perta Arun Gas, the operator of the facility and a subsidiary of state-run Pertamina Gas Negara, which will determine how many liquefaction trains will be made available, Energy Intelligence understands.

Building new liquefaction trains may be a better, but costlier, option than refurbishing existing infrastructure. Liquefaction technology has considerably changed since the legacy LNG trains were built, with current technology ensuring greater reliability, less maintenance and downtime, as well as lower emissions.

The different partners also need to be aligned on both the upstream and on the liquefaction project. Harbour and Mubadala should see eye to eye as they are already partners in all the blocks where discoveries were made. However, aligning with Pertamina Gas Negara and securing a tolling agreement to use its liquefaction trains could be more challenging. Any agreement would also have to address who handles the LNG marketing. Pertamina took control of Arun from Exxon Mobil nine years ago.

Uncertain Export Availability

Even if everything falls into place, reviving Arun would not automatically translate into large LNG exports given Jakarta's preference for domestic sales amid Indonesia's growing gas and LNG needs. Indonesian gas consumption has been increasing by 1.7% per year since 2012, while production has been declining by 2.3% annually to 6.4 billion cubic feet per day last year.

As a result, 74% of Tangguh Train 3's production is sold to Indonesian state-owned electric company PLN, while the remaining 26% is set to be exported to Japan's Kansai Electric. Also, roughly 60% of Abadi's gas will be sold on the Indonesian market to meet industrial and power generation demand.

The Arun LNG facility would also likely be operational for exports after 2030, when the market is expected to be oversupplied. However, such heightened competition should not necessarily be a major obstacle due to Indonesia's geographical advantage to markets in the Asia-Pacific. "The world will be so reliant on the US and Qatar, which will supply around half of the world's entire LNG by 2030, that diversification is something buyers are very keen for, particularly supplies from Southeast Asia as it's close to the large and growing LNG markets, so, in that respect, Indonesia and Arun are well positioned," Marc

Howson, head of Asia at consultancy Welligence Energy Analytics, tells Energy Intelligence.

Upcoming general elections in February also raise uncertainty on whether the future government will uphold recent fiscal and regulatory improvements, without which the project may be indefinitely delayed.

Marc Roussot, Singapore

EMERGING MARKETS

Senegal, Mauritania Play Hardball Over FLNG Project

The start of operations of the first phase of the BP-operated Greater Tortue Ahmeyim (GTA) floating LNG project offshore Senegal and Mauritania has been pushed to the third quarter of 2024, the energy ministers of the two countries announced last week in the Senegalese capital Dakar. This marks yet another delay in a project that is now more than two years behind its original schedule.

Mauritania's Nani Ould Chrougha and Senegal's Antoine Felix Abdoulaye Diome said in a joint statement that their views on the project were "perfectly aligned" and that they would guarantee the rights of contractors, and at the same time protect national interests. They also pledged to carry out a joint audit of the project costs, which according to a source involved in the project have spiraled beyond \$5 billion.

BP and Kosmos Energy, in charge of the upstream part of the project, did not wish to comment on the ministers' remarks. This could suggest that the relationship between the two governments and the foreign partners is deteriorating.

Presidential elections to be held this year in both countries are looming in the background, with the GTA project expected to be a contentious issue due to its importance to future economic growth. Elections in Senegal are scheduled to take place on Feb. 25 to choose a successor to the incumbent Macky Sall, who will have served his maximum two terms. Mauritania goes to the polls in late June or early July. A renegotiation of the project cannot be discounted.

The Dakar communique made no mention of the arrival earlier of this month at the GTA site of the *Gimi* floating LNG vessel, which was shipped in from Singapore by its owner, Golar LNG, and will be operated by BP under a 20-year lease. When the time comes, the ship will be linked up with a floating production, storage and offloading unit that was shipped in from China last year and will produce and process all the gas from the deepwater Tortue field and then deliver it to the *Gimi* via a 35 kilometer pipeline.

The upstream portion of the project is progressing smoothly, with Kosmos having drilled the four production wells. When start-up finally happens, the project will produce up to 2.5 million tons per year of LNG that will be marketed by BP and is expected to supply Europe. These volumes will supplement the 3.4 million tons/yr of LNG that BP is selling into Europe under a long-term offtake contract with the Coral South project in Mozambique, which started up in November 2022.

GTA, which achieved final investment decision in 2018, has been a difficult project from the outset. Problems related to the spread of Covid-19 forced BP in 2020 to declare force majeure on the delivery of the *Gimi* vessel, causing a one year-delay, while at the same time project costs increased more than 15%. Golar LNG has subsequently launched arbitration proceedings against BP for failing to live up to its commitments. BP's relationship with contractors, which include McDermott with a contract to lay the offshore pipelines of the project, have also soured.

Negotiations on a possible Phase 2 to GTA, which would have a similar capacity as Phase 1, but at a much lower cost, appear to be going nowhere. A project sanction was initially earmarked for last year, but has been pushed back indefinitely. "It's very hard to see any progress on Phase 2 until Phase 1 is up and running", a source familiar with the project says. "Right now, everyone is focused on getting operations started."

Paul Sampson, London

ENERGY TRANSITION

Growing Renewables Crowd Out Gas Use in European Power

Natural gas use for electricity generation in the EU and the UK is expected to fall further in 2024 as more wind and solar capacity are added to the energy mix. Gas-fired power output in the European region has most likely peaked in volumetric terms despite its prominence in energy plans as a steady source to support the energy transition. Gas use will still be needed to provide baseload energy during periods of extremely cold or hot temperatures, during severe drops in wind and solar photovoltaic (PV) output, when droughts diminish hydro reservoir levels or when a sizeable number of nuclear plants are offline.

The EU used some 55.4 billion cubic meters of gas in electric generation in 2023, an almost 22% drop year on year, according to the latest data from European power sector association Eurelectric. In the UK, gas use in the power sector fell from 12.8 Bcm in 2022 to 9.2 Bcm last year, the group's data shows. Total electricity generation in the EU has been falling for the last two years, amounting to 2,666 terawatt hours in 2023, a 5.7% drop on the year.

ELECTRICITY MIX IN THE EU BIG 5 MARKETS PLUS THE UK

(TWh)	2022	2023	%Chg.
Germany			
Gas	86	69	-19.8%
Coal	178	118	-33.7
Bioenergy	49	44	-10.2
Solar PV	60	63	5.0
Onshore Wind	105	125	19.0
Offshore Wind	19	24	26.3
France			
Gas	46	36	-21.7
Coal	4	2	-50.0
Bioenergy	—	—	—
Solar PV	20	22	10.0
Onshore Wind	38	52	36.8
Offshore Wind	—	—	—
Italy			
Gas	141	99	-29.8
Coal	23	10	-56.5
Bioenergy	—	—	—
Solar PV	28	31	10.7
Onshore Wind	20	25	25.0
Offshore Wind	30	41	36.7
Spain			
Gas	86	60	-30.2
Coal	8	3	-62.5
Bioenergy	—	—	—
Solar PV	36	42	16.7
Onshore Wind	63	63	0.0
Hydropower	22	31	40.9
UK			
Gas	125	89	-28.8
Coal	6	0	-100.0
Bioenergy	35	14	-60.0
Solar PV	14	12	-14.3
Onshore Wind	43	27	-37.2
Offshore Wind	37	26	-29.7
Netherlands			
Gas	48	46	-4.2
Coal	15	9	-40.0
Bioenergy	10	6	-40.0
Solar PV	17	20	17.6
Onshore Wind	14	17	21.4
Offshore Wind	8	12	50.0%

Source: Eurelectric

The erosion in the 2023 gas use numbers can be attributed to higher renewable output, as well as an increase in hydropower and nuclear power use, Eurelectric data shows. This is despite coal to gas switching, which has been favoring gas in recent months due to low natural gas hub prices and relatively high thermal coal and EU carbon permit prices. Renewables, including bioenergy, produced 1,214 TWh of electricity in 2023, compared to gas' 424 TWh,

compared to 1,116 TWh for renewables and 540 TWh for gas in 2022, Eurelectric data shows.

Wind capacity in the region keeps growing despite challenging economic and inflationary headwinds. The EU added 17 gigawatts of wind capacity in 2023 and is expected to add roughly 23 GW annually on average between 2024 and 2028, according to the International Energy Agency. The European Commission wants to add 30 GW per year of wind capacity until 2030 to hit its energy and climate targets. Lobby group WindEurope is due to provide official forecast numbers for 2024 next month.

For solar power, the picture is similar. The EU installed 55.9 GW of solar PV in 2023, a 40% increase from 2022 and doubling in just two years, lobby group SolarPower Europe tells Energy Intelligence. "As per our 'most-likely' medium scenario, solar will continue its upward trajectory in 2024, reaching 62 GW with an 11% annual increase," a spokesperson for the organization says. In 2025, SolarPower Europe forecasts a 19% annual increase, or around 73.8 GW, "followed by 84.2 GW in 2026 and 93.1 GW in 2027."

Comparatively, European gas-fired power capacity was roughly 375 GW by end-2022, and coal-fired capacity was 206 GW, according to data from energy think tank Ember.

Gas use is instead eating into the market share of coal- and lignite-fired power generation capacity in Europe, as more countries try to clean their energy production sources. In addition, wholesale market economics are favoring firing up gas power plants instead of coal or lignite, as fuel switching is being tightened by the dampening effect that renewable output with relatively low marginal running costs is having on wholesale electricity prices. These relatively low electricity prices could see clean spark spreads — that is, the cost of generating power from gas including carbon costs — and clean dark spreads — the cost of generation power from coal including carbon costs — edging into negative territory in Germany over the coming months, an energy trader says, favoring gas over coal power. Market indicators are pointing towards natural gas rather than thermal coal power generation, with both Dutch and German natural gas futures remaining low with a low short-run marginal cost following the curve, according to Lukas Sigg, founder and CEO of Nordic Energy Consulting.

Jason Eden, London

HORIZON

US Upstream Prepares for Coming LNG Export Wave

The US upstream sector continues to ramp up for the next wave of US LNG export capacity with a series of recent moves designed to connect North American supplies to global gas markets.

While that strategy has typically centered around deals to supply feed gas to existing and planned LNG terminals, it increasingly involves multibillion-dollar mergers of companies with well-positioned upstream assets.

“By combining our companies, we are LNG-ready,” Chesapeake Energy CEO Nick Dell’Osso said earlier this month after his company agreed to merge with Southwestern Energy in an \$11.5 billion all-stock deal. “We expect to ultimately link up to 20% of our production to international pricing to reprice our molecule to the global markets, which will enhance revenues and reduce pricing volatility.”

Dell’Osso said the deal, which will create the largest US gas producer at 7.4 billion cubic feet per day, “redefines the natural gas producer, forming the first US-based independent that can truly compete on an international scale. The world is short energy, and demand for our products is growing, both in the US and overseas. We will be positioned to deliver more natural gas at a lower cost.”

The merger follows Tokyo Gas’ announced plan to acquire Haynesville Shale gas producer Rockcliff Energy for \$2.7 billion — another deal aimed at shoring up access to the coming wave of US Gulf Coast LNG terminals and expansions. Analysts at Tudor Pickering Holt predict more than 14 Bcf/d of LNG capacity will make it to market over the next three years.

“Low and volatile gas prices have been a significant hinderance to gas M&A, with just about \$6 billion in gas-focused deals

transacted in 2023 compared to a massive \$186 billion of oil-weighted M&A,” said Andrew Dittmar, senior vice president of Enverus Intelligence Research. But “an LNG-influenced rise in gas prices nears, there should be more enthusiasm from buyers to offer higher prices for assets and companies and drive more gas-weighted M&A.”

And some analysts think this is just the beginning. “I do think this consolidation will continue,” Atlas Consulting CEO Dallas Salazar tells Energy Intelligence, explaining that the current bear market provides incentive for well-financed buyers to snag assets whose value is certain to benefit from the LNG boom.

The strategy mirrors, at least contractually, the integrated model championed by US LNG pioneer Charif Souki, in which LNG exporters owned the molecules from wellhead to liquefaction dock.

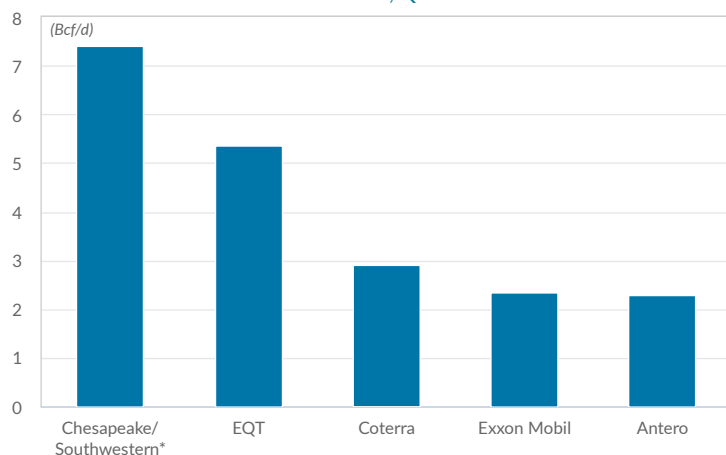
Tolling Deals

EQT, which will slide from the largest US gas producer to runner-up, is taking a different approach — although it is not ruling out potential mergers or acquisitions. The Appalachia-focused company is engaging in a series of tolling deals with US LNG projects. The most recent, on Jan. 11, was a heads of agreement for liquefaction services from Texas LNG’s proposed 4 million ton per year facility in Brownsville, Texas. The deal would have Texas LNG produce 500,000 tons/yr under a 15-year tolling agreement.

Last summer, EQT signed a preliminary supply deal with Lake Charles LNG for 1 million tons/yr for a 15-year term. Then, in September, EQT signed another preliminary 1 million ton/yr tolling agreement, also for 15 years, with Commonwealth LNG. “Our tolling capacity gives us direct connectivity to end users of natural gas globally, allowing for end-market structuring flexibility and superior downside protection,” according to Toby Rice, EQT’s president and CEO, who has been outspoken about the need for US producers to bolster demand via the global LNG market.

But Rice also has a warning: Without new takeaway capacity soon, pipelines in the Northeast and Mid-Atlantic regions will max out and gas that otherwise could provide feed gas to LNG terminals will be trapped. “The fact that we built fewer pipelines last year than in the past 30 years is just remarkable,” he told delegates at Hart Energy’s recent DUG Appalachia conference, noting that since 2010 gas demand has risen 56%, while pipeline capacity has grown only 25%. Given the impending surge of new demand from LNG and other sources, “that is not sustainable,” Rice said.

TOP US GAS PRODUCERS BY VOLUME, Q3’23



*Pro forma estimate. Source: Corporate filings

Traders Step Up

Meanwhile, large global traders have advanced in their traditional role of connecting buyers and sellers, bringing that expertise to North American markets. Leading commodities trader Trafigura, in another January deal, expanded its North American LNG portfolio by signing a seven-year offtake contract with Canada's largest gas producer Tourmaline Oil Corp., which will start in early 2027.

The contract, the first between the two companies, will see Trafigura buy 500,000 tons of LNG from Tourmaline that will be priced against the Japan Korea Marker, the de facto pricing benchmark used for spot LNG shipments to the Far East.

The deal follows a deal that rival trader Gunvor did with Delfin Midstream back in November in which Delfin agreed to supply between 500,000 million tons/yr and 1 million tons/yr to Gunvor on a f.o.b. basis for a term of 15 years.

Cheniere as Facilitator

On the downstream front, meanwhile, leading US LNG exporter Cheniere is using its now hefty revenue to facilitate connections between the US upstream and world gas markets.

Cheniere's deal with Austria's OMV earlier this month price-linked US LNG to the Dutch TTF index, Europe's benchmark gas hub, rather than Henry Hub. However, the deal is considered to be an offset to an earlier integrated production marketing (IPM) gas supply agreement with Canadian producer ARC Resources, which will receive a TTF-linked price for the 140,000 million Btu per day (3.69 million cubic meters per day) of gas it supplies to Sabine Pass.

Cheniere has long emphasized the importance of IPM agreements with gas suppliers as the company builds its portfolio of liquefaction projects.

*Mark Davidson, Washington, Michael Sultan, Washington,
Caroline Evans, Houston, Paul Sampson, London*

MARKET INSIGHT

Cold Blast Drives Atlantic Storage Withdrawals

Extremely cold weather on both sides of the Atlantic is expected to lead to the highest storage withdrawal volumes for the season for the US and the EU.

After reaching two-month highs, US gas futures fell precipitously last week in a sign that traders are looking past the severe cold snap that may lead to the biggest storage draw of the season.

The February Nymex Henry Hub contract sank 17.8¢ on Jan. 19 to \$2.519 per million Btu, capping off a 79.4¢ plunge over the week's four trading days. The largest Friday-to-Friday decline in the prompt month in more than a year was also notable given that it coincided with the coldest temperatures of the winter.

In the week ending Jan. 17, that Arctic blast pushed domestic consumption 20.9% higher from the week prior to 123.4 billion cubic feet per day, with residential and commercial consumption rising 36.9% to 58.2 Bcf/d and power-sector demand up 10.8% to 38.1 Bcf/d.

At the same time, well freeze-offs lowered dry gas production by 7.9% to 95.6 Bcf/d. But analysts estimate the decline in production at its peak was about half of the 20 Bcf/d drop anticipated as the Arctic air approached toward the end of the second week of January.

Adding to the bearish sentiment was a weekly gas storage draw that came in 10 Bcf below consensus estimates. The US Energy Information Administration (EIA) reported a 154 Bcf pull for the week ended Jan. 12 — compared to analysts' consensus forecast of 164 Bcf — lowering working gas inventories to 3,182 Bcf. That compares with a year-ago pull of 68 Bcf and the five-year average withdrawal of 126 Bcf. The surplus to the five-year average

fell to 320 Bcf, or 11.2%, while the surplus to last year declined to 350 Bcf, or 12.4%.

However, data for the week ending Jan. 19, which will show the impact of last week's extreme weather, is expected to show a 288 Bcf withdrawal — well above the five-year average pull of 148 Bcf and the year-ago withdrawal of 86 Bcf. "The key thing for this market is going to be whether or not this polar vortex is done, or we get a second wave of extreme cold," Price Futures Group analyst Phil Flynn said. "A second wave of a polar vortex ... could extend winter into March. If that's the case, natural gas could still spike."

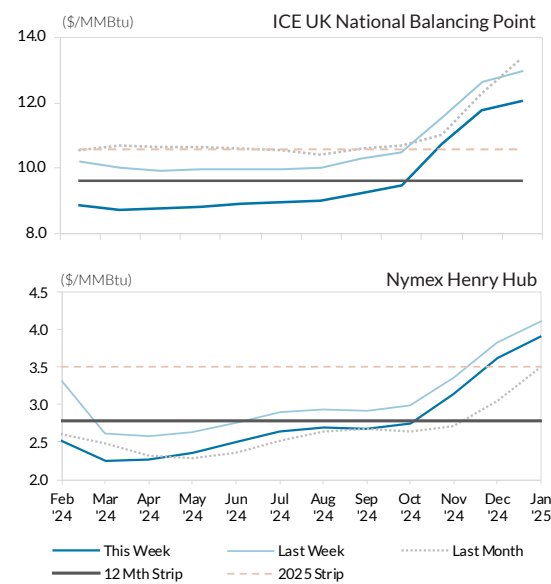
Meanwhile, EU gas storage withdrawals hit their highest levels so far this winter during January as a cold snap gripped the continent. Storage draws are expected to slow over the remainder of the month as mild and windy weather has returned, which is expected to ease gas demand.

EU gas storage withdrawals averaged approximately 8,658 gigawatt hours per day (around 886 million cubic meters per day) between Jan. 8-14, marking the largest draws on the bloc's gas inventories so far this winter, according to preliminary data from Gas Infrastructure Europe. In comparison, withdrawals averaged an estimated 6,725 GWh/d over the first 21 days of January and around 4,681 GWh/d over the first 21 days of December 2023.

EU storage sites were approximately 74% full on Jan. 21, down from around 78% on the same date last year. However, the bloc's storage levels are still markedly higher than the five-year average of approximately 63%, and analysts have suggested storage could exit winter around 50%-55% full.

Everett Wheeler, Washington, Eric Thorp, London

NATURAL GAS FUTURES



SPOT LNG

LNG Prices Slump to Lowest Levels in Eight Months

Spot LNG prices in Northeast Asia dropped by 95¢ to \$9.50 per million Btu, according to Energy Intelligence assessments for deliveries four to eight weeks ahead. Spot LNG prices in Southwest Europe fell by 85¢ week on week to \$8.00/MMBtu.

Ample supplies, high gas and LNG inventories and weak demand have all contributed to drag spot LNG prices in both Europe and Asia to their lowest levels in around eight months.

Geopolitical flareups around the world have not had any impact on global LNG prices. A drone attack on Russian independent Novatek's Ust-Luga gas-condensate export terminal over the weekend has barely registered in the gas markets, while lingering disruptions in the Red Sea, which have prompted LNG tankers to divert their transit away from crossing the Suez Canal route, have yet to affect global supplies. Indian industry sources have said that the impact of the diversions has been limited due to low reliance on LNG cargoes travelling through the Suez.

Demand in Northeast Asia has remained muted due to healthy inventories, while a cold snap hitting China late last week did not prompt demand for spot LNG cargoes. In Japan, LNG stocks rose 2.8% on the week to reach 2.58 million tons due to a higher number of ships, according to Ministry of Economy, Trade and Industry data from Jan. 17.

South and southeast Asian markets did see the emergence of demand for spot cargoes attracted by the recent dip in LNG prices, mostly from India. Indian Oil Corp. issued a tender for a cargo to Dhamra for Feb. 10–24 and a cargo for Dahej for Mar. 24. Gail issued two separate swap tenders. The first for two cargoes per month for 2026 in exchange for two cargoes per month from the Sabine Pass plant in the US Gulf in 2026. Another swap tender was issued for one cargo from

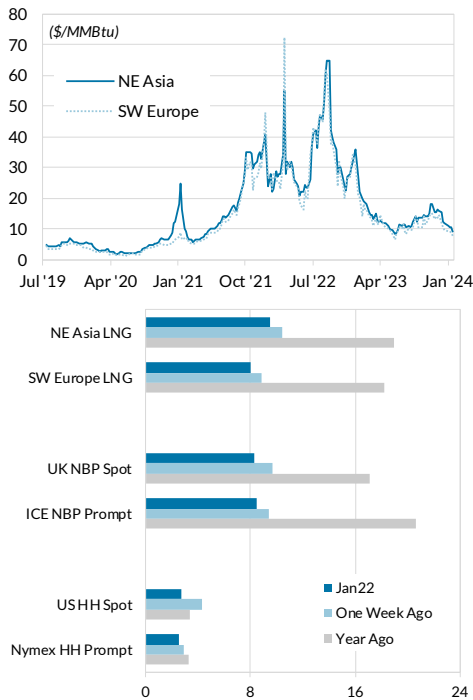
the US on an f.o.b. basis loading on Mar. 26, while seeking one cargo for Mar. 16–26 on a delivered ex ship (d.e.s.) basis to Dabhol. Petronet issued a buy tender for two cargoes with delivery over Mar. 15–20 and May. 1–7. Gujarat State Petroleum Corp. also issued a tender to purchase a cargo for the second half of February to Dahej or Dhamra.

INDICATIVE NATURAL GAS PRICES

(\$/MMBtu)	Jan 22	Week Ago	Year Ago
NE Asia LNG	9.50	10.45	19.00
SW Europe LNG	8.00	8.85	18.20
UK NBP Spot	8.33	9.70	17.08
ICE NBP Prompt	8.50	9.43	20.63
USHH Spot	2.68	4.34	3.35
Nymex HH Prompt	2.52	2.90	3.26

Source: WGI assessments of spot prices for LNG in NE Asia and SW Europe and for day-ahead gas in the UK. NGW spot assessment for US. All prices are for Mon, Jan 22. Note: Dates may vary due to public holidays and availability.

INDICATIVE LNG PRICES



Thailand's PTT issued a buy tender for three cargoes to be delivered over Feb. 1–2, Mar. 1–2 and Mar. 17–18. Kuwait Petroleum Corp. issued a tender for procuring cargoes in February and March.

On the sell side, Oman LNG offered two cargoes on a d.e.s. basis over Feb. 21–13 and Feb. 23–27 to northeast Asia. Japan's Itochu sold a cargo on behalf of Kuwait's Kufpec for loading over Feb. 24–18 at Australia's 8.5 million ton per year Wheatstone LNG.

Southwest Europe reported a similar situation as in Asia, where subdued continental demand and healthy underground gas storage facilities dragged spot LNG prices lower following a bearish Dutch TTF gas trading hub.

In a rather unusual move, China's state-owned PetroChina has unloaded a Yamal LNG cargo at Spain's Huelva terminal on Jan. 22, which it received via a ship-to-ship transfer at Belgium's Zeebrugge terminal on Jan. 13. It was not immediately clear whether the cargo is going to be reloaded once again from Huelva to another vessel or whether it will be regasified and fed into the Spanish grid.

The 154,500 cubic meter *Karadeniz LNG Powership Anatolia*, partially laden with a reload from Spain's Huelva terminal, has arrived at the Congo floating LNG plant on Jan. 20, but it is understood that the vessel will not lift the first cargo from the project.

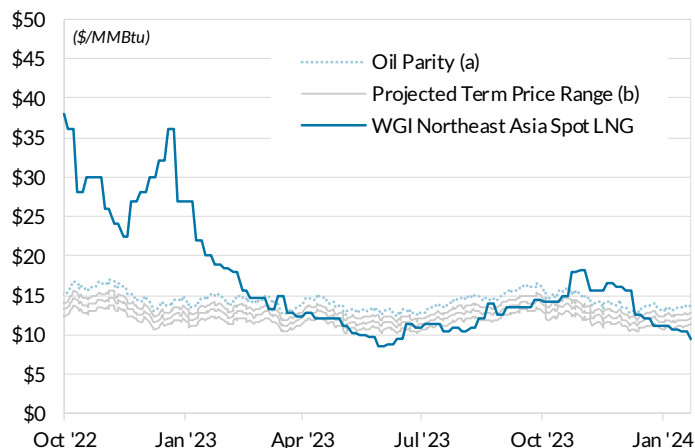
Yousra Samaha, Dubai, Daniel Stemler, Madrid

WORLD GAS INTELLIGENCE LNG ANALYTICS

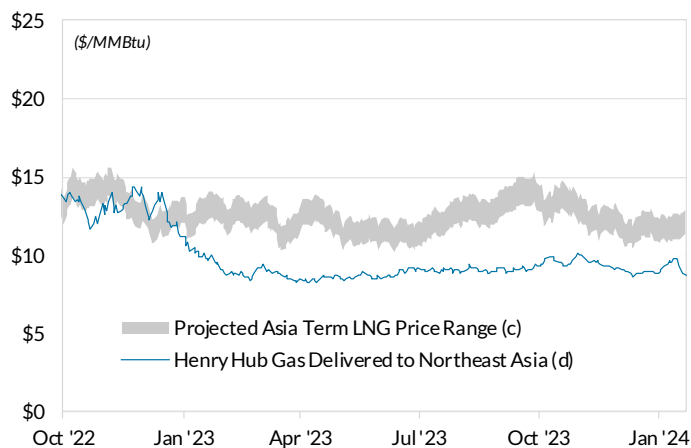


The following graphs provide weekly comparative insights into key LNG market relationships over the previous 12 months, with particular emphasis on the price of competing supplies in Asia and key inter-market price spreads.

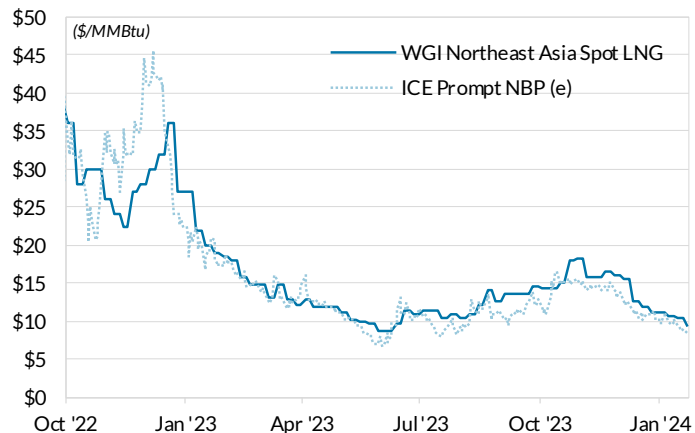
NORTHEAST ASIA SPOT LNG VERSUS ASIA TERM LNG



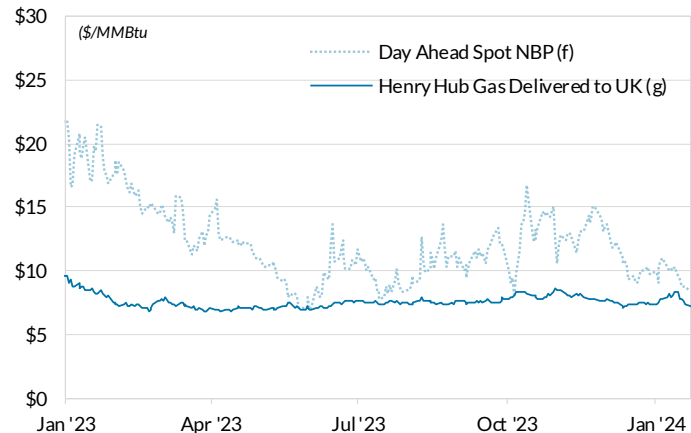
HENRY HUB NE ASIA VERSUS ASIA TERM LNG



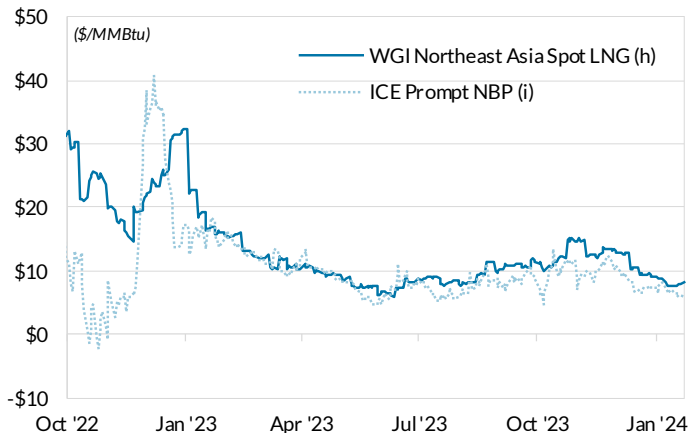
NBP VERSUS NORTHEAST ASIA SPOT LNG



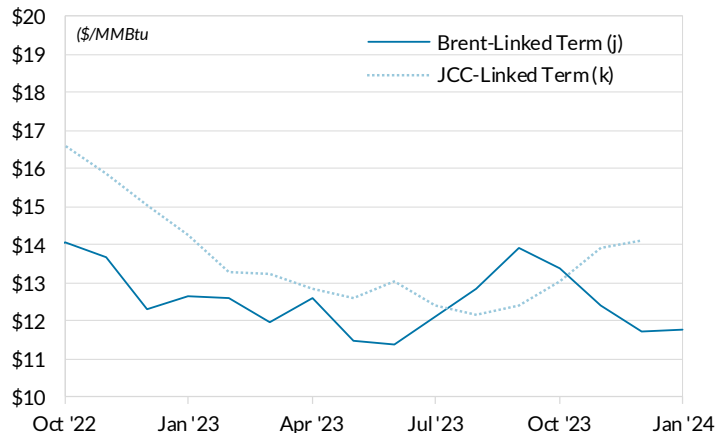
HENRY HUB GAS DELIVERED TO UK VERSUS NBP



REGIONAL PRICE DIFFERENTIALS TO NYMEX HENRY HUB PROMPT



TERM JCC VERSUS TERM BRENT



(a) Oil parity - 17.24% of Brent-Linked Asian Term. (b) Estimated low, middle, and high cases for contract terms: 13.5% of Brent+\$0.50, 14.5% of Brent+\$0.50, and 14.85% of Brent+\$1.00, respectively. (c) Brent-Linked Asian Term LNG, high and low cases. (d) Per Cheniere formula: 115% Henry Hub plus \$3.50 for liquefaction and \$2.50 for shipping. (e) ICE prompt NBP converted from pence/therm to US\$/MMBtu. (f) Thomson Reuters Day Ahead NBP converted from pence/therm to US\$/MMBtu. (g) Per Cheniere formula: 115% of Henry Hub plus \$3.50 for liquefaction and \$1.00 for shipping. (h) Northeast Asia Spot vs Nymex Henry Hub Prompt. (i) Day Ahead UK NBP vs Nymex Henry Hub Prompt. (j) Term prices based on current month average against mid-case formula for delivery 3 months later; (k) JCC is Monthly Japan Crude Cocktail Price reported by Japan's Ministry of Finance.

WORLD GAS INTELLIGENCE LNG ANALYTICS

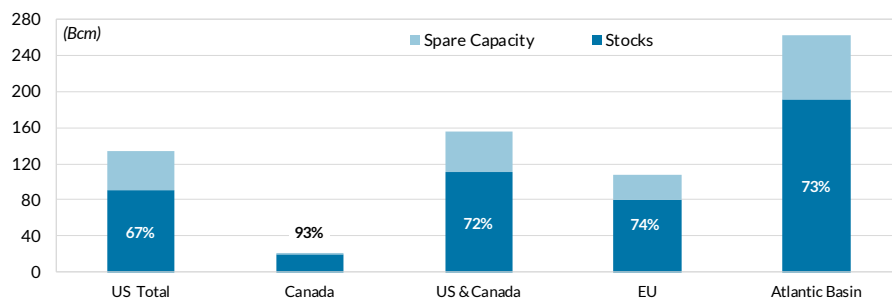


VOLUMES OF GAS IN ATLANTIC BASIN STORAGE

		(in BCF)				(in Bcm)			
		Most Recent [†]	Prior Week	Year-Ago	3-Yr Avg.	Most Recent [†]	Prior Week	Year-Ago	3-Yr Avg.
European Union	% Full								
Austria	84.3	275.9	288.4	269.3	209.1	7.8	8.2	7.6	5.9
Belgium	63.0	18.6	21.3	20.1	17.2	0.5	0.6	0.6	0.5
Bulgaria	74.0	14.6	15.3	16.0	12.4	0.4	0.4	0.5	0.4
Croatia	59.7	9.5	10.5	14.3	10.2	0.3	0.3	0.4	0.3
Czech Rep.	77.8	117.0	123.5	120.6	96.7	3.3	3.5	3.4	2.7
Denmark	79.3	26.9	29.0	29.5	25.3	0.8	0.8	0.8	0.7
France	65.1	292.9	322.8	325.3	265.2	8.3	9.1	9.2	7.5
Germany	77.8	664.0	710.5	710.9	572.9	18.8	20.1	20.1	16.2
Hungary	79.5	186.7	193.6	141.4	138.2	5.3	5.5	4.0	3.9
Italy	70.7	466.3	491.1	492.6	437.2	13.2	13.9	14.0	12.4
Netherlands	69.7	333.0	355.5	337.2	271.5	9.4	10.1	9.5	7.7
Poland	84.4	106.1	111.3	113.3	101.8	3.0	3.2	3.2	2.9
Portugal	97.0	11.6	11.5	13.1	11.5	0.3	0.3	0.4	0.3
Slovakia	74.4	91.8	94.8	92.9	77.0	2.6	2.7	2.6	2.2
Spain	84.6	96.6	99.2	109.7	92.5	2.7	2.8	3.1	2.6
UK	53.05	17.5	23.8	26.0	22.2	0.5	0.7	0.7	0.6
EU Total*	74.4	2,842	3,017	2,920	2,446	80.47	85.43	82.70	69.26
US & Canada									
East	66.0	715	757	662	682	20.25	21.44	18.75	19.31
Midwest	71.1	873	924	785	809	24.72	26.16	22.23	22.92
South Central	71.6	1,128	1,160	1,069	1,072	31.94	32.85	30.27	30.36
Mountain	44.1	208	220	147	169	5.89	6.23	4.16	4.78
Pacific	69.7	257	275	157	205	7.28	7.79	4.45	5.80
US Total	67.3	3,182	3,336	2,820	2,937	90.08	94.47	79.85	83.17
Canada	92.7	714	753	528	629	20.23	21.31	14.95	17.81
US & Canada	71.9	3,896	4,089	3,348	3,566	110.31	115.78	94.80	100.98
EU	74.4	2,842	3,017	2,920	2,446	80.47	85.43	82.70	69.26
Atlantic Basin	73.0	6,738	7,106	6,268	6,012	190.78	201.21	177.50	170.24

Sources: US-EIA, Canada-RBN Energy, European Hubs-Gas Storage Europe (GSE). *Not comprehensive. Includes only market or regions listed individually in this table. GSE data provided in terawatt-hours converted at 1 cubic meter of gas = 10.54 kilowatt hours. †US data valid as of Jan 12, Canada data valid as of Jan 18, EU data valid as of Jan 21

CAPACITY UTILIZATION IN ATLANTIC NATURAL GAS STORAGE



GAS, POWER PRICES & SPARK SPREADS FOR GENERATORS AT MAJOR HUBS

Europe				US			
Gas Price (\$/MMBtu)	Jan 22	Week Ago	Last Year	Gas Price (\$/MMBtu)	Jan 22	Week Ago	Last Year
NBP(UK)	8.33	9.70	17.08	Transco Z6 NNY	9.93	11.23	2.71
Zeebrugge	8.57	9.80	17.82	Houston SC	2.36	8.28	2.55
Dutch TTF	8.61	9.73	18.30	Socal Border (Calif.)	3.65	11.95	12.72
German THE	8.81	9.83	17.73	Stanfield (Wash.)	3.82	15.67	11.86
Power Price (\$/MWh)				Power Price (\$/MWh)			
UK Power Grid	75.28	107.16	162.21	PJM West	75.57	108.43	34.57
Tennet T	63.90	106.46	147.24	Ercot	57.18	24.29	25.85
Powernext	62.02	112.84	173.81	Palo Verde	50.71	118.17	93.57
Amprion	56.90	110.75	127.52	Mid-Columbia	124.86	707.67	140.00
Spark Spreads (\$/MWh)				Spark Spreads (\$/MWh)			
NBP/UK Power Grid	+16.97	+39.25	+74.81	TZ6 NNY/PJM W	+6.04	+29.82	+19.26
Zee/TenneT	+3.94	+37.89	+79.64	Houston SC/Ercot	+40.67	-33.69	+13.46
Zee/Powernext	+2.06	+44.27	+84.83	Socal/Palo Verde	+25.14	+34.55	+1.16
Dutch TTF / TenneT	+3.66	+38.34	+67.79	Stanfield/Mid-Col.	+98.11	+597.97	+40.31
German THE/Amprion	-4.79	+41.95	+70.33				

US prices are the weighted average of assessments by Natural Gas Week for five trading days, spanning Jan 15-Jan 22. European gas prices are WGI assessments on Jan 23 for day-ahead delivery Jan 24. European power prices are from exchanges on Jan 22 for day-ahead power Jan 23. Gas quotes on top, power below. Heat efficiency of 7,000, or 48%, is used to calculate spark spreads, i.e. 7 MMBtu of gas generates 1 MWh of electricity. Note: Dates may vary due to public holidays and availability.

SPOT LNG EXPORTER NETBACKS AT KEY MARKETS

(\$/MMBtu)	Jan 22	Week Ago	Two Weeks Ago	Year Ago
NE Asia				
Algeria	8.53	8.27	7.68	17.95
Australia	9.66	9.39	9.39	19.21
Indonesia	9.79	9.52	9.61	19.36
Malaysia	9.73	9.47	9.55	19.30
Nigeria	8.51	8.24	7.54	17.91
Norway	5.67	5.41	2.98	14.73
Peru	7.63	7.38	6.06	16.92
Qatar	9.26	8.99	8.73	18.75
Russia	10.02	9.75	9.98	19.62
Trinidad	7.90	7.64	6.63	17.23
US Gulf	7.17	6.91	5.44	16.42

India				
Algeria	7.68	7.42	7.31	17.20
Australia	8.06	7.79	7.80	17.61
Indonesia	8.04	7.78	7.77	17.59
Malaysia	8.04	7.77	7.80	17.59
Nigeria	7.41	7.15	6.77	16.88
Norway	7.27	7.01	6.63	16.73
Peru	7.01	6.75	6.06	16.41
Qatar	8.35	8.09	8.29	17.95
Russia	7.78	7.52	7.34	17.29
Trinidad	7.14	6.88	6.42	16.59
US Gulf	6.92	6.66	6.06	16.34

SW Europe				
Algeria	7.22	8.22	8.84	17.74
Australia	5.94	6.92	6.82	16.28
Indonesia	5.95	6.94	6.85	16.30
Malaysia	5.99	6.97	6.94	16.35
Nigeria	6.80	7.79	8.16	17.26
Norway	6.65	7.64	7.88	17.08
Peru	5.53	6.52	6.15	15.83
Qatar	6.42	7.41	7.62	16.84
Russia	5.64	6.63	6.33	15.94
Trinidad	6.86	7.85	8.22	17.32
US Gulf	6.06	7.05	6.90	16.41

UK				
Algeria	7.95	8.68	9.12	20.51
Australia	6.61	7.34	7.03	18.98
Indonesia	6.63	7.36	7.06	18.99
Malaysia	6.66	7.39	7.15	19.04
Nigeria	7.56	8.29	8.50	20.06
Norway	7.82	8.56	8.90	20.36
Peru	6.28	7.00	6.47	18.60
Qatar	7.12	7.85	7.87	19.56
Russia	6.31	7.04	6.53	18.63
Trinidad	7.65	8.38	8.61	20.15
US Gulf	6.90	7.63	7.37	19.29

Zeebrugge				
Algeria	11.83	12.59	12.52	19.34
Australia	10.46	11.21	10.40	17.82
Indonesia	10.48	11.23	10.43	17.84
Malaysia	10.52	11.27	10.53	17.89
Nigeria	11.41	12.16	11.86	18.87
Norway	11.70	12.46	12.31	19.19
Peru	10.11	10.86	9.83	17.44
Qatar	10.98	11.73	11.24	18.40
Russia	10.15	10.89	9.89	17.47
Trinidad	11.52	12.28	12.00	18.98
US Gulf	10.75	11.50	10.74	18.13

US East Coast				
Algeria	1.37	16.80	1.88	2.44
Nigeria	1.10	16.50	1.47	2.16
Norway	0.99	16.36	1.23	2.03
Peru	0.72	16.09	0.91	1.76
Qatar	0.54	15.87	0.61	1.56
Trinidad	1.54	17.00	2.17	2.62

Click [here](#) for WGI LNG Netback methodology.