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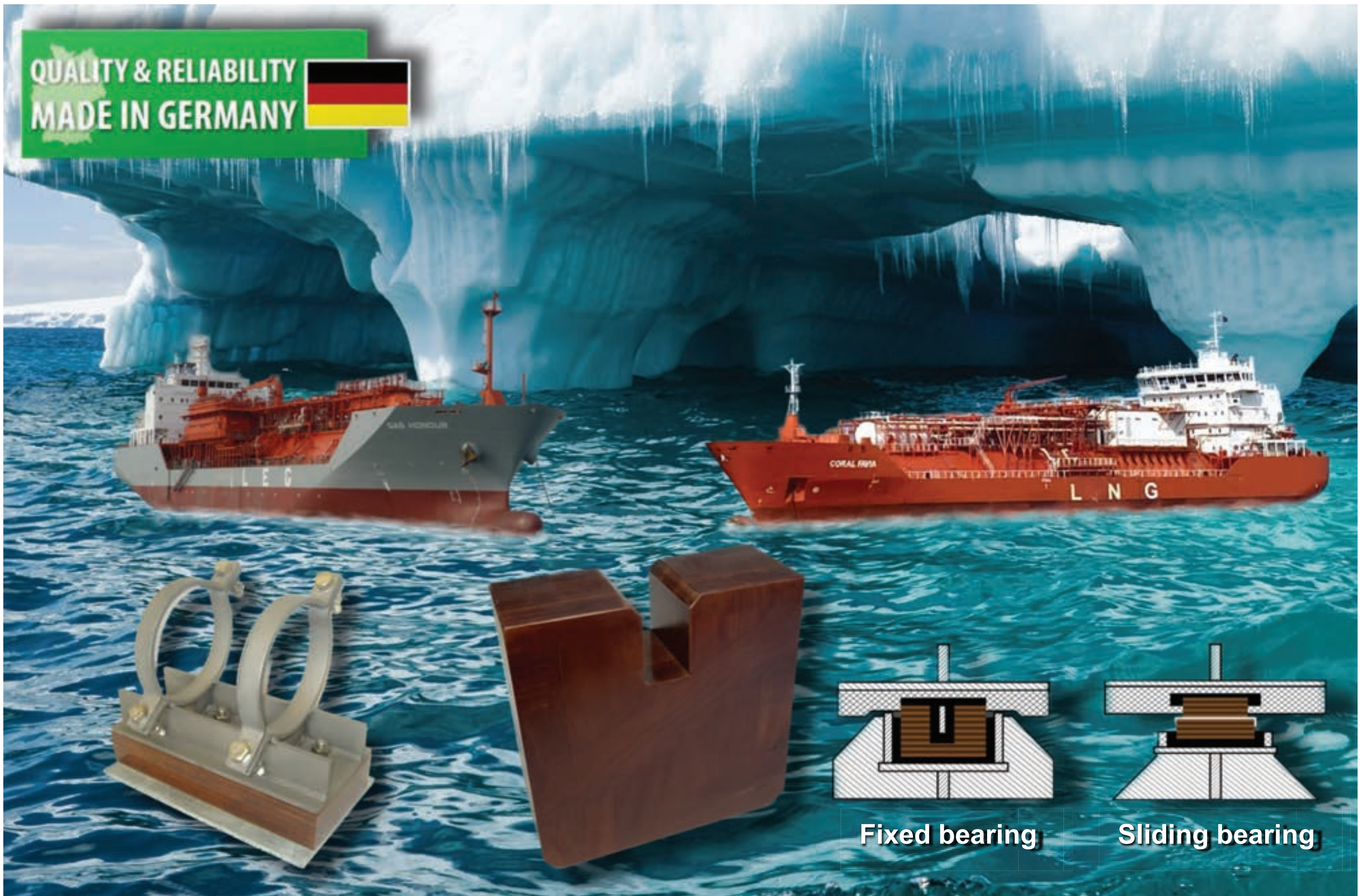

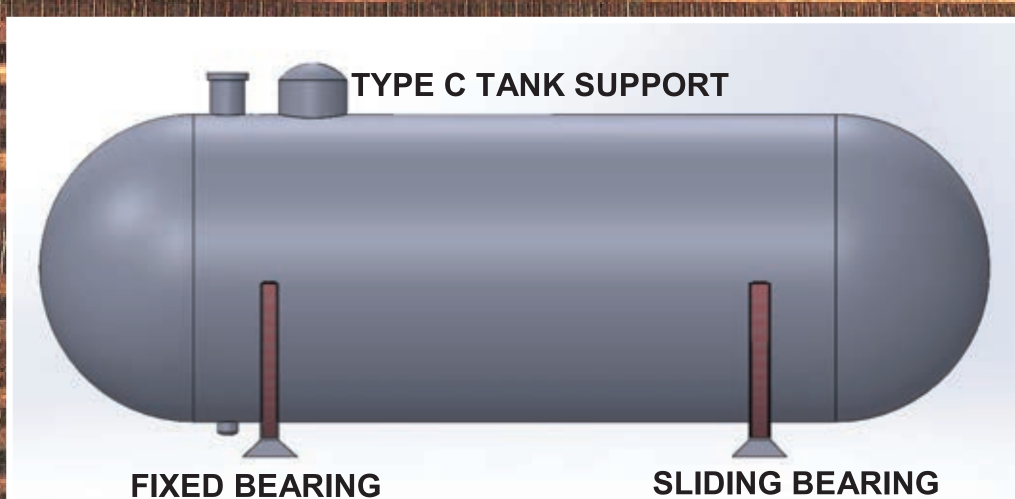

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28 pages essential LNG news!

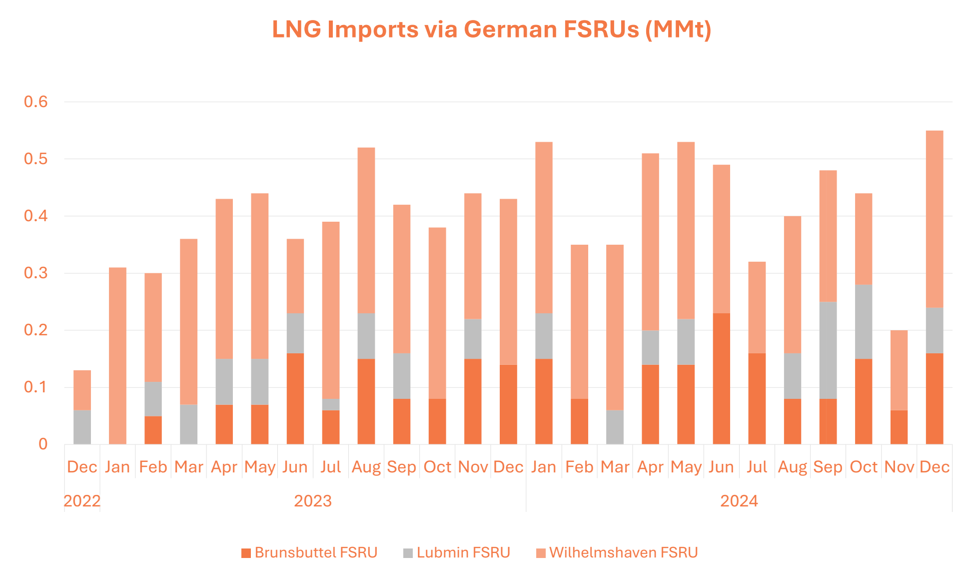
February 2025

In this issue:

Germany's LNG terminals: Security buffer or economic burden?

Germany's large-scale FSRU expansion aims to bolster European energy security. Whilst high operational costs, uneven utilisation and environmental concerns have triggered opposition, Europe's transitioning energy landscape mandates energy security enhancements, writes our Markets Editor Dr Alexander Wilk.

Russia's invasion of Ukraine precipitated a severe disruption in European energy markets, compelling Germany to initiate an extensive buildout of FSRU capacity. This infrastructure development, while conceived as a strategic imperative for energy security, has drawn substantial criticism regarding its economic viability and long-term strategic value.



Source: LNG Journal

Emergency response

In response to the cessation of Russian pipeline gas supplies, German federal authorities implemented an expedited regulatory framework that shortened standard environmental compliance procedures in 2023 dubbed 'The New German Pace'. The strategic objective encompassed the establishment of FSRU capacity in a bid to compensate for the annual shortfall of 45 billion cubic metres (bcm) previously supplied via Russian pipelines. The implementation strategy further incorporated plans for equivalent capacity through future conventional onshore terminals, representing an unprecedented expansion of domestic gas import capabilities by both German investors and the German government.

Operational performance

Data by Germany's federal energy regulator (Bundesnetzagentur) indicates that LNG terminal utilisation has achieved 8 percent of the country's aggregate gas imports in 2024. According to our data, the facilities at Wilhelmshaven, Brunsbüttel and Lubmin/Mukran took in 5.15mmt via 137 cargoes, mainly derived from the United States. Other sources were Angola, Norway and Qatar. This was up 0.37mmt (8 percent) year-on-year. It also represents aggregate capacity utilisation of roughly 52 percent based on 9.93mmt of total annual import capacity for the three terminals at the time of writing.

Speaking to Bloomberg, Spark Commodities highlighted that Germany's terminals have a structural disadvantage to other European facilities as they were more expensive to deliver to according to Spark's assessment of their variable costs. Among other variables, these include fuel gas losses due to power consumption needed for the process of turning LNG back to gas. Due to the open loop systems employed by FSRUs, these costs are particularly high in the winter as the sea water used to slowly reheat gas prior to injection is too cold. It would have to be preheated with more of the delivered gas than usual, which drives up costs. During particularly cold periods, this circumstance can lead to no delivery slots being offered by the terminal. Spark Commodities highlighted that this unused capacity indicates Germany's FSRU terminals are operating below optimal economic thresholds.

A comparative analysis of regasification cost structures across European terminals reveals significant operational cost disparities. Empirical data from Spark Commodities and LNG Journal research demonstrates that German FSRUs often operate at substantially higher estimated total costs than established European terminals. The differential is particularly evident when comparing the Gate terminal in Rotterdam, operating at around EUR 0.546/MWh, with the Wilhelmshaven FSRU at EUR1.831/MWh based on variable costs as well as an assumed regas fee of EUR 0.50/MWh for the Gate terminal and the average slot auction price of EUR 0.64/MWh for Wilhelmshaven and Brunsbuttel in October 2023. This cost structure differential materially impacts the competitive position of German terminals within the European gas market.

Security priority

Germany's Federal Ministry for Economic Affairs and Climate Action has always maintained that the primary function of these facilities is to provide strategic energy security rather than achieve commercial optimisation. This policy position aligns with international precedent in FSRU deployment, where average utilisation rates approximate 45 percent globally, according to our data and calculations. Notably, this is a 15pp increase from the 30 percent we saw two years ago. Comparative analysis with Brazilian and Indonesian FSRU

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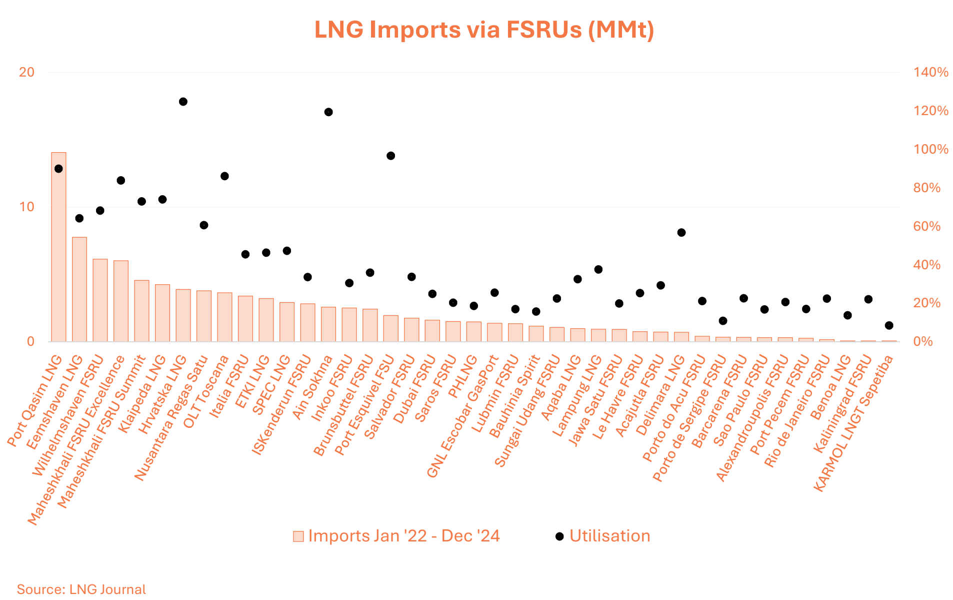


operations provides instructive parallels, where infrastructure utilisation is subordinate to strategic energy security considerations. The Brazilian model demonstrates the value of FSRU capacity during hydroelectric generation constraints, while Indonesia's archipelagic geography necessitates distributed LNG import capability, for example.

Gas consumption

Bundesnetzagentur data also highlights that gas utilisation among Germany's largest industrial gas consumers with an annual consumption of more than 1.5 GWh grown by almost 6.5 percent year-on-year in 2024. Gas consumption among the surveyed group of 40,000 entities only lagged 2023 volumes in February, March and August by 55, 12 and 18 GWh/day, respectively, whilst in the remaining months they grew by the median figure of 80 GWh/day. During the winter months, the year-on-year difference could be as high as 317 GWh/day. Whilst 2024 gas consumption still trailed the average of 2018-2021, the year-on-year growth indicates that natural gas to date has retained its strategic significance.

European integration

Russia's invasion of Ukraine highlighted the pan-European importance of secure energy infrastructure and energy market integration. Germany's new FSRU terminals are a cornerstone of the European Union's strategy to diversify gas sources, strengthen regional resilience, and mitigate future supply disruptions – evidenced by the Commission's recent ascent to allow German state aid for them. These terminals, designated by EU legislation as regionally significant, allow gas to be channelled to landlocked Eastern European member states and reflect the principle of European solidarity. In southern Europe, facilities such as the Saros and Alexandroupolis terminals offshore Turkey and Greece, as well as Croatia's Hrvatska terminal, serve similar strategic objectives for EU Member States without direct sea access.

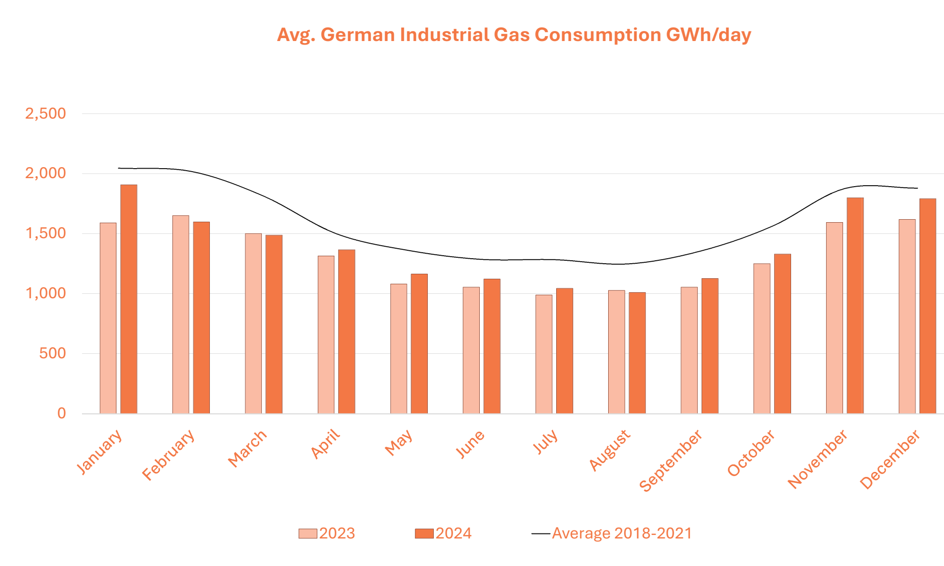
The Deutsche Ostsee terminal at Mukran on the Island of Rügen exemplifies this regional dimension: its injection capacity of up to 13.5 bcm per year, via a 16 GWh/h throughput rate, reinforces the EU's gas supply options. With direct links to German and Czech transmission systems, the terminal could theoretically cover Austria's annual gas consumption, according to its operator, Deutsche ReGas. This is particularly relevant now that the final Naftogaz–Gazprom contract expired at the start of 2025, ending the remaining 10.95 bcm of Russian pipeline gas flows to the EU via Ukraine. Although modest overall, these volumes are still likely to require replacement from elsewhere. Florence Schmit, energy strategist at Rabobank, told the Financial Times she does not see "any big alternative supplies via [other] pipelines. I think most of it will need to be replaced by LNG."

Professor Stephan Knabe, Chairman of Deutsche ReGas's Supervisory Board, underscored the "European solidarity" his (and presumably Germany's other terminals) represent, while Klaus Müller, President of the Bundesnetzagentur, has similarly stressed in the past the need for surplus capacity to be in a position to cover unexpected disruptions and demand spikes.

The European integration and energy security perspective has further come to the forefront recently as both coalition parties of the Norwegian government vowed to oppose the renewal of Norway's electricity interconnectors with Denmark in the next parliamentary election in September this year, according to reporting by the Financial Times. The idea of a renegotiation of existing interconnectors with the UK and Germany has also been floated. Although Norway is not an EU Member State, it is a key energy partner via the European Economic Area, and its hydropower exports form part of Europe's diversified energy mix. The coalition's calls have raised alarms about "energy nationalism", with EU diplomats voicing concern over a potential cut to power supply via Norwegian interconnectors in a time of need. In June 2022, the EU and Norway affirmed their commitment to "strengthening energy cooperation" in response to Russia's Ukraine invasion. However, Norwegian political parties have since blamed the country's close ties to the EU energy market as accelerating domestic electricity price inflation.

REPowerEU

It is against this backdrop that Germany secured approval for up to EUR 4.96 billion in state aid to operate four FSRU



terminals. These floating units, managed by the state-owned Deutsche Energieterminal in Brunsbüttel, Stade, and Wilhelmshaven (two units), are conceived as interim solutions to bolster energy security at a time of transition.

The support package covers operating losses until 2033, reflecting the finite operational lifespan of the floating terminals. It also indicates the European Commission has deemed the scheme vital to contain serious economic disruption and to ensure gas supply security, in line with REPowerEU's overarching aims. REPowerEU are a set of even more ambitious goals agreed by Member States in 2022. They build on the original 'Fit for 55' plan to slash energy consumption by more than a third by 2030, both to achieve more ambitious climate goals and to eliminate dependency on Russian energy supplies. This would also entail a drastic cut to EU LNG demand. The EU Agency for the Cooperation of Energy Regulators (ACER) projected in April 2024 that full achievement of REPowerEU would lead to a drop in the bloc's gas demand by roughly 44 percent, effectively squeezing out LNG requirements beyond a slither of spot volumes to balance the market. In contrast, the original 'Fit for 55' goals would result in a much shallower reduction of about 1 percent annually and even encompass a slight demand increase in 2025.

However, Columbia University's REPowerEU Tracker shows that progress towards REPowerEU targets has been mixed. Whilst it highlights notable success in achieving short-term objectives – such as diversifying gas imports and meeting voluntary consumption reduction targets – it also flags more sobering long-term challenges. The Tracker deems the EU to be lagging in scaling up wind capacity, biomethane output and renewable hydrogen production, all of which are important for meeting the EU's gas demand reduction outlook by 2030.

This can help explain why Member States have been more cautious about ambitious goals than the Commission's initial proposals, which resulted in the reduction of the originally proposed legally binding target for energy efficiency gains from 13 percent to 11.7 percent. Not only does this move reflect a pragmatic response to current market and geopolitical uncertainties, it also underlines the difficulty of balancing immediate energy security needs and economic growth with climate and sustainability goals. For example, the Commission has acknowledged in its REPowerEU proposal of 2021 that 75 percent of EU building stock has poor energy performance whilst energy demand by EU data centres was projected to increase by almost a third to 98.5 TWh by 2030 even before the prominent roll-out of AI products.

Infrastructure utilisation across Europe

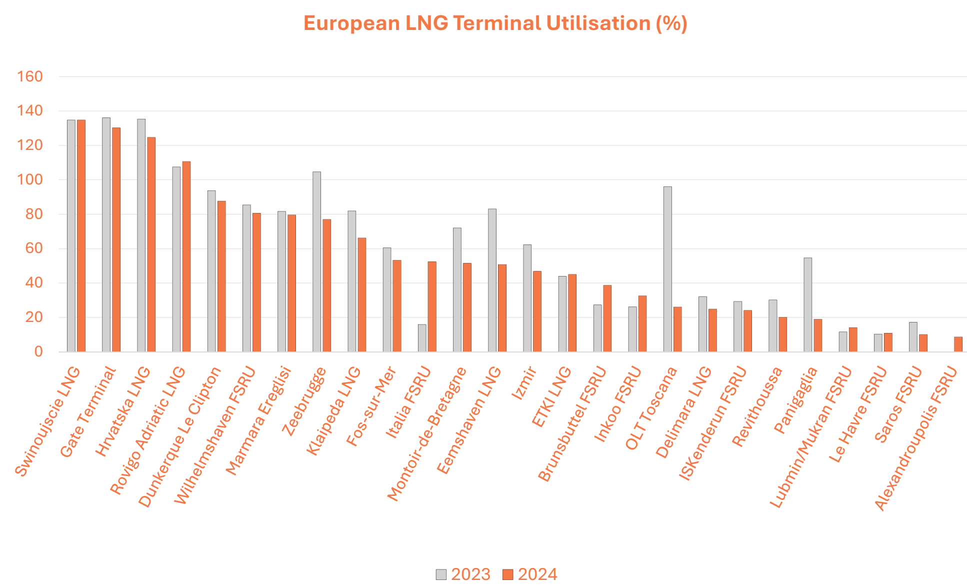
A year-on-year drop in LNG terminal utilisation across the European Union – our data shows a reduction of 8pp to an average of 55 percent in 2024 from 63 percent in 2023 – is frequently used as an argument against enhancing LNG import capacity across Europe. However, the recent decrease notwithstanding, utilisation remains elevated above pre-2022 levels of 30-50 percent.

Moreover, our data shows significant disparity between different terminals' utilisation rates, indicating structural shortfalls in what is the nominally integrated EU gas market. Previously, analysis by the Institute of Energy Economics at the University of Cologne (EWI) indicates that existing European terminals and cross-border pipelines do not always facilitate higher gas throughput where it is needed. Physical bottlenecks, divergent price structures, and national priorities can limit the practical redistribution of gas, including between France and Germany. Previously, France's own gas needs have been elevated by temporary nuclear power shortfalls due to drought, further complicating the flow of LNG from its terminals to neighbouring states.

Such structural imbalances help to explain why Germany, despite criticisms of underused capacity, continues to add new terminals. Supporters argue that a robust domestic LNG network relies on some redundancy when existing European nodes are constrained or when regional demand spikes. Critics, however, see these investments as excessive in light of current utilisation rates, fearing economic inefficiency and the risk of locking in gas use at the expense of decarbonisation.

Legal challenges

The imminent arrival of additional FSRU facilities – such as the second terminal in Wilhelmshaven and a new site in Stade – have brought the debate over balancing cost-effectiveness, decarbonisation goals and Europe's precarious geopolitical



Source: LNG Journal
UK, Spanish and Portuguese terminals not listed due to lack of interconnectivity

context to a head in Germany. Environmental organisation Deutsche Umwelthilfe (DUH) brought a legal challenge against the accelerated approvals of Germany's LNG terminals as they would jeopardise environmental standards. However, Germany's highest administrative court has upheld approvals granted under the LNG Acceleration Act such as the one for the Lubmin/Mukran terminal: the court deemed it an urgent, lawful contribution to national energy security.

Concluding thoughts

The empirical evidence presents a nuanced picture of Germany's LNG infrastructure strategy. Whilst the terminals' 52 per cent utilisation rate and substantially higher operating costs compared to established facilities like the Gate terminal in Rotterdam indicate nominal economic inefficiency, such metrics tell only part of the story. Environmental groups have intensified their opposition not only to future expansion but also to existing infrastructure, as evidenced by legal challenges to the Lubmin/Mukran terminal. However, the court's decisions to uphold accelerated approvals effectively reflect the continuing primacy of energy security concerns. The growth in German industrial gas consumption — up 6.5 percent year-on-year in 2024 — coupled with the recent expiration of the remaining Naftogaz–Gazprom contract underscores the continuing strategic importance of secure gas supplies.

Germany's approach to LNG infrastructure reflects a calculated trade-off between economic optimisation and strategic resilience. The higher costs associated with FSRU operations, whilst significant, represent the premium paid for energy security in an increasingly unpredictable geopolitical landscape. This is particularly relevant given the struggles to achieve REPowerEU targets for reducing gas consumption and expanding renewable alternatives. The delayed progress in scaling up wind capacity, biomethane output and renewable hydrogen production suggests that natural gas will retain its significance in Germany's energy mix longer than initially anticipated.

Moreover, the apparent overcapacity in German LNG infrastructure serves a broader European purpose. The limitations of the EU's integrated gas market — evidenced by bottlenecks between regions and divergent national priorities — justify maintaining redundant capacity. This becomes especially pertinent as established energy partnerships face political pressures, exemplified by Norway's evolving stance on electricity interconnectors.

Rather than viewing Germany's LNG terminal buildout as either a success or failure, it is more accurately understood as a pragmatic response to concurrent challenges: maintaining industrial competitiveness, ensuring energy security and managing the transition toward renewable alternatives. Whilst energy efficiency initiatives have shown meaningful results, both the Federal Government's continued support and the European Commission's endorsement of state aid suggest that these gains have not yet diminished the strategic value of maintaining surplus LNG import capacity. The higher operational costs and seemingly excess capacity are not policy missteps but rather the calculated cost of ensuring energy resilience during a period of profound transition in European energy markets. ■

India blends LNG with domestic gas as demand doubles by 2040

India is poised to snap up big parts of the substantial volume of uncontracted LNG from the Middle East. Buying interest is on the rise as the Indian government allows utilities to blend LNG with domestically produced gas in a bid to make it more affordable for power generation, compared with coal; our Correspondent Anja Karl investigates.

"Watch out of freely available LNG" seems to be the motto of Indian commodity traders and large utilities. Looking ahead, Rystad's Kaushal Ramesh, Vice President Gas & LNG Research, expects savvy buyers to secure large parts of the uncontracted LNG production from Qatar, Oman and potentially Iran – at favourable terms. "The nation is well-positioned to attract aggressive targeting from Middle Eastern producers and offtakers," he said, anticipating nearly 100 million tons per annum (mtpa) of Middle East LNG will remain uncontracted by 2035.

As Asia's most rapidly growing power market, India is spearheading the region's forecast $3.3 trillion investment in power generation over the next 10 years. Analysts anticipates the region will add 1,840 GW of new capacity in the next five years, more than the rest of the world combined.

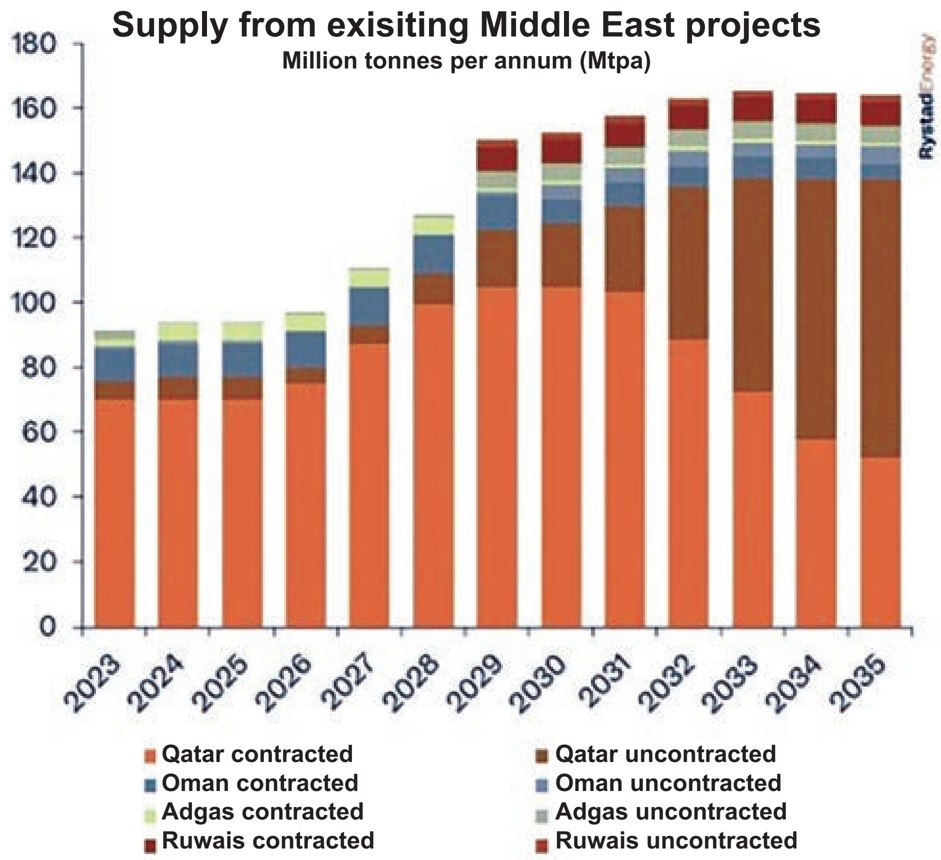
"Asia Pacific is critical to the success of the energy transition in the global power sector as it grows to over half of global electricity demand this year. India and China are at the forefront of renewables growth, but are also leading the world in coal power deployments," Alex Whitworth, head of Asia Pacific Power & Renewables Research at Wood Mackenzie, told a conference in Uttar Pradesh.

Though India already overtook Japan a decade ago as Asia's second largest power market, its growth potential is still vast. Electricity demand on the Indian subcontinent doubled in the last 12 years, and this trend is likely to replicate as strong economic growth is set to continue, spurring LNG imports.

Tricky buyers

Some potential pitfalls should be taken into consideration: Indian LNG buyers have a reputation for re-negotiating or even abandoning near-complete deals, which creates uncertainty for suppliers. Buyers' preference for flexibility and cost-effectiveness over long-term commitments highlights India's focus on securing the best prices for its consumers in a volatile global market – but such actions can put a spanner in prospective LNG import projects and limit the growth potential of the Indian gas market.

Delays at infrastructure build-out, in fact, has been hampering the



development of India's overall gas and power generation sector. Regasification terminals have, so far, remained concentrated in the western part of the country, and efforts to expand the gas pipeline network to other regions have been inconsistent.

"Slow progress is due to regulatory hurdles, challenges in securing investments, difficult terrain, and competing priorities," Mr Ramesh said, "as India channels significant resources into renewable energy development alongside its gas infrastructure."

Bird's eye view of the Chhara LNG import terminal in India's Gujarat state

Chhara LNG – another import option

Optionality increases as to where Indian LNG buyers can get cargoes delivered to: India's Hindustan Petroleum Corp (HPCL) on January 14 commissioned its new Chhara terminal in Rajasthan. With a nameplate capacity of 5 mtpa and situated in western India, Chhara is HPCL's sixth regas terminal – developed to source long-term gas supply for adjacent power stations. Phase 2 of the terminal envisages the construction of an additional jetty.

Built at a cost of INR 47.50 billion, equivalent to $0.55 billion, the regas terminal includes berthing slots, marine unloading and regas facilities along with storage, LNG road tanker loading, and supply of regasified LNG to the Indian gas grid. HPCL LNG said it wants to operate the terminal on a tolling model which is open to third-party users, through long-term capacity booking contracts and master regas agreements for spot cargoes. According to HPCL, the terminal will help enhance India's energy security and support the national target of increasing the share of natural gas in the energy mix to 15 percent by 2030.

Commissioning of Chhara LNG comes on the heels of a similar development in Gujarat state in late December when Nebula Energy's AG&P signed a heads of agreement (HOA) with Swan Energy Ltd (SEL) to form an LNG logistics venture in India. In this context, Nebula Energy and acquired a stake in the 10-mtpa Swan LNG regas terminal.

Firm off-takers lined up

As for Chhara LNG, the state-owned operator HPCL received a "good response" to its expression of interest (EoI) with several parties ready to offtake firm volumes for 15 years. One industry source said it is seeking "one cargo per month for delivery starting no later than 2025 or early 2027, priced on a Brent-indexed basis." Following a reassuring round of EoIs, more than 20 prospective suppliers were shortlisted – including Shell, TotalEnergies and Vitol.

Offtakers include electric utilities, major industries and refineries: The Indian utility Torrent Power and state-owned Gujarat State Petroleum Corp (GSPC), for instance, strives to source long-term LNG supply from 2026 or 2027. Torrent Power is seeking to enter a firm gas supply and purchase agreement for about 1 mtpa with a tenure of 10 years, while GSPC looks for a 10 -15 year supply deal for a volume of 0.5 mtpa.

> *Notwithstanding India's rising options to get LNG landed at its shores, the subcontinent is facing long-term energy shortages*

Stable LNG supply is also of the essence to meet fuel requirements of two refineries and a new 180,000 barrels per day (bpd) refinery and petrochemical factory, currently under construction in Rajasthan.

Insufficient gas supply

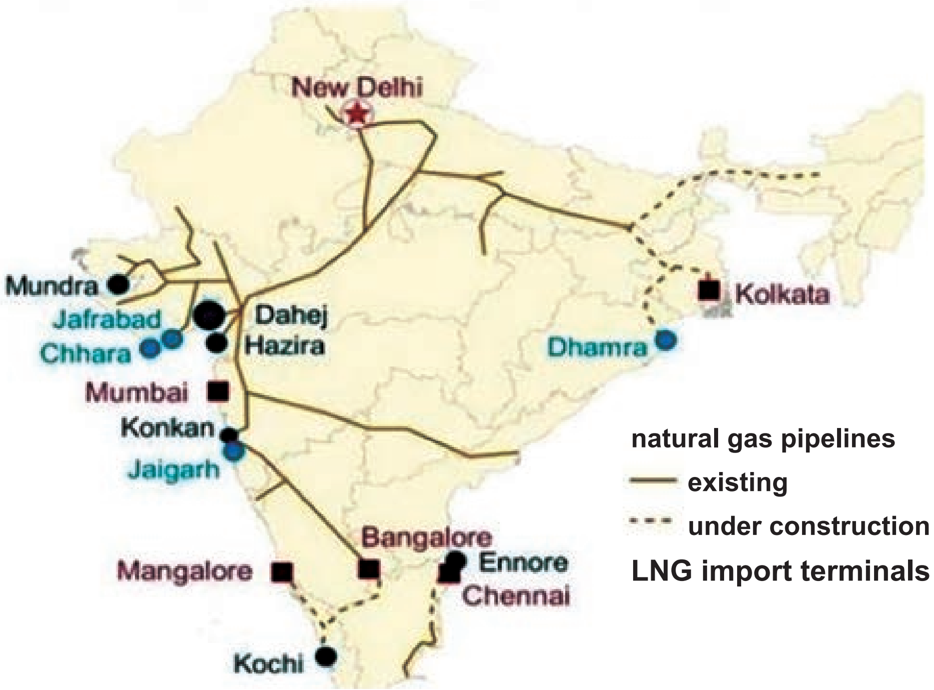
Notwithstanding India's rising options to get LNG landed at its shores, the subcontinent is facing long-term energy shortages: Come 2040, the country's total gas consumption is forecast to double to almost 114 billion cubic metres (bcm). The anticipated 51 percent jump in domestic production to 36.7 bcm by the end of this year will not suffice to meet India's growing energy hunger and the world's most populous nation hence has to heavily rely on imported LNG and other commodities.

Long-term and often oil-indexed LNG contracts – extending way into the 2030s and beyond – help shield India from global price fluctuations and ensure a steady stream of cargoes shipped to Indian shores. Through these LNG offtake accords, Indian buyers do not only strengthen its energy security – these contractual arrangements also facilitate a swift exit from more emission-intensive fuels like crude oil, mazut and thermal coal.

India's heavy reliance on coal has become apparent during the summer 2024 heatwaves, which temporarily propelled up coal-burn to meet peak electricity demand. Natural gas, on the other hand, currently accounts for just 2 percent of the country's power mix – and in fact, coal-burn is not projected to start falling this side of 2040.

On the other hand, analysts doubt that rising gas-burn in the power sector will drive near-term LNG imports. Utilities' future fuel choices largely hinge on government policies to introduce carbon pricing – as well as capital costs of renewables.

India's LNG and gas pipeline infrastructure



Slow coal exit

Home to some of the lowest cost renewables in the world, India rapidly developed large-scale wind and solar project which pushed the country's renewables share of power generation to 22 percent in 2022. But despite a 2070 carbon neutral target, India is still investing heavily in new coal power to support economic growth, with a pipeline of over 50 GW of projects planned and under construction.

"Currently, fossil fuels (mainly coal) still provide 75 percent of India's power supply but that share is declining steadily. According to the government's ambitious policy goals, India's per capita power sector emissions are meant to peak in the next decade at less than half of where most western markets were at a similar level of development," Whitworth pointed out.

But it may not be enough: In the next decade alone, India will need $350 billion in power generation investment to meet growing demand, according to Wood Mackenzie projections. While cheap renewables and technology advances herald a continued renewable build-out in India, the actual scale and speed of growth hinges on grid investments and the reform of pricing mechanisms to attract investment.

Power sector CO2 emissions in India soared from 850 million tons in 2015 to an estimated 1,200 million tons in 2023, and this figure is expected to rise further to 1400 Mt by 2030. Renewables, combined with energy storage, are hence deemed to be "paramount" for the Asian powerhouse to transition to a truly low carbon power system. ■

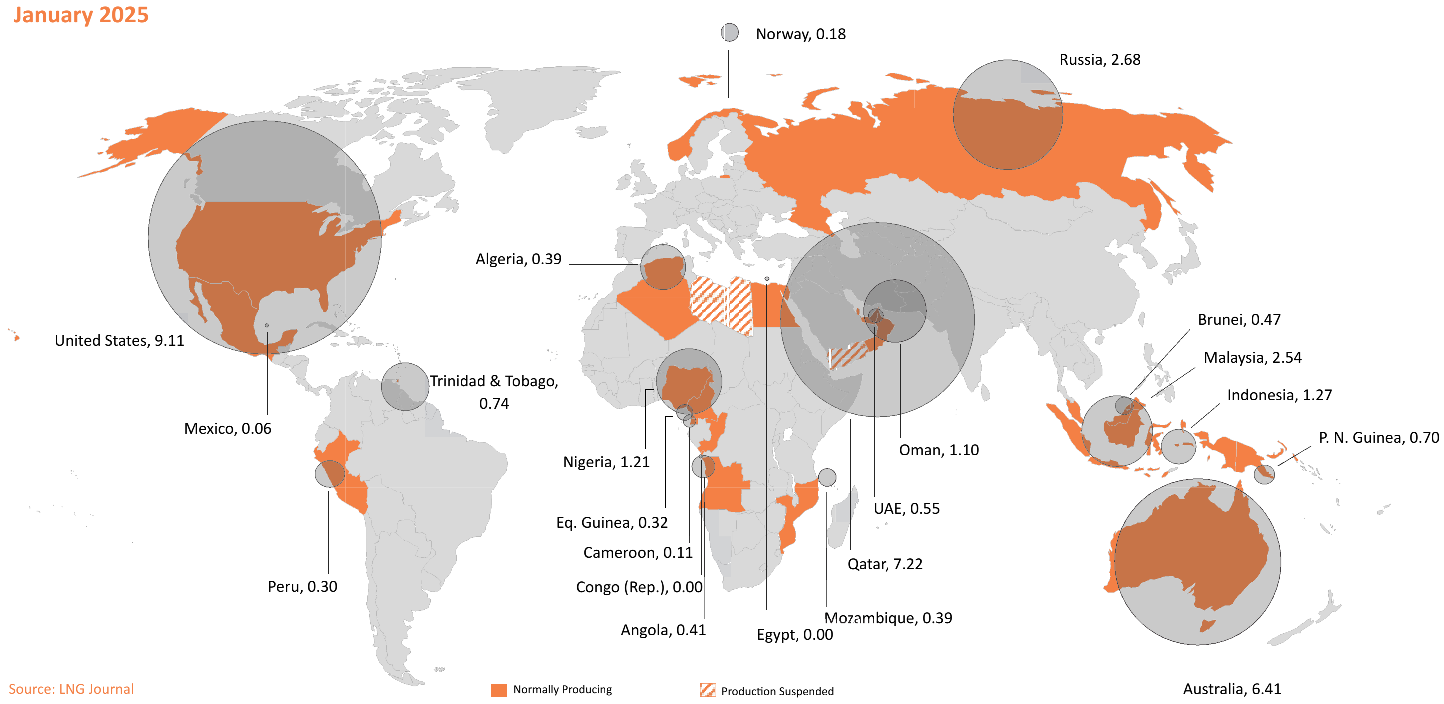
Global LNG trade sees month-on-month dip in January

Our January data showed a dip in LNG trade driven by lower Pacific output. Meanwhile, global demand remained broadly steady, our Market Editor Dr Alexander Wilk reports.

According to our data, global LNG trade in January amounted to 36.16mmt, down by 1.35mmt (-4 percent) from 37.51mmt in December.

Global LNG Exports (MMt)

January 2025

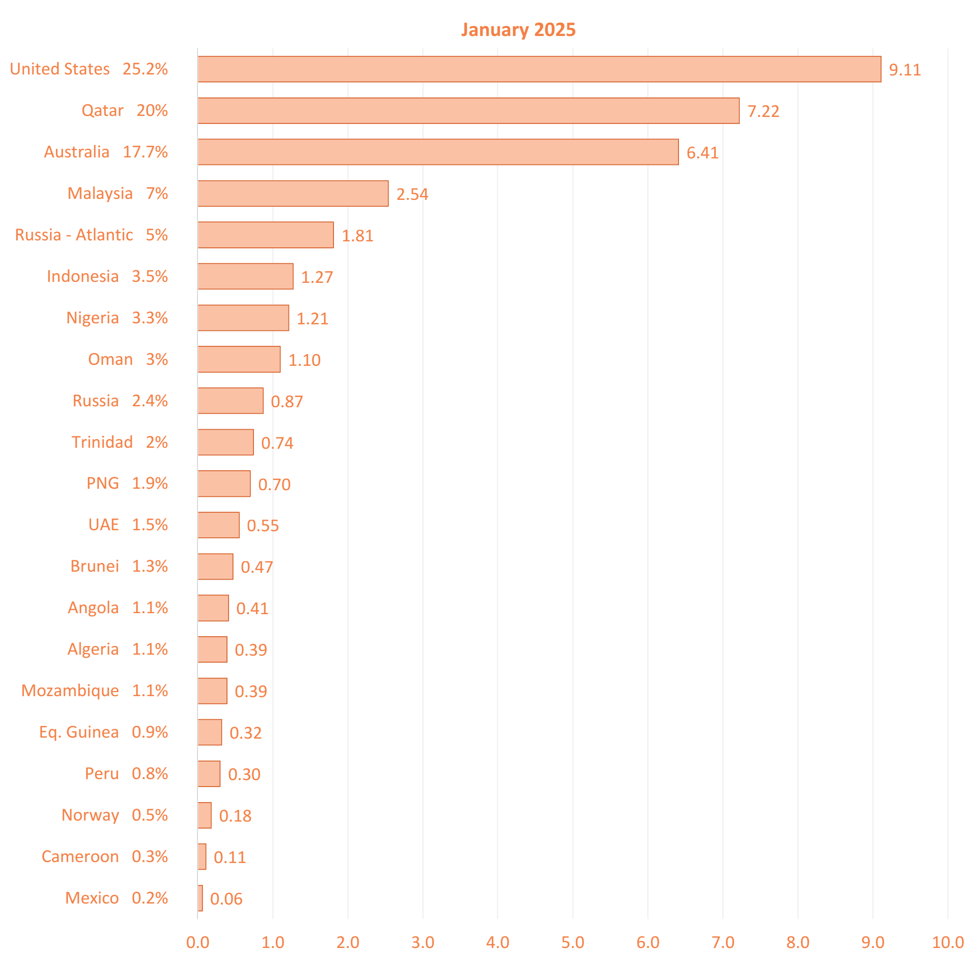


The Pacific Basin drove the month-on-month decrease, with exports down by 1.42mmt (-10 percent) to 12.95mmt from 14.37mmt in December. Australia, the region's largest exporter by installed capacity, saw shipments drop by 0.65mmt (-9 percent) to 6.41mmt from 7.06mmt, with month-on-month decreases across multiple plants, including Australia Pacific LNG, NWS LNG and Prelude FLNG.

Atlantic Basin exports were also down, with overall shipped LNG falling by 0.70mmt (-5 percent) to 14.34mmt from 15.04mmt in December. US exports remained the dominant force in the Basin but showed mixed performance, with total shipments increasing by 0.27mmt (3 percent) to 9.11mmt from 8.84mmt, led by Plaquemines LNG and Sabine Pass LNG. However, export decreases in Russia and Algeria, in particular, offset that growth.

In contrast, Middle Eastern LNG exports increased by 0.77mmt (10 percent) to 8.87mmt from 8.10mmt in December, underpinned by export growth at Qatar's Ras Laffan LNG.

Market Share & LNG Exports by Country (MMt)



Source: LNG Journal

Global LNG imports remained broadly stable at 37.25mmt in January, compared to 37.29mmt in December. European LNG demand continued to rise, alongside demand growth in the Americas. However, Pacific Basin LNG demand dropped, with imports down by 1.02mmt (-4 percent) to 22.87mmt from 23.89mmt, as major buyers – including China, India, Taiwan, South Korea, and Japan – collectively reduced their offtakes. Middle Eastern LNG demand increased by 0.09mmt (7 percent) to 1.38mmt in January, with annualised capacity utilisation averaging 26 percent. Egyptian and Kuwaiti demand saw moderate growth alongside Jordan's market return, while Pakistan's imports declined.

Export - Pacific Basin

In January, Pacific exports had accrued to 12.95mmt and had thus decreased by 1.42mmt (-10 percent) compared to December's total of 14.37mmt. Consequently, annualised capacity utilisation stood at 82 percent. Exports were thus also down by 0.56mmt (-4 percent) year-on-year.

Australia: Australian LNG exports decreased to 6.41mmt in January from 7.06mmt in December, down by 0.65mmt (-9 percent). Our data showed mixed performances with two facilities marking increases whilst seven plants saw lower volumes.

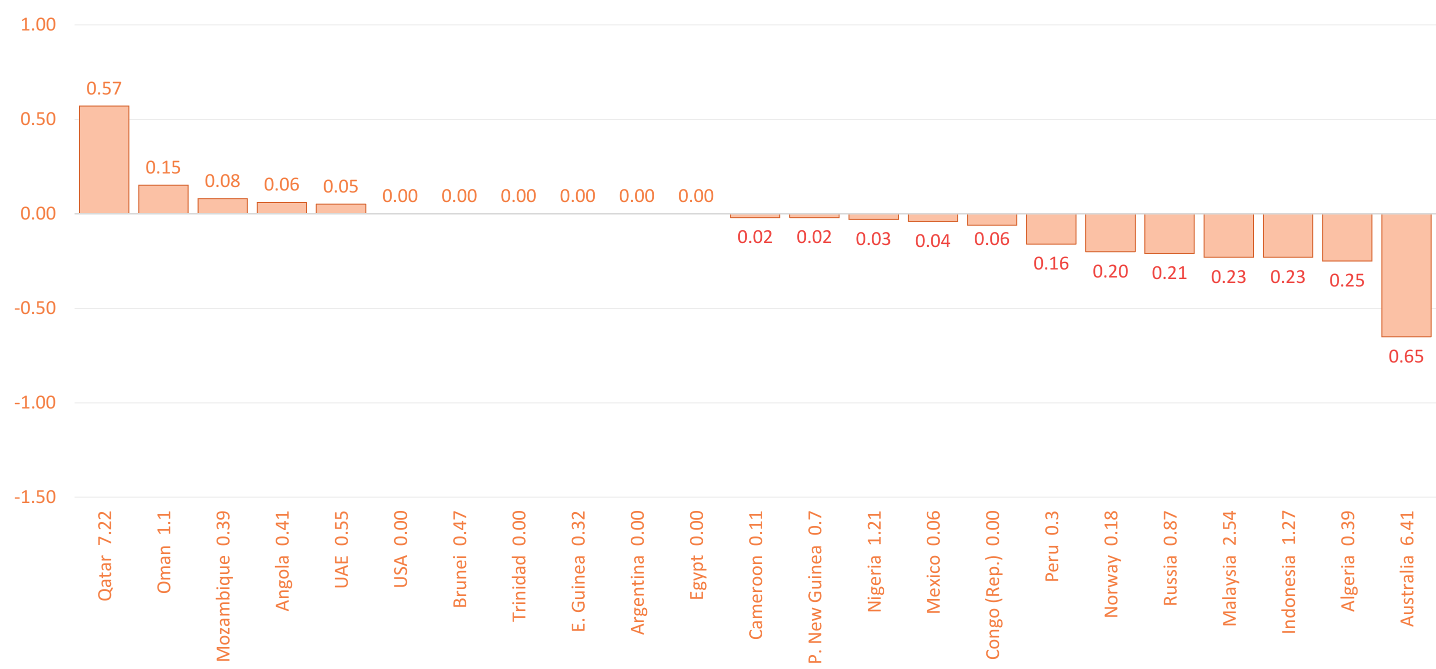
Queensland Curtis LNG delivered 0.79mmt in January, up from 0.75mmt in December with an increase of 0.04mmt (5 percent), whilst Ichthys LNG shipped 0.79mmt, up from 0.78mmt with a modest rise of 0.01mmt (1 percent). In contrast, Australia Pacific LNG shipped 0.74mmt in January, down from 0.93mmt with a decrease of 0.19mmt (-20 percent). NWS LNG delivered 1.00mmt, down from 1.13mmt with a reduction of 0.13mmt (-12 percent) and Prelude FLNG volumes moved down to 0.15mmt from 0.27mmt, showing a decrease of 0.12mmt (-44 percent). Gorgon LNG shipped 1.30mmt, down from 1.42mmt with a decrease of 0.12mmt (-8 percent), whilst Gladstone LNG delivered 0.49mmt, down from 0.59mmt with a reduction of 0.10mmt (-17 percent). Wheatstone LNG volumes moved down to 0.74mmt from 0.76mmt, marking a decrease of 0.02mmt (-3 percent) and Pluto LNG shipped 0.41mmt, down from 0.43mmt with a reduction of 0.02mmt (-5 percent).

Australian LNG exports to Northeast Asia saw overall decreases in January. Japanese imports moved down to

2.16mmt from 2.47mmt with a decrease of 0.31mmt (-13 percent), whilst Chinese imports fell to 1.61mmt from 2.38mmt with a reduction of 0.77mmt (-32 percent). South Korean volumes decreased to 1.09mmt from 1.29mmt, showing a reduction of 0.20mmt (-16 percent) and Taiwanese imports moved down to 0.49mmt from 0.54mmt with a decrease of 0.05mmt (-9 percent). In Southeast Asia, Thailand imported 0.29mmt in January after not being seen in the market with offtakes from Australia during December. Singapore volumes rose to 0.24mmt from 0.16mmt with an increase of 0.08mmt (50 percent) and Malaysian imports grew to 0.22mmt from 0.10mmt with a gain of 0.12mmt (120 percent). Moreover, Indonesia imported 0.06mmt after not being seen in the market with offtakes from Australia during December. India, however, was not seen in the market with offtakes from Australia in January, down from 0.07mmt during December. We were also tracking cargoes amounting to 0.25mmt that still had to declare their destinations within the Basin.

Incremental LNG Exports by Country (MMt)

January 2025



Source: LNG Journal

Southeast Asia: PNG LNG shipped 0.70mmt in January, down from 0.72mmt in December with a decrease of 0.02mmt (-3 percent). The plant's annualised capacity utilisation rate thus stood at 99 percent.

Japanese imports from PNG LNG moved down to 0.33mmt from 0.34mmt with a decrease of 0.01mmt (-3 percent), whilst Chinese volumes fell to 0.14mmt from 0.16mmt with a reduction of 0.02mmt (-13 percent). Taiwanese imports decreased to 0.08mmt from 0.22mmt with a reduction of 0.14mmt (-64 percent). However, South Korea returned to the market for PNG LNG volumes of 0.07mmt whilst we were still tracking a 0.08mmt cargo broadly headed for the Far East at the time of writing.

Indonesian exports decreased to 1.27mmt in January from 1.50mmt in December, down by 0.23mmt (-15 percent). Tangguh delivered 1.00mmt in January, up from 0.87mmt in December with an increase of 0.13mmt (15 percent). However, Bontang shipped only 0.17mmt, down from 0.43mmt with a decrease of 0.26mmt (-60 percent), whilst Donggi-Senoro LNG delivered 0.10mmt, down from 0.20mmt with a reduction of 0.10mmt (-50 percent). Accordingly, Bontang operated at 17 percent of annualised capacity utilisation, whilst Tangguh and Donggi-Senoro LNG produced at 103 percent and 59 percent, respectively.

Malaysian exports decreased to 2.54mmt in January from 2.77mmt in December, down by 0.23mmt (-8 percent). PFLNG 1 volumes remained unchanged at 0.06mmt between December and January, whilst Malaysia LNG delivered 2.28mmt, down from 2.31mmt with a decrease of 0.03mmt (-1 percent). PFLNG 2 shipped 0.20mmt, down from 0.40mmt with a reduction of 0.20mmt (-50 percent).

Brunei LNG volumes remained unchanged at 0.47mmt between December and January. The plant's annualised capacity utilisation rate thus also remained at 77 percent. Japanese imports from Brunei LNG moved up to 0.33mmt from 0.28mmt with an increase of 0.05mmt (18 percent), whilst Taiwanese volumes decreased to 0.07mmt from 0.14mmt with a reduction of 0.07mmt (-50 percent). South Korea was not seen in the market with offtakes from Brunei in January, down from 0.05mmt during December, whilst we were still tracking a 0.07mmt cargo broadly headed for the Far East.

Russia, Peru & Mozambique: Sakhalin-2 LNG shipped 0.87mmt in January, down from 1.08mmt in December with a decrease of 0.21mmt (-19 percent). However, the plant's annualised capacity utilisation rate still stood at 107 percent.

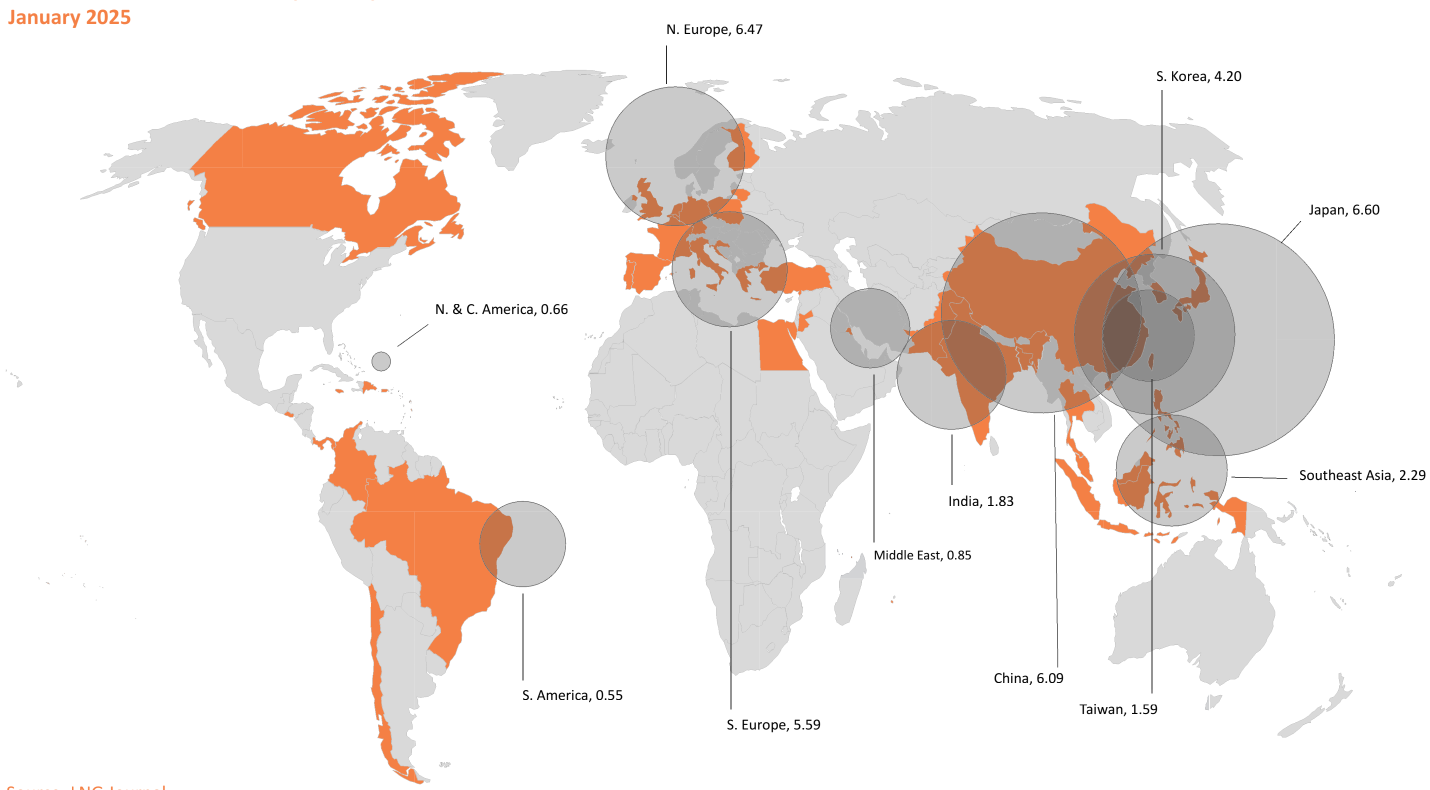
Japanese imports moved down to 0.47mmt from 0.54mmt with a decrease of 0.07mmt (-13 percent), whilst Chinese volumes halved to 0.18mmt from 0.36mmt. South Korean imports, however, rose to 0.22mmt from 0.18mmt with an increase of 0.04mmt (22 percent).

Pampa Melchorita LNG shipped 0.30mmt in January, down from 0.46mmt in December with a decrease of 0.16mmt (-35 percent). The plant's annualised capacity utilisation rate thus stood at 79 percent.

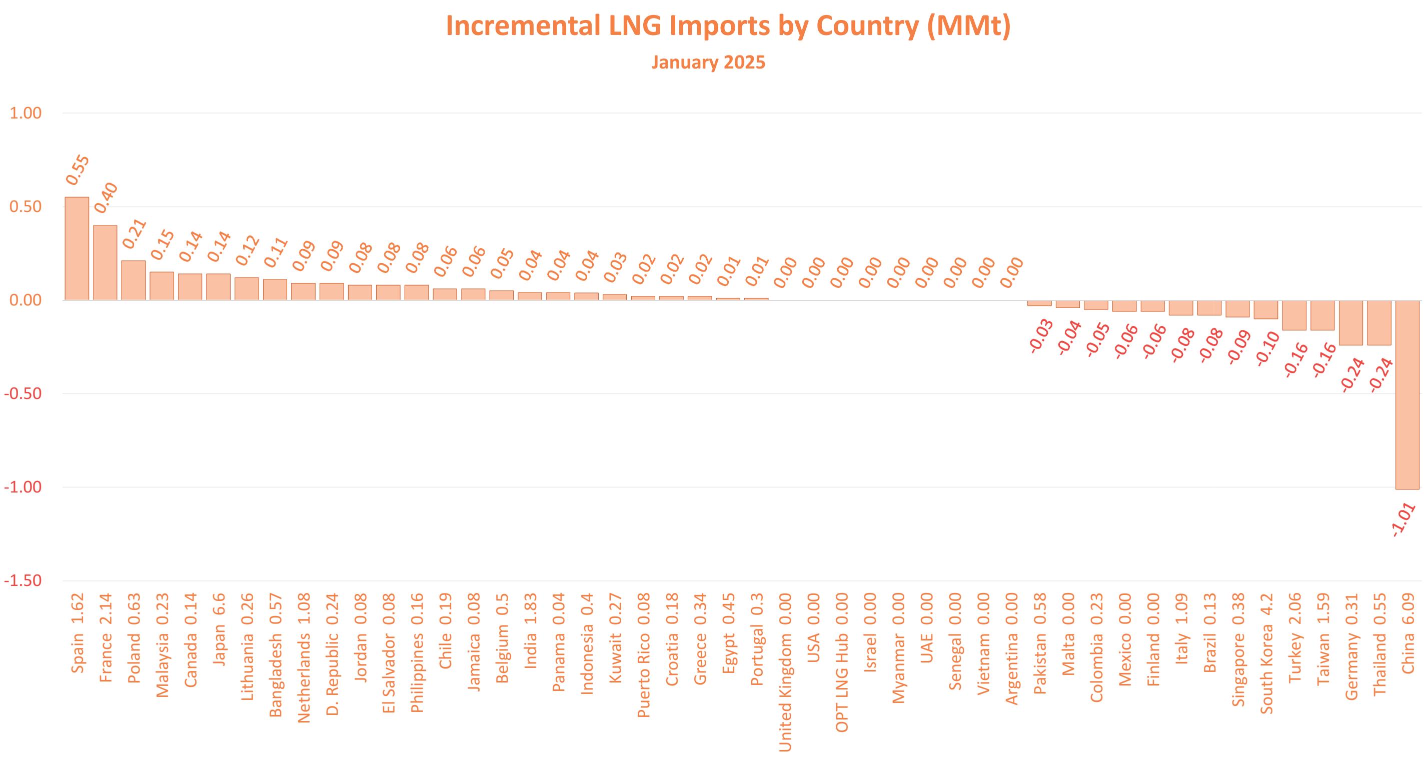
Japan returned to the market for

Global LNG Imports (MMt)

January 2025



Source: LNG Journal



Source: LNG Journal

Peruvian LNG with a 0.07mmt cargo whilst South Korean volumes halved to 0.08mmt from 0.16mmt. Canada, China, El Salvador and Spain were not seen in the market with offtakes from Peru in January, down from their total of 0.38mmt in December. We were also still tracking 0.15mmt broadly headed for Pacific destinations at the time of writing.

Mozambique's Coral Sul FLNG increased its production to 0.39mmt in January from 0.31mmt in December, showing growth of 0.08mmt (26 percent). The plant's annualised capacity utilisation rate reached 135 percent. Mozambican exports to China did not reoccur in January, down from 0.14mmt in December. However, exports to India and Japan remained steady via one cargo of 0.08mmt each, whilst Thailand imported 0.08mmt, up 0.01mmt (14 percent) from December. Singapore also increased its imports to 0.07mmt, up 0.05mmt (250 percent). We were also tracking a 0.07mmt cargo likely en route to a European destination.

Atlantic Basin

Alongside lower output in the Pacific, the Atlantic Basin's overall shipped LNG decreased by 0.70mmt (-5 percent) to 14.34mmt in January from 15.04mmt in December. This translated into annualised export capacity utilisation of 69 percent for the Basin. Accordingly, exports were down by 0.71mmt (-5 percent) year-on-year.

North Africa & Europe: The amount of LNG shipped from within its north-eastern part - comprising the EEA, Russia and North Africa (and not including re-exports) - amounted to 2.38mmt in January and thus saw exports decrease by 0.77mmt (-24 percent) from 3.15mmt in December.

Russian Atlantic Basin exports decreased by 0.32mmt (-15 percent) to 1.81mmt in January from 2.13mmt in December. Yamal LNG volumes fell to 1.81mmt from 1.94mmt, showing a reduction of 0.13mmt (-7 percent), whilst Portovaya LNG was not seen in the market during January, down from 0.19mmt in December. The annualised capacity utilisation rate for Yamal LNG stood at 122 percent. Arctic LNG 2 was not seen in the market.

Russia's Atlantic LNG exports to France grew to 0.70mmt, up 0.10mmt (17 percent) from December, whilst Chinese imports rose to 0.32mmt, up 0.17mmt (113 percent). Spanish volumes decreased to 0.32mmt from 0.50mmt, showing a reduction of 0.18mmt (-36 percent), and Belgian imports fell to 0.20mmt from 0.40mmt, down 0.20mmt (-50 percent). Volumes of 0.16mmt remained in Europe with their final destination yet to be confirmed, whilst Dutch volumes decreased slightly to 0.11mmt, down 0.01mmt (-8 percent). Italy, Portugal and Turkey were not seen in the market in January, down from 0.06mmt, 0.07mmt and 0.07mmt respectively in December, whilst no cargoes were directed to Taiwan down from 0.08mmt in December.

Norway's Snohvit LNG reduced its production to 0.18mmt in January from 0.38mmt in December, showing a decrease of 0.20mmt (-53 percent). The plant's annualised capacity utilisation rate thus also more than halved to 50 percent. Lithuanian imports from Norway increased to 0.11mmt, up 0.05mmt (83 percent) from December, whilst French volumes grew to 0.07mmt, up 0.01mmt (17 percent). The Netherlands, Poland and Turkey were not seen in the market in January, down from 0.12mmt, 0.08mmt and 0.06mmt respectively during the previous month.

Algerian LNG exports decreased by 0.25mmt (-39 percent) to 0.39mmt in January from 0.64mmt in December. The Skikda LNG plant increased its shipments to 0.08mmt from 0.05mmt, showing growth of 0.03mmt (60 percent), whilst Arzew volumes fell to 0.31mmt from 0.59mmt, down 0.28mmt (-47 percent). The plants operated at 12 percent and 18 percent of their annualised capacity utilisation respectively.

West Africa: Concurrently, West African LNG flows were down slightly by 0.05mmt (-2 percent) to 2.05mmt from 2.10mmt in December.

Angola LNG grew its deliveries to 0.41mmt from 0.35mmt, showing an increase of 0.06mmt (17 percent), whilst EG LNG maintained its volumes at 0.32mmt. However, Cameroon FLNG reduced its shipments to 0.11mmt from 0.13mmt, down by 0.02mmt (-15 percent), and Bonny Island volumes fell to 1.21mmt from 1.24mmt, a decrease of 0.03mmt (-2 percent). Moreover, Congo FLNG was not seen in the market in January, down from 0.06mmt in December. The facilities operated at 93 percent, 102 percent, 54 percent and 64 percent of their annualised capacity utilisation respectively.

Spanish imports from West Africa increased to 0.40mmt, up 0.24mmt (150 percent) from December, whilst Dutch volumes grew to 0.29mmt, up 0.14mmt (93 percent). Volumes directed to Turkey fell to 0.21mmt from 0.24mmt, down 0.03mmt (-13 percent). British imports rose to 0.19mmt, up 0.12mmt (171 percent), whilst Belgium and Thailand entered the market with 0.15mmt each.

Portuguese volumes increased slightly to 0.15mmt, up 0.01mmt (7 percent). Italian imports decreased to 0.08mmt from 0.15mmt, down 0.07mmt (-47 percent). Notably, the Philippines took in a rare West African cargo of 0.08mmt whilst Indian volumes fell to 0.06mmt from 0.21mmt, down 0.15mmt (-71 percent), and Chinese imports decreased to 0.05mmt from 0.22mmt,

Alongside lower output in the Pacific, the Atlantic Basin's overall shipped LNG decreased by 0.70mmt (-5 percent) to 14.34mmt in January from 15.04mmt in December

showing a reduction of 0.17mmt (-77 percent). Meanwhile, Puerto Rico and the OPT Hub on the US Virgin Islands each took in 0.05mmt, whilst French volumes fell to 0.04mmt from 0.15mmt, down 0.11mmt (-73 percent). Brazil, Jamaica, Japan, Pakistan and South Korea were not seen in the market in January, down from a total of 0.55mmt in December. We were still tracking a 0.08mmt cargo broadly headed for the Pacific and one 0.05mmt shipment destined for Europe at the time of writing.

Americas: Our US LNG export data showed shipments grew by 0.27mmt (3 percent) to 9.11mmt in January from 8.84mmt in December.

US LNG export plants showed mixed performance in January. Plaquemines LNG boosted exports to 0.47mmt from 0.08mmt, up 0.39mmt (488 percent), whilst Sabine Pass LNG flows grew to 3.08mmt from 2.80mmt, up 0.28mmt (10 percent). Concurrently, Cove Point LNG volumes rose to 0.69mmt from 0.51mmt, showing growth of 0.18mmt (35 percent). However, Calcasieu Pass LNG exports decreased slightly to 0.83mmt from 0.86mmt, down 0.03mmt (-3 percent), whilst Elba Island LNG fell to 0.16mmt from 0.22mmt, a reduction of 0.06mmt (-27 percent). Cameron LNG and Corpus Christi LNG saw volumes decrease to 1.37mmt and 1.30mmt from 1.45mmt and 1.42mmt respectively, down 0.08mmt (-6 percent) and 0.12mmt (-8 percent). Freeport LNG showed the largest decrease to 1.21mmt from 1.50mmt, down 0.29mmt (-19 percent). The plants operated at 25 percent, 121 percent, 155 percent, 86 percent, 75 percent, 108 percent, 102 percent and 92 percent of their annualised capacity utilisation respectively.

US LNG flows in January showed Northern European imports increasing to 3.25mmt from 3.07mmt, up 0.18mmt (6 percent), whilst Southern European volumes fell to 2.56mmt from 3.12mmt, down 0.56mmt (-18 percent). Eastern European imports grew to 0.61mmt from 0.31mmt, up 0.30mmt (97 percent). We were also still tracking 1.35mmt that still had to declare their destinations within Europe. Meanwhile, India saw a slight increase to 0.31mmt, up 0.02mmt (7 percent) whilst other Southeast Asian-directed volumes grew to 0.08mmt from 0.06mmt, up 0.02mmt (33 percent). Middle Eastern imports decreased to 0.22mmt from 0.37mmt, down 0.15mmt (-41 percent), and Far Eastern volumes fell to 0.15mmt from 1.01mmt, showing a reduction of 0.86mmt (-85 percent). However, we were still tracking 0.30mmt broadly headed for the Pacific at the time of writing. Concurrently, Central America and Caribbean imports decreased to 0.13mmt from 0.23mmt, down 0.10mmt (-43 percent). Exports to South America halved to 0.15mmt in January, with shipments to the Pacific and Atlantic sides split in a 0.08mmt and 0.07mmt cargo, respectively.

Atlantic LNG in Trinidad and Tobago decreased its production to 0.74mmt in January from 0.85mmt in December, thus showing a reduction of 0.11mmt (-13 percent). The plant's annualised capacity utilisation rate stood at 57 percent. Concurrently, NFE's Altamira Fast LNG project curtailed shipments by 0.04mmt (-40 percent) from 0.10mmt to 0.06mmt.

Middle East

Middle Eastern LNG exports in January amounted to 8.87mmt and thus constituted an increase of 0.77mmt (10 percent) from 8.10mmt in December. Our data thus showed the Basin's annualised utilisation of operational export capacity (i.e., excluding Yemen) at 112 percent. The Middle East's exports nevertheless did not grow year-on-year but remained broadly steady compared to 8.90mmt.

The Middle East's exports were led by flows from Qatar's Ras Laffan LNG complex. Our data showed the facility increased exports by 0.57mmt to 7.22mmt in January, representing growth by 9 percent from December, when it shipped 6.65mmt. The plant's annualised capacity utilisation rate thus stood at 110 percent.

The most significant contingent of Qatari LNG – shipments to the Far East – fell by 0.19mmt from 3.72mmt to 3.53mmt (-5 percent) in January. Concurrently, the Indian Subcontinent, Northern Europe and Southern Europe also saw smaller Qatari flows, decreasing to 1.16mmt (-4 percent), 0.38mmt (-14 percent) and 0.38mmt (-12 percent), respectively. However, the Middle East and Southeast Asia showed significant growth, with the Middle East rising to 0.85mmt (16 percent) and Southeast Asia reaching 0.30mmt (150 percent). Renewed demand for Qatari LNG also emerged from Eastern Europe with 0.10mmt. In addition, we were still tracking 0.35mmt headed for unidentified European destinations as well as 0.17mmt broadly headed for the Pacific.

Meanwhile, an export increase of 0.15mmt (16 percent) to 1.10mmt in Oman was compounded by an increase of 0.05mmt (10 percent) to 0.55mmt by the UAE's Das Island plant. This meant annualised capacity utilisation at Oman LNG stood at 125 percent whilst at Das Island LNG that figure stood at 118 percent.

Concurrently, Egypt had again not made an appearance in the market in January, according to our data at the time of writing. The country had last shipped a cargo in April last year.

Imports & Domestic Trade

Global LNG imports at the time of writing had remained broadly steady at 37.25mmt compared to the 37.29mmt we recorded this time in December. Demand growth was led by the Atlantic Basin, followed by a relatively modest volume increase in the Middle East. However, Pacific offtakes were down significantly.

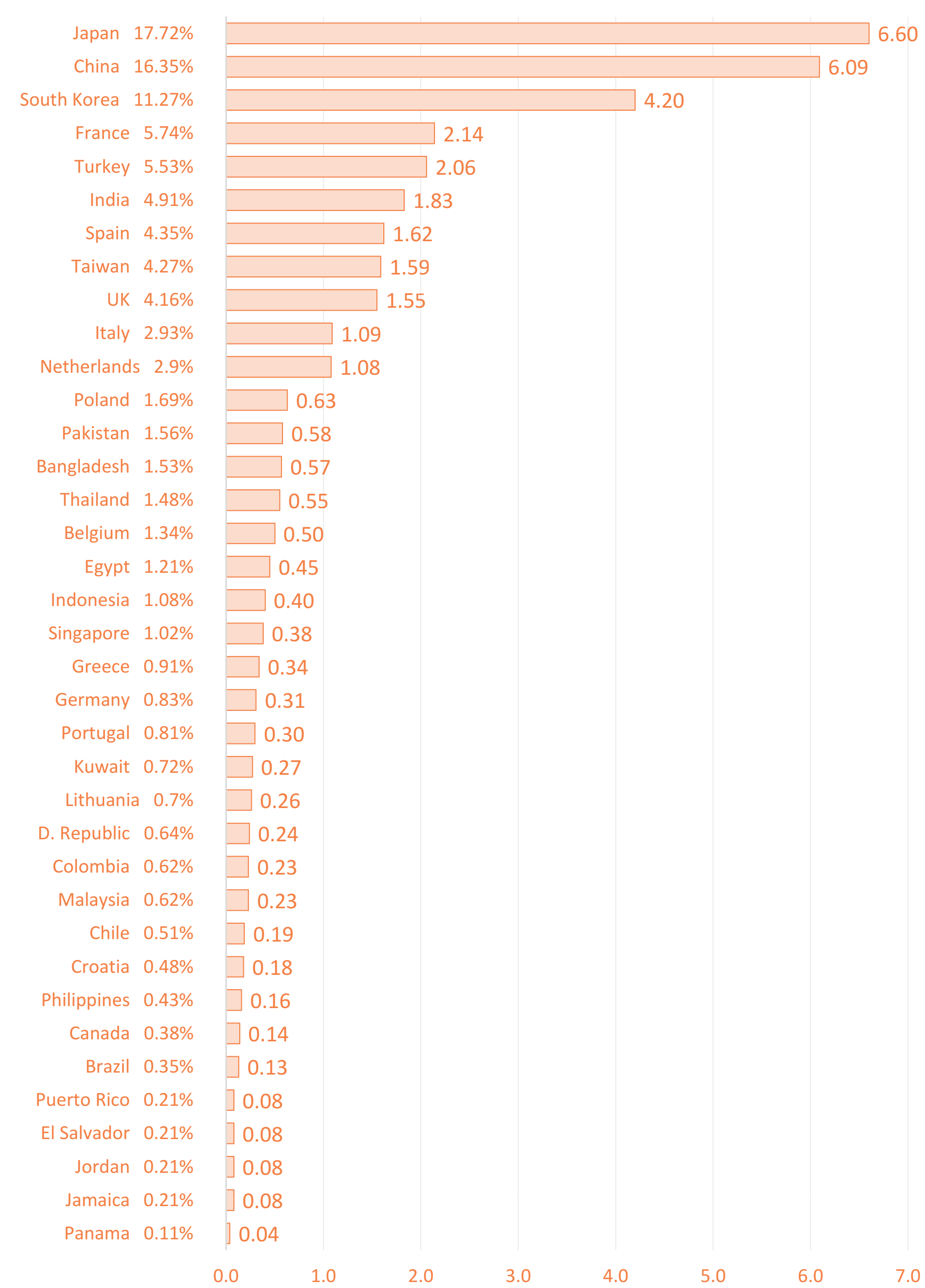
Pacific Basin

Period-on-period Pacific Basin imports were down by 1.02mmt (-4 percent) net to 22.87mmt from 23.89mmt in December. The roster of larger-scale importers comprising China, India, Taiwan, South Korea and Japan collectively curtailed their offtakes by 1.09mmt (-5 percent) to 20.31mmt from 21.40mmt in December.

Concurrently, the roster of smaller Pacific buyers collectively saw imports increase from 2.43mmt to 2.56mmt by 0.13mmt (5 percent). Malaysia showed the strongest growth, rising from 0.08mmt to 0.23mmt (188 percent), whilst Bangladesh volumes increased from 0.46mmt to 0.57mmt (24 percent). Moreover, the Philippines doubled its imports to 0.16mmt from 0.08mmt, whilst Chilean inflows rose from 0.13mmt to 0.19mmt (46 percent) and Indonesian imports grew from 0.36mmt to 0.40mmt (10 percent). El Salvador was also again

Market Share & LNG Imports by Country (MMt)

January 2025



Source: LNG Journal

seen in the market with 0.08mmt. However, Mexico did not make an appearance as an importer, down from 0.06mmt during the previous period. Additionally, Singapore reduced imports from 0.47mmt to 0.38mmt (-19 percent), whilst Thai demand fell from 0.79mmt to 0.55mmt (-30 percent).

Atlantic Basin

LNG demand in the Atlantic Basin increased by 0.89mmt (7 percent) to 13.00mmt, with annualised utilisation of installed capacity at 46 percent.

Overall, LNG imports across Europe reached 12.06mmt in January, up from 11.18mmt in December, marking an increase of 0.88mmt (8 percent).

European LNG imports showed substantial changes across different markets, with Spain leading the increases as volumes rose by 0.55mmt to 1.62mmt from 1.07mmt (51 percent). France followed with imports growing by 0.40mmt to 2.14mmt from 1.74mmt (23 percent), whilst Poland added 0.21mmt to reach 0.63mmt from 0.42mmt (50 percent). Lithuanian offtakes grew by 0.12mmt to 0.26mmt from 0.14mmt (86 percent), and the Netherlands showed modest growth of 0.09mmt to 1.08mmt from 0.99mmt (9 percent). Moreover, Belgium recorded a marginal increase of 0.05mmt to 0.50mmt from 0.45mmt (11 percent), whilst Croatia added 0.02mmt to reach 0.18mmt from 0.16mmt (13 percent). Greece showed a slight increase of 0.02mmt to 0.34mmt from 0.32mmt (6 percent), and Portugal's imports rose by 0.01mmt to 0.30mmt from 0.29mmt (3 percent).

In contrast, Germany recorded the largest decrease as volumes fell by 0.24mmt to 0.31mmt from 0.55mmt (-44 percent). Turkey, meanwhile, reduced imports by 0.16mmt to 2.06mmt from 2.22mmt (-7 percent). Moreover, Italy's imports fell by 0.08mmt to 1.09mmt from 1.17mmt (-7 percent) whilst the United Kingdom showed a slight decline of 0.01mmt to 1.55mmt from 1.56mmt (-1 percent). Notably, Finland and Malta were not seen in the market following imports of 0.06mmt and 0.04mmt, respectively, in December.

Imports across the Americas reached 0.94mmt in January, up from 0.87mmt in December, marking an increase of 0.07mmt (8 percent). Canadian imports led the change with 0.14mmt after showing no demand in December. In similar vein, Panama added 0.04mmt. Elsewhere, the Dominican Republic followed with an increase of 0.09mmt to 0.24mmt from 0.15mmt (60 percent) whilst Jamaica saw significant growth of 0.06mmt to 0.08mmt from 0.02mmt (300 percent). Puerto Rico also experienced notable demand growth, increasing offtakes by 0.02mmt to 0.08mmt from 0.06mmt (33 percent).

However, Colombia's volumes fell by 0.05mmt to 0.23mmt from 0.28mmt (-18 percent) whilst Brazil decreased imports by 0.08mmt to 0.13mmt from 0.21mmt (-38 percent). Both the United States and the OPT Hub on the US Virgin Islands were not seen in the market, thus effecting demand decreases of 0.06mmt and 0.09mmt, respectively.

Middle East

Overall, Middle Eastern LNG demand increased by 0.09mmt (7 percent) to 1.38mmt in January from 1.29mmt in December, with the region's annualised capacity utilisation at 26 percent.

Egypt and Kuwait saw moderate demand growth, with Egyptian offtakes increasing by 0.01mmt to 0.45mmt from 0.44mmt (2 percent), utilising 167 percent of its annualised capacity. Kuwaiti imports rose by 0.03mmt to 0.27mmt from 0.24mmt (13 percent), operating at 15 percent of its annualised capacity. Additionally, Jordan returned to the market with an import of 0.08mmt in January, representing annualised capacity utilisation of 26 percent. However, Pakistan moved in the opposite direction as volumes decreased by 0.03mmt to 0.58mmt from 0.61mmt (-5 percent), but with its facilities still running at 93 percent of annualised

Is a nuclear powered LNGC a possibility?

Towards the end of last year, ABS published a concept study on an LNGC design fitted with a nuclear propulsion plant. Technical Editor Ian Cochran investigates.

This study was compiled in co-operation with Herbert Engineering Corp, and revealed that advanced reactors were not designed for commercial marine use.

A standard LNGC deign was presented to illustrate how one type of advanced nuclear fission technology may be applied for shipboard power in the future.

The reactors used in this study were intended for land-based applications. The primary design assumptions were:

- The reactors' size is relatively fixed to enable them to be mass produced. For example, if a 30 MW reactor is chosen, only multiples of that size will be utilised, rather than attempting to scale the reactor up or down to a theoretical installed power level.
- The high-temperature gas cooled reactor (HTGR) chosen for this study is an advanced reactor with enhanced performance properties, including inherent safety and security features. Relatively high operational temperatures facilitate higher-efficiency energy conversion, while lower operating pressures allow smaller emergency planning zones (EPZ), compared to conventional land-based nuclear reactors.
- An increased level of redundancy, compared to what is normally seen in normal vessel design is assumed to be required for a nuclear-powered commercial vessel. This includes providing an alternative means of propulsion through redundant motors and power generation, as well as emergency power provided by diesel generators for safe return to port in the event a reactor failure.
- The reactors will be located aft of the accommodation block to shield the cryogenic cargo from the reactor compartment's thermal load. For collision protection, the reactor compartments will be installed above the B/15 bottom damage line and within the B/5 transverse damage penetration extents.
- It is also assumed that the nuclear reactors will be supplemented by battery power in an electric propulsion configuration for load-following and peak-shaving capabilities that will be more difficult to meet with nuclear reactors typically designed for constant power generation services.

Batteries will also provide continuous power to all vessel systems for a limited time in the case of main power plant failures before the emergency power diesel generators kick in.

The nuclear reactor technology for commercial marine applications is limited to small modular reactors (SMR) - designed to generate between 10 and 300 MWe, and micro-reactors - designed to generate up to 10 MWe.

Economies of scale

They are deemed to be factory built, according to a standard design to benefit from economies of scale and reduced licensing costs.

HTGRs, such as BWXT's advanced nuclear reactor (BANR), have lower thermal power ratings. They are characterised by inherent safety features, excellent fission product retention in the fuel and high-temperature operation, suitable for the delivery of industrial process heat.

Although they may have limitations for on board use, due to the high temperature (for instance, in the case of an LNGC, it is imperative that the reactor heat dispersed through ventilation is released away from the cryogenic cargo), they imply a smaller EPZ than some other advanced reactor designs.

However, the reprocessing or disposal arrangements of TRISO spent fuel are not fully developed and may need to be addressed to realise the benefits of the fuel.

HTGRs are modular, factory-fabricated systems that are small and light enough to be transported via rail, ship or truck. They are helium-cooled and uses HALEU

A nuclear powered LNGC

(19.75% enriched) uranium oxycarbide (UCO) TRISO fuel and graphite matrix as a moderator to produce 50 MW thermal (MWt) in the thermal neutron energy range. A nominal steam Rankine cycle of 35% efficiency is proposed to generate net 17.5 MWe.

However, a higher core outlet temperature may enable direct Brayton cycle or combined cycle to increase efficiency from 35% to greater than 50%.

Advanced sensors enable semi-autonomous control, and a five-year nominal lifetime before core skid replacement would allow refuelling at each ship's special drydocking.

Nuclear-powered commercial vessels' technical requirements differ from military nuclear vessels in the following ways:

1) Commercial vessels cannot have an extensive crew dedicated to managing the nuclear plant for administrative and cost concerns.
2) They cannot represent an increased threat to nuclear proliferation for security and safeguard concerns.
3) The ports visited cannot adopt special evacuation arrangements for public perception and safety concerns.
4) Commercial vessels need to be cost-competitive and should be designed with economy as a critical factor.
5) They need to maintain an acceptable level of safety even in all accident scenarios, including grounding and capsizing.

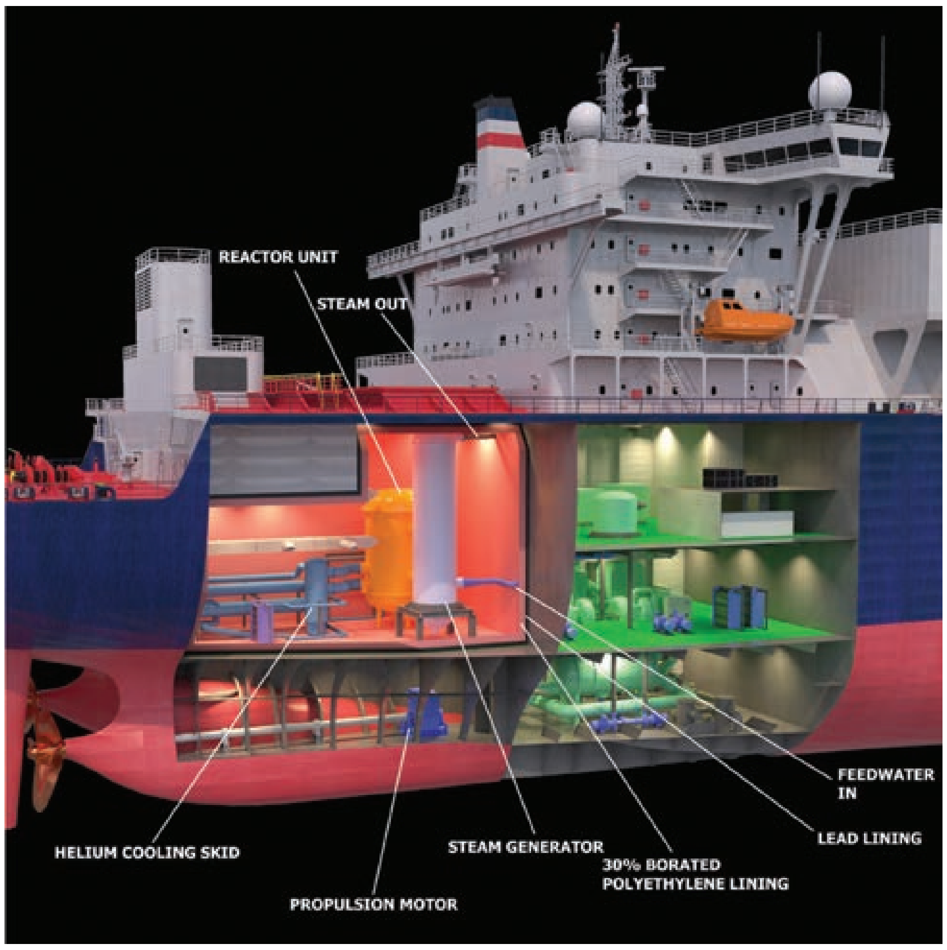
There are other technical requirements to be satisfied by the power plant, which may prove nuclear to be advantageous over other fuelled power arrangements:

a. The power plant (including all ancillaries and fuel) needs to be as compact and lightweight, as practicable for a given the range and power requirements.
b. The plant needs to be as easy to maintain as possible during short periods of drydocking.
c. It also needs to offer a range that allows the ship to operate along the proposed service route, ie, the design should minimise the need for refuelling.
d. It needs to be flexible enough to adapt to the variable vessel load profiles, with longer-term oscillations, such as those typical of time at sea, time in port and time in the yard, as well as transient power variations, such as those occurring during manoeuvring or cargo handling operations. This is known as load following capability.

Other design considerations stemming from basic naval architecture and nuclear technology requirements are summarised as follows:

1. A nuclear-electric plant is preferred over a direct drive take-off from the turbine for several reasons:
a. It allows the reactor location to be decoupled from that of the main propulsion, thus allowing reactor safety optimisation.
b. It is easier to interface with alternative emergency power production systems/equipment.
c. It is most flexible in terms of power management, particularly when associated with batteries.
d. It lends itself to being redundant.
2. The location of the nuclear reactor is affected by the following:
a. Radiation shielding characteristics, with particular emphasis on weight and

145k m3 LNG carrier, HTGR ship profile



Machinery space rendering

volume in relation to the ship's trim, stability and structural strength.

b. Structural or mechanical protection from collision, grounding and malicious attacks.

c. Security arrangements for the protection from unauthorised access.

d. Ship accelerations and vibration experienced under all operating profiles.

e. Considerations of auxiliary power-generating machinery and explosion hazards.

f. Consideration of the cargo areas and loading/unloading operations.

g. Consideration of reactor maintenance and ease of installation/removal.

3. If the nuclear plant's load-following is supplemented by the inclusion of batteries for peak shaving, their location needs to account for fire and explosion risk, hazardous area requirements, monitoring, access, weight and replacement concerns.

4. The choice of the turbo-machinery and electrical generation plant is mostly a result of the reactor's functional characteristics and operating temperatures, as the two need to be designed together.

At this stage, nuclear waste generation, handling, storage and discharge arrangements cannot be addressed in detail.

Power requirements

The HTGR's electrical power capacity reasonably matches the overall installed power requirements of a standard 145,000 cu m membrane LNGC.

For this type of vessel, the total installed power requirement is estimated to be about 35,000 kW; 11,650 kW of which would cover the hotel load and associated redundancies, while the remaining 23,350 kW will be needed to achieve the design speed of 19.5 knots.

This power requirement can be satisfied by two standard nuclear power plants using two steam turbines per reactor, each with an assumed 35% power conversion efficiency.

Assuming this limit is 60% of maximum power output, having two reactors and four turbines allows the plant's output power range to go from a minimum of 5,250 kWe to the full 35,000 kWe.

This also provides some redundancy and improved resilience to turbine breakdowns, albeit at the cost of increased capital expenditure (CAPEX) and plant complexity.

When a lower level of power is needed, this would be attained by shutting two or three of the four turbines and recharging the ancillary battery set. Alternatively, the vessel could reverse-cold iron (providing power to the shoreside grid) if relevant facilities were available at the port.

Excess reactor heat would be ejected through reactor cooling vent stacks. The original land-based designs envisioned these reactors as air-cooled, so substantial fan rooms, air supply ducting and exhaust piping have to be fitted on deck above the reactors and extend above the hazardous area zone to provide the necessary airflow.

This excess heat venting would need to handle the entire maximum reactor load. However, the heat supplied to the Rankine steam cycle would be partly utilised by the turbo generators, and partly ejected through standard, seawater-cooled steam condensers.

The steam condensers and associated circulating pumps size is likely to require around the lower one-third of the power generation rooms. It is conceivable that some of this heat might be reclaimed to reduce the overall hotel electrical load requirement.

Power reduction

It also should be noted that, in an emergency, the reactors can be brought to a reduced power state or shut down, where the thermal energy produced is substantially reduced.

In this event, ancillary batteries and emergency diesel generators would power the ventilation system.

An LNGCs cryogenic insulated cargo tanks mean that the vessel is sensitive to heat sources close to the cargo block area. For this reason, the reactor rooms are placed aft of the accommodation block and the power generation rooms.

Reactor compartment ventilation stacks could then be placed far aft and well away from the cargo block.

Each reactor compartment is 23 m long, 15 m wide and 15 m high. All boundary surfaces are covered with 120 mm thick 30% borated polyethylene for neutron shielding and 60 mm thick lead for gamma ray shielding.

This primary shielding adds about 300 tonnes to the reactor weight but helps reduce the neutron and gamma ray shielding materials for the enclosing bulkheads and decks.

This results in a total weight of shielding equal to 2,900 tonnes, which is additional to the 2,300 tonnes of the reactors and associated power plants.

The power generation compartments are more extensive, each being around 22 m long, 22 m wide and 26 m high.

Similar to the reactor rooms, two power generation compartments are provided and separated by a longitudinal bulkhead at CL, providing improved redundancy (and therefore enhanced safety and reliability) in case of flooding or fire in one of the two compartments.

Electric motors drive the LNGC's main propulsion units. At the ship's stern is a standard twin-screw, twin-rudder 'gondola' design, which provides sufficient room for two 11,675 kW motors near the propellers under the reactor room.

The bulkheads and decks separating the steering gear room, motor room and power generation room from the reactor room, are all lined with 500 mm thermal insulation.

This location allows the deck immediately above the reactors to be free from equipment, facilitating the extraction of the core every five years during special drydocking for refuelling.

Furthermore, this configuration works reasonably well in terms of weight management. This means that the design's cargo block configuration would remain identical to that of the conventional ship equivalent, implying no cargo capacity loss.

A re-liquefaction plant was not considered in this study, as these systems would likely imply an increase in power demand, which would be harder to meet with the chosen HTGR design.

Although the HTGR is capable of load-following at a rate of change of a few percentage points per minute, this may not be sufficient to deal with the rapid load changes typical of ship manoeuvring and so, a small ancillary battery set of around 54 MWh capacity will be placed at the bow.

These batteries cannot be used as an alternative power source for a safe return to port since the total endurance at full power would be less than two hours.

Drawbacks

However, ABS found that this design configuration had two main drawbacks -

First, since the weight of reactors, shielding and power generation equipment exceeds that of the engines, machinery, main fossil fuel tanks and funnel stack of a conventional LNGC by about 700 tonnes, the balance of trim needs to be at least partly restored by placing the ancillary battery sets (weighing around 270 tonnes) at the bow, where the remaining fossil fuel of a conventional LNGC would typically be stored.

This implies a modest increase in the ballast ship hogging/bending moment that would require a slightly more robust hull structure.

Second, the reactor location aft implies higher ship motion accelerations than those experienced at or near the midship section (MS). For this reason, the local accelerations were estimated using the IGC Code Regulation 4.28.2 "Guidance formulae for acceleration components."

Finally, the HTGR needs to be refuelled every five years. This implies opening the reactor room and removing the reactors, and this can only happen in shipyards or other facilities, which are equipped to deal with radioactive material.

The HTGR's maintenance and refuelling would need to be achieved within the normal special survey drydocking times. ■

US regulatory shift to accelerate LNG bunkering hub development

Plans to dramatically increase US exports may provide a boost for LNG fuelling hubs in the country as the industry prepares to ramp up investment. Fuelling Editor Malcolm Ramsay has more.

The US economy could be boosted by as much as US$1.3 trillion, following Trump's reversal of the Biden moratorium LNG exports. While the majority of investment will be focused on new pipelines and export facilities, the boom in LNG infrastructure is also expected to spur a new wave of bunkering hubs.

Declaring that the "war on fossil fuels exports is over", Louis E. Sola Commissioner of the Federal Maritime Commission, highlighted "the importance of ending the pause on LNG infrastructure project approvals".

Port of Salina Cruz

GLBP permits secured

A key example of this acceleration under the new administration has been the rapid approval of environmental permits for the Galveston LNG bunkering port (GLBP) in January.

First announced in 2023, the GLBP is under development as a joint venture between fuelling specialist Pilot LNG and Seapath Group, a subsidiary of asset manager Libra. The proposed facility will have capacity to supply up to 600,000 gallons per day of LNG.

"The support from our board, the team at Libra, and our partners Pilot LNG has us on target to shake up the US LNG bunkering scene," Joshua Lubarsky, president of Seapath Group, comments "This facility is a critical investment into the resilience of the United States' maritime infrastructure, and upon construction will immediately provide positive environmental and economic impacts in Texas City, Galveston Bay and the US Gulf Coast."

Critical infrastructure

Last year, GLBP signed an agreement with Houston Pipeline Co (HPL) for long-term gas supply to the bunker hub, which will cover an area of 140 acres of land at Shoal Point at the head of Galveston Bay.

"This year, we continue our commitment to advancing critical infrastructure projects that will ensure a reliable supply of clean-burning LNG for the rapidly growing fleet of LNG dual-fuelled vessels," Jonathan Cook, CEO of Pilot LNG said, noting that securing gas supply was "essential to the successful delivery of LNG as a fuel in Galveston Bay".

As part of the construction process two giant storage tanks will be installed on site, each with capacity of 3 million gallons.

Artist's rendition of Galveston LNG Bunkering Port

With environmental permits in place, construction of the bunker hub is now one step closer to completion, with operations scheduled to begin in mid-2026.

The new facility is expected to draw investment of US$150 million, and once complete will provide fuel for LNG-powered vessels across the bay region, including the ports of Houston, Galveston and Texas City, as well as Galveston Offshore Lightering Areas.

Regional impacts

Increased investment appetite for LNG infrastructure development on the US Gulf Coast is also now driving interest in projects across the wider region. At the end of last year, Pilot LNG announced plans for another LNG bunkering project, this time in Mexico.

In partnership with diversified energy solutions company GFI LNG (GFI), the firm will develop, construct and operate an LNG bunkering and transshipment terminal in Salina Cruz, on the west coast of Mexico.

"The infrastructure planned in Salina Cruz will not only provide LNG to growing markets seeking cleaner fuel but will also bring millions in direct community investment to the region" Maria Gomez, founder of GFI said. "We are pleased to be adding the LNG and marine expertise of Pilot to the development team. Thanks to our new partnership with Pilot, we look forward to bringing this facility to Salina Cruz."

Similar in size to the Galveston hub, the Salina Cruz facility will produce 600,000 gallons of LNG per day. The project is designed to include modular, land-based liquefaction equipment and an optimized storage solution, with operations scheduled to commence in mid-to-late 2027.

The LNG hub will be supplied by domestic Mexican gas from the Veracruz gulf region and will provide LNG bunkering for high-value markets along the Pacific Coast, including LNG marine fuel deliveries at the Pacific entry of the Panama Canal and into the Ports of Long Beach and Los Angeles in Southern California. The partners also plan to target sales into Central American power markets, and trucked volumes in the local region of southwestern Mexico.

"The project will deploy a floating storage unit with an estimated capacity ranging from 50,000 – 140,000 m3 to be moored inside the newly expanded breakwater in the Port of Salina Cruz," a spokesperson for Pilot LNG said.

Front-end engineering and design development for the project is due to start this quarter and the partners expect a Final Investment Decision (FID) in the second half of 2025. Development and permitting is forecast to take around 12 to 28 months in total. ■

For the Record

ADNOC: Japan's major energy buyer, JERA Global Markets and the UAE's main energy supplier, ADNOC Gas have signed a $450 mill (AED1.653 bill) LNG supply agreement.

Under the terms of the agreement, LNG will be supplied by ADNOC Gas to JERA Global Markets' global supply portfolio for three years.

This agreement reinforces both companies' long-standing relationship established in 1977 and further builds on the supply agreement signed between JERA Global Markets and ADNOC Gas in 2023, they said.

LNG will be supplied from ADNOC Gas' Das Island liquefaction facility, which has a production capacity of around 6 mill tonnes per annum.

"As a utility-backed trader, JERA Global Markets' purpose is to provide energy security to the communities that we serve.

"This supply agreement with our long-standing partner ADNOC reflects the active measures we take to ensure that our global portfolio remains diverse, flexible and competitive," explained Kazunori Kasai, Chief Optimisation Officer, JERA Co and Chairman, JERA Global Markets.

Fatema Al Nuaimi, ADNOC Gas CEO, added: "This agreement builds on decades of collaboration between ADNOC and JERA, solidifying our shared commitment to ensuring energy security and supporting the global transition to a lower-carbon future.

"By continuing to serve Japan's growing energy needs, ADNOC Gas demonstrates its position as a reliable partner in the global LNG market," she said.

ASIA: Asian spot LNG) prices saw little change last week (starting 20th January), as ample inventories and mild weather capped demand from East Asian buyers.

The average LNG price for March delivery into north-east Asia rose slightly to $14 per MMBtu, industry sources estimated.

"Demand in Asia remains tepid, with East Asia demand relatively constrained amidst warmer than usual weather," said Pang Lu Ming, Rystad Energy senior analyst, talking with S&P Global, adding that local forecasts indicated that South Korea and Japan would see above-normal temperatures through to early and mid-February.

While southern China will also experience warmer than normal temperatures in coming days, colder temperatures will be seen in parts of the north, Pang said.

East Asian inventories were quoted as ample.

"Activity from Japanese players remains subdued, implying sufficient winter inventories for existing forecasts," Pang added, saying South Korean and Chinese players also continued to report sufficient inventories for winter.

In Europe, S&P Global Commodity Insights assessed its daily North West Europe LNG Marker (NWM) price benchmark for cargoes delivered in March on an ex-ship (DES) basis at $14.589 per MMBtu on 23rd January, a $0.37 per MMBtu discount to the March gas price at the Dutch TTF hub.

Natasha Fielding, head of European gas, LNG and biomass pricing at Argus, noted European delivered LNG prices had increased their premium over northeast Asian markets, pointing to storm disruption to US loadings and higher summer restocking demands, following a German proposal to subsidise summer injections.

Freeport LNG also closed its export plant in Texas last Tuesday, due to a power feed problem during a winter storm.

The European premium has further persuaded companies to ship uncommitted LNG cargoes in the Atlantic basin to Europe instead of Asia, and they could also start to pull Middle Eastern supply away from Asia, Fielding added.

LNG freight rates fell to record lows, with Atlantic rates dropping for a third straight week to $9,000 per day on Friday driven by an influx of newbuildings and the directing of US spot cargoes to Europe, said Spark Commodities analyst, Qasim Afghan.

Pacific rates fell to $15,500 per day.

The US arbitrage to northeast Asia via the Cape of Good Hope for February widened, again indicating that US cargoes have an incentive to deliver to Europe, Afghan added.

He also said that the Qatar front month arbitrage to Northeast Asia had closed out for the first time in almost two years, also incentivising deliveries to Europe over Asia.

BAKER HUGHES: US engineering company, Baker Hughes has been awarded a major contract to provide a modularised LNG system and power island to support Venture Global LNG projects.

In addition, the company signed a multi-year services frame agreement, including maintenance, inspection, repairs and engineering services, to support phases 1 and 2 of Venture Global's Plaquemines LNG project in Louisiana.

"As power demand surges, LNG has a critical role to play in providing a reliable, flexible fuel source that can be quickly scaled to meet rising demand," said Lorenzo Simonelli, Baker Hughes' Chairman and CEO.

"We have been a trusted partner in natural gas operations for more than 30 years, and our collaboration with Venture Global is a key example of what our industry needs more of today: businesses coming together to leverage best-in-class technologies and services that can deliver reliable and efficient natural gas operations to support sustainable energy development," he said.

"Baker Hughes continues to be a trusted partner for Venture Global in delivering a secure, reliable energy supply to the world and we are thrilled to add another significant milestone on our partnership," added Mike Sabel, Venture Global CEO.

Baker Hughes, as an LNG technology supplier to Venture Global for more than 100 mill tonnes per annum of production capacity, has already provided comprehensive LNG solutions to the Calcasieu Pass and Plaquemines LNG facilities.

Recently, Venture Global announced the successful loading and departure of its first LNG cargo produced from the Plaquemines LNG facility, after reaching first LNG production.

BANGLADESH: Bangladesh has signed a non-binding agreement with a US plant developer, Argent LNG, to purchase up to 5 mill tonnes of LNG per annum.

Argent LNG is developing a 25 mill tonnes per annum LNG export facility at Port Fourchon, Louisiana.

This is the first major US LNG supply deal reported since US President Donald Trump took office last week, according to Argent LNG.

Since becoming President, Trump has taken action to end the US Department of Energy's (DoE) pause on licenses to export LNG to countries that do not have free-trade agreements with the US, in an attempt to increase US LNG exports.

If the Argent LNG project in Port Fourchon gets the go ahead, the cargoes will be destined for Bangladesh's state owned energy company, Petrobangla, according to the agreement.

Ashik Chowdhury, Bangladesh Investment Development Authority Chairman, said: "This agreement not only ensures a reliable energy supply for Bangladesh's expanding industrial base but also strengthens our strategic partnership with the US."

Bangladesh is highly price-sensitive and in 2022, as LNG prices surged following Russia's invasion of Ukraine, the country moved back to using more affordable coal.

DEUTSCHE REGAS: Privately owned German LNG terminal operator, Deutsche ReGas has claimed that the potentially lower prices offered by state-owned Deutsche Energy Terminal (DET) to attract buyers are a threat to its business.

Germany's aim to increase its regasification capacity intensified as it sought to replace Russian pipeline gas, the country's former main supplier.

As a result, FSRUs were installed at various ports in record time.

But with European underground gas caverns well filled, and with LNG terminal overcapacity, it is getting tougher to attract cargoes to the new infrastructure, Deutsche ReGas said.

"Since Christmas 2024, we have been facing unequal competition with DET," the company's CEO Ingo Wagner told reporters, adding that state rules say that DET must not offer slots at prices below costs.

ReGas claimed that state-subsidised DET can afford to go below the price that would be considered the minimal level to recover costs.

As a private company, he said that ReGas cannot match these levels.

ReGas's Deutsche Ostsee terminal is located in the Baltic Sea at Mukran and is crucial for shipping gas to countries, such as the Czech Republic and Slovakia in the future, which are reversing pipeline directions after Russian supplies dried up.

The pipeline transit deal between Russia and Ukraine ended on 1st January and US President Donald Trump is targeting Europe to export more LNG.

DET is due to hold short-term auctions for regasification capacity at Wilhelmshaven and Brunsbuettel in the North Sea next week.

Its operations were approved under European Commission state aid rules last December.

Germany built Wilhelmshaven, Brunsbuettel and Lubmin, near Mukran and its forerunner, from the winter of 2022 onwards and chartered ships as part of its emergency response to the reduction of Russian gas after the war in Ukraine.

DET had told Reuters that short-term auctions in December helped ensure supply security at all times, amid muted booking interest.

"We are complying with the regulatory requirements for the marketing of regas capacity for our terminals," a DET spokesperson said.

The auctions are for LNG discharge, regasification, send-out and storage.

EUROPEAN UNION: Europe has not proposed a ban on Russian LNG during its latest package of sanctions.

This was because EU member states raised concerns about first securing alternatives, including from the US, officials have explained.

"First you have to have a deal because otherwise you will be left without gas from Russia and without the US," one of the diplomats said to newswires.

In June last year, the EU banned transhipments of Russian LNG in a further package of restrictions on Russia imposed over its 2022 invasion of Ukraine.

Russia had been using northern European ports to undertake LNG ship-to-ship (STS) transfers for onward journeys to Asia.

Since the ban took effect, more Russian LNG has remained in Europe, prompting some member states to push for tighter rules and an all-out ban.

However, the EC did not propose tougher measures after a push back from some member states. EU sources said the cold winter weather, gas stocks drawdown and the timing of the 23rd February German election put a further dampener on the idea.

"There was never an original measure, so I don't think it's useful to talk about it in terms of watering down," one European diplomat told Reuters.

"The general idea was floated by the Commission in confessionals in order to test the waters...Apparently, one or more members signalled enough opposition for the Commission not to deem it opportune to propose such a measure now."

US President Donald Trump has said he wants the EU to buy more US LNG and that he will make more of it available.

It is unclear when the EU could secure more US LNG in the short term, as exports are already at full capacity.

GOLAR: Golar LNG has signed an agreement to sell all of its shares in Avenir LNG to Stolt-Nielsen Gas for about $40 mill.

This transaction is expected to be completed during the first quarter of 2025, subject to the fulfillment of the conditions under the share purchase agreement, Golar said.

Golar will remain as a 25% shareholder and debt provider to Higas Srl, the HIGAS LNG storage terminal in Sardinia, that was spun off from Avenir LNG in October, 2024.

As of the end October, 2024, the book value of HIGAS was $40.5 mill (on a 100% basis), of which $24.7 mill was shareholder loans and $15.8 mill shareholders equity.

Golar CEO, Karl-Fredrik Staubo, commented: "The sale of Golar's shareholding in Avenir LNG is in line with our strategy to focus on expanding our market leading FLNG position.

"Golar is proud to have founded Avenir LNG into one of the largest small-scale LNG shipping companies globally alongside our partners Stolt Nielsen and Höegh.

"Following the sale of Hygo Energy Transition in 2021, our Avenir LNG investment was no longer deemed a core asset of Golar's portfolio. We wish the

Avenir LNG team and Stolt-Nielsen all the best for the future development of Avenir," he said.

INDIA: Planned US LNG production increases under the new Trump administration should benefit consumers, such as India, Petronet LNG's CEO Akshay Kumar Singh, said in an earnings call yesterday.

"If more LNG plants come in the US, it will stabilise international LNG prices.

"For a consuming nation like India, it is expected that if prices are in the range of $7-8 per MMBtu, the consumption will drastically improve because there is no shortage of customers - they are just price sensitive," he said.

Singh also said that he expected prices to be between $12-14 per MMBtu this quarter backed by strong European demand to refill stocks. The additional volumes required could keep prices elevated during the second quarter of this year.

He revealed that Petronet was working to ship LNG to Sri Lanka, following the signing of a contract to supply LTL Holdings' Colombo power plants for five years.

LNG would be shipped from the Kochi terminal to Colombo.

Petronet reported its highest gross profit (PBT) and net profit (PAT) of Rs3,829 Crore and Rs2,856 Crore, respectively, in the nine months ending on 31st December, 2024.

The company also recorded the highest volume throughput of 686 TBTU at Dahej terminal during the period, a rise of 6% together with the most overall volume throughput of 729 TBTU.

During the quarter ended 31st December, 2024, Dahej processed 213 TBTU of LNG as against 218 TBTU during the corresponding period of 2023 and 225 TBTU during the previous quarter ending 30th September, 2024.

Petronet reported a PBT of Rs1,169 Crore for the last quarter, as against Rs1,597 Crore in the corresponding previous year's quarter and Rs1,140 Crore, in the third quarter of last year.

PAT was Rs867 Crore, as against the corresponding and previous quarters of Rs1,191 Crore and Rs848 Crore, respectively.

The robust financial performance of the last quarter and nine months of 2024 was achieved, due to efficiency in operations and higher capacity utilisation of the Dahej terminal, the company explained.

ITALY: Italy's incentive programme for gas and LNG operators is out of step with market reality, as it champions investing in infrastructure projects that will be underutilised.

New Institute for Energy Economics and Financial Analysis (IEEFA) research urged better alignment of government and regulatory support with market needs.

The existing regulatory programme may encourage excessive capital expenditure on redundant gas and LNG infrastructure, despite Italy's recent declining demand for both fuels.

Italy's gas demand dropped 19% from 2021 to 2024, while LNG imports fell 12% last year.

However, the country is on track to overbuild its regasification capacity, which is set to triple between 2022 and 2026.

As demand continues to decline, Italy's LNG consumption could be less than one-third of its import capacity by 2030, IEEFA said.

Italian energy company, Snam is the main beneficiary of this incentive scheme. The company's regulated revenues increased by €272 mill (20.1% year-on-year) in the first half of 2024.

Of this, the vast majority (€160 mill) was from a higher weighted average cost of capital and regulated asset base growth in its gas transportation and storage segments.

In 2023, Snam's regulatory revenues increased by €385 mill.

"Incentives to invest in infrastructure must be driven by demand. In the case of Italy, it's currently the other way around, with regulated revenues driving infrastructure build out even if there is not enough demand to justify it," said Ana Maria Jaller-Makarewicz, IEEFA's Lead Energy Analyst, Europe.

"Time's up for Italy to acknowledge its declining gas demand and that of its European neighbours. The country's ambition to become a gas hub risks jeopardising the competitiveness of its energy sector by mis-allocating government support to gas projects that don't offer long-term energy security solutions," she said.

"Snam's over-investment trend, shown in this straightforward work by IEEFA, is worrying. Any consistent de-carbonisation commitment requires dropping investments in gas infrastructure.

"To reduce the risk of stranded assets, investors and authorities should plan for an accelerated depreciation of existing gas infrastructure," added Michele Governatori, Head of External Relations, Energy, at ECCO.

Snam owns 61% of Italy's operational LNG terminals and 100% of two planned new terminals. The company supplies 95% of the Italian gas market and is the largest owner of gas pipelines in the European Union, with a combined length of nearly 38,000 km.

In 2021, Italy's regulator ARERA launched its Regulation by Objectives of Expenditure and Service (ROSS) programme to encourage accountability, support the energy transition and enhance performance-based incentives.

Despite this, Snam's investments and regulatory revenues from expanding its gas operations have continued to grow.

At the same time, the tariffs that Italian domestic customers pay for natural gas remain among the highest in the EU, IEEFA said.

JAPAN: Japan continued to hold the top LNGC ownership spot in terms of fleet value, according to VesselsValue.

As of this month, the Japanese LNG fleet is valued at $40.9 bill, up from $37.8 bill in February, 2024.

Japan also leads in LPG carrier ownership value and fleet size ($15.1 bill), reefers ($1.3 bill), and vehicle carriers ($24.8 bill).

Greece, which led the LNGC fleet value chart in 2021, is now in second position with a 143 vessel fleet worth $32.4 bill.

VesselsValue said that the Greek LNGC fleet's value had increased by just over $1 bill in the past year.

However, China has overtaken Japan for the most valuable overall fleet, reaching $255 bill. This was attributed to China's leading positions in bulker and container fleet values, at $68.4 bill and $63.5 bill. respectively.

LNG IMPORTS: The world's LNG imports are set to jump to the highest in a year last month, as Europe's winter demand draws cargoes away from Asia.

A total of 38.12 mill tonnes of LNG is on track to be imported in January, up from 37.69 mill in December and the most since January, 2024's 38.73 mill, according to data compiled by commodity analysts, Kpler.

According to Kpler, Europe's imports are expected to rise to 11.82 mill tonnes this month, up from 10.87 mill in December and the highest since April, 2023.

While Europe's LNG imports are likely to rise 8.7% in January from the month before, arrivals from Russia are expected to drop to 1.60 mill tonnes, down 11.6% from December's 1.81 mill tonnes.

Europe's Russian LNG imports are increasingly uncertain, especially with the return of Donald Trump as US President.

Trump is strongly in favour of boosting US energy exports, and LNG shipments to Europe offer one of the best opportunities to do so, sources said.

If European countries agree to phase out imports from Russia in favour of US cargoes, this move would help meet several objectives.

These include putting further pressure on Russian President, Vladimir Putin, to end the war in Ukraine, as well as giving Trump a 'win' that may help ease the threat of new tariffs on Europe's exports to the US.

However, the global LNG market may move into surplus by the end of this year, making it in the interests of both Trump and US LNG exporters to try and limit Russian export markets.

Europe's US LNG imports are expected to rise to a record high of 6.70 mill tonnes in January, up from 5.20 mill in December and 11.7% above the previous peak of 6 mill tonnes in January last year.

In contrast, Asia's imports of US LNG are expected to drop to 1.81 mill tonnes this month, down from 2.2 mill in December and the lowest since February, 2024, according to Kpler.

Asia's total LNG imports are also set for a decline in January, dropping to 24.48 mill tonnes from a 10-month high of 25.50 mill in December.

This decline is largely down to a milder-than-usual winter, which has trimmed demand in China, Japan and South Korea, the world's top three importers.

Relatively high spot prices have also cut demand, especially in China, with January arrivals are forecast to be 6.29 mill tonnes, down from December's 7.58 mill and almost 20% below the 7.83 mill seen in January, 2024.

The spot price for LNG for delivery to North Asia ended last week at $14 per MMBtu, up slightly from the $13.90 in the previous week.

European natural gas prices have also remained high, with the TTF benchmark ending at €47.90 per MWh, which is equivalent to $14.73 MMBtu.

MIDDLE EAST: Five Middle East countries, representing 85% of the region's gas output, were expected to add more than 20 bill cu m of production between 2023 and 2025.

This was a 3.3% increase over the two-year period, according to an IEA report.

Iran's gas production growth was estimated at less than 2% in 2024 and just over 1% in 2025, driven by a series of gas capture projects aimed at reducing flaring and incremental production increases at South Pars Phase 11.

Qatar saw a 2% production decline in 2024, due to shrinking domestic consumption amid the country's rapid solar PV rollout.

Given the lower domestic demand and strong export prospects, Qatar is undertaking a gas diversion project to direct feedgas flows to the country's LNG export facilities from the Barzan processing plant, which started operations in 2020 and was initially dedicated solely to the domestic market.

Gas production in 2025 is expected to remain broadly flat, as Qatar's next major expansion project - North Field East - is not expected to start up before 2026.

Saudi Arabia's gas production increased by an estimated 2% in 2024, thanks largely to the full-year impact of production from the Hawiyah gas plant expansion project and the first phase of the South Ghawar unconventional development, both of which came online in late 2023.

Saudi gas production is projected to grow by 4% in 2025, driven by the planned start-up of the Jafurah Phase 1 (2 bill cu m per year) and Tanajib (27 bill cu m per year) projects during the year.

Elsewhere, Oman increased its natural gas output by more than 4% in 2024, and it is projected to register further growth of 3% this year, as production from Block 10 continues to ramp up and the ongoing debottlenecking of the domestic gas grid enables higher production from existing fields.

The role of natural gas in the Middle East power sector has been increasing in the past decade and oil-to-gas switching continued in 2024, driven by Iran, Iraq, Kuwait and Saudi Arabia.

In road transport, the rapid scale-up of LNG trucks in China - with record sales in 2024 - is contributing to China's lower diesel demand.

The use of LNG as a bunkering fuel is also expected to increase amid increasingly stringent emissions regulations.

Based on the current orderbook, the number of LNG-fuelled ships is expected to almost double and reach over 1,200 vessels by 2028 (excluding LNGCs).

The displacement of oil and oil products in the power sector and long-haul transport is expected to continue over the medium term.

This article first appeared in IranOilGas.com

NAKILAT: Qatar Gas Transport Co (Nakilat) has announced a net profit of QAR1.64 bill for 2024.

This was an increase of 5.1%, compared to QAR1.56 bill for the 12 months of 2023.

As a result, Nakilat's Board has recommend the distribution of cash dividends of 7 Qatari Dirhams per share for the second half of last year.

This was in addition to the half yearly interim cash dividend of 7 Qatari Dirhams per share, which was distributed for the first six months ended 30th June, 2024, giving a total of 14 Qatari Dirhams per share for the whole year.

This stable growth underscores Nakilat's operational efficiency, its ability to seize emerging opportunities, which has been evident in the company's 2024 newbuilding announcements. and its resilience in navigating the challenges of the global energy transportation market, the company claimed.

The company added that last year was a transformative one, defined by a strategic vision and operational resilience. Through innovative practices and a focus on excellence, the company has successfully managed the challenges of the global shipping environment, driving sustained growth.

Looking ahead, Nakilat said that it was committed to leveraging its strengths and partnerships to build on the year's successes and contribute meaningfully to the global energy transportation landscape.

Nakilat's commitment to meeting the growing demand for clean energy transport continued to take shape last year, as the company increased its shipbuilding programme with Hyundai Samho Heavy Industries, which includes six advanced gas carriers under construction.

This programme comprises two 174,000 cu m LNGCs, and four modern LPG/Ammonia carriers, each with a capacity of 88,000 cu m.

The fleet expansion strategy is also strengthened by new long-term contracts with QatarEnergy for operating and chartering the nine 271,000 cu m QC-Max LNGCs , and 25 conventional 174,000 cu m LNGCs.

Upon their completion, Nakilat's fleet will expand to 114 ships.

Eng Abdullah Al-Sulaiti, Nakilat CEO, commented: "Nakilat's strategic fleet expansion, supported by its focus on achieving the highest standards of occupational health and safety, sustainability and innovation across all aspects of safe and reliable operations to meet the increasing global demand for clean energy transportation.

"As the company looks to the future, it remains committed to delivering value to its shareholders and partners ensuring long-term growth and success. Our financial and operational achievements in 2024 reflect the commitment and dedication of our team in delivering clean energy to the world safely and efficiently.

"These accomplishments are a testament to Nakilat's robust business strategy, its focus on customer-centricity, and its alignment with Qatar National Vision 2030," he said.

PETRONAS: Malaysia's energy giant, Petronas has confirmed that its operations in Bintulu and Miri were unaffected by the severe flooding, which occurred on 29th January.

"Petronas wishes to inform that its operations in Miri and Bintulu remain uninterrupted following the severe flooding in both areas on 29th January.

"The safety of our staff, their families, and the surrounding community is our top priority," Petronas said in a statement.

Petronas also said that the company was working closely with the relevant authorities to ensure the well-being of the people, environment, and assets.

"We would like to thank all parties, including the authorities and Bintulu Port, for their co-operation.

"We will continue to monitor the situation closely and provide support where needed," Petronas said.

RED SEA: Although the ceasefire agreement between Israel and Hamas seemed to bring some respite to regional tensions, the complete functioning of the Suez Canal will be a mixed bag for LNG shipping, Drewry Shipping Consultants said in a report.

While the resumption of Suez Canal transits could aid the role of Qatari LNG exports to Europe, cargoes from the US to Asia will likely continue transiting South Africa, conforming with shipping economics.

Meanwhile, the risk associated with the Red Sea transit remained high, with insurers keeping a cautious outlook for risk premiums.

Drewry expected no immediate return of LNGCs to the Red Sea in the near term, as the vessels were likely to continue transiting via the Cape of Good Hope, as risks of Red Sea transits remained high.

US shipments to Asia will continue taking the southern route in order to support shipping economics amid low freight rates and ample vessel supply.

Elsewhere, Qatari LNG exports to Europe will likely switch back to the Suez Canal, which could facilitate a steady return of more LNGCs, depending on the direction of events in the coming months.

The resumption of Suez Canal transits will benefit Qatari exports to Europe, with the the MEG country's exports to Europe likely to exceed those of previous years.

This will be led by the expected recovery in European LNG demand this year with the end of Russia/Ukraine gas transit deal, the conclusion of 2024/25 winter with lower gas stocks and looming sanctions on Russian LNG, compelling European buyers to seek more LNG from alternative sources.

Qatari LNG shipments to Europe fell in 2023 after the start of the Red Sea crisis in October of that year, minimising the flexibility of Qatari exports to European markets. Its share was further squeezed in 2024, with subdued LNG demand in Europe and the growing prominence of US and Russia becoming the prominent LNG suppliers for Europe, given their flexibility and proximity.

This trend could reverse in 2025, as the share of Qatari exports to Europe is likely to revive with the resumption of transits via the canal.

Meanwhile, Algeria could also regain its lost share of the Asian market if the Red Sea situation normalises, Drewry said.

Algeria mainly exports to Europe, but the country's exports to Asia, which were hampered by the Red Sea attacks, could also rise, especially if the US/China tariff war restarts.

Algerian LNG exports share to Asia rose to 9% in 2023 but declined to just 5% in 2024, due to the persisting Red Sea situation.

Drewry predicted no significant change in US/Asia vessel movements, as low freight rates and high vessel availability will allow exporters to avoid the canal transit costs and continue using the COGH.

This situation is similar to that with the Panama Canal, where, despite the ease in regulations, LNGCs continued to transit via COGH, thus avoiding the high canal costs and competition from other sectors.

LNGCs transiting between the US and Asia will continue to prefer COGH over Suez or Panama, as shipping economics will play a pivotal role in determining vessel routes.

Low freight rate projections for this year, due to ample vessel availability and lower LNG prices, will keep shipowners on edge, preventing them from paying high canal and shipping costs.

The US/Asia trade has been improving over the last couple of years, and further improvement is anticipated this year, despite increasing competition from Europe.

This trade will be supported by new US supply with the start up of key LNG projects, such as Plaquemines LNG (13.5 mill tonnes per annum) and Corpus Christi Phase 3 (10 mill tonnes).

A robust US/Asia trade, utilising the COGH as the preferred passage, will positively affect LNG shipping demand. However, the Suez route will be detrimental to rates, as long voyages will be cut short, curtailing the potential benefits of higher US/Asia trade and thereby putting pressure on rates further.

Excess fleet supply (with a high number of deliveries expected this year) and new capacity additions towards 2H25 would continue to depress rates.

Although an immediate return to the Suez Canal seems improbable, a steady return of Qatari cargoes is likely. Moreover, the sudden shift from COGH to Suez will be detrimental to LNG shipping, as longer voyages prevented freight rates from falling further last year.

Thus, LNG shipping will need COGH as the preferred passage, at least until 2025/26 for vessels sailing from the US to Asia to increase the usage of an expanded fleet.

Vessel availability is expected to remain high in 2025/26 with longer voyages providing some respite to depressed freight rates, Drewry concluded.

SHELL: UK energy giant, Shell has reported robust CFFO of $13.2 bill for the fourth quarter of last year and a CFFO of $54.7 bill and free cash flow of $39.5 bill for the full year.

Adjusted 4Q24 earnings of $3.7 bill reflected lower prices and margins, higher exploration well write-offs, and the non-cash impact of expiring hedging contracts on LNG trading and optimisation results.

Structural cost reductions of $3.1 bill achieved since 2022, met the 2023 Capital Markets Day (CMD23) target a year early, with significant progress also reported against the other CMD23 financial targets1.

A focus on disciplined capital allocation drove down 2024 cash capex to $21.1 bill. The capex range for the full year 2025 is expected to be lower than the 2024 range, with more guidance to come at the Capital Markets Day in March, Shell said.

Net debt increased by $3.6 bill over the quarter to $38.8 bill, reflecting the recognition of the LNG Canada pipeline lease liability. Net debt at the end of the year was $4.7 bill lower than at the beginning of the year.

In the LNG space, 4Q24 liquefaction volumes were 7.1 mill tonnes, compared to 7.5 mill in the previous quarter, while sales volumes were down to 15.5 mill tonnes, compared to 17 mill in 3Q24.

For the first quarter of this year, Shell forecast liquefaction volumes of between 6.6 and 7.2 mill tonnes.

This reflected Pearl GTL being back in operation, while the LNG liquefaction volumes outlook was impacted by lower feedgas supplies.

"2024 was another year of strong financial performance across Shell. Despite the lower earnings this quarter, cash delivery remained solid and we generated free cash flow of $40 bill across the year, higher than 2023, in a lower price environment.

“Our continued focus on simplification helped to deliver over $3 bill in structural cost reductions since 2022, meeting our target ahead of schedule, whilst also making significant progress against all our other financial targets.

“We announce a 4% increase in our dividends and another $3.5 bill buyback programme, making this the 13th consecutive quarter of at least $3 bill of buybacks, all whilst further strengthening our balance sheet this year to position us well for the future.

We will outline the next steps in our strategy to deliver more value with less emissions at our Capital Markets Day in March," said CEO, Wael Sawan.

US ENERGY: US President Donald Trump end of the moratorium on new LNG export permits imposed by his predecessor Joe Biden in January, 2024 is seen as part of a series of planned policy moves to encourage more US energy production.

Biden paused new approvals pending a study into the environmental and economic effects of the booming export industry. This study was published last month.

US LNG output was set to more than double regardless of the moratorium. Before Biden stopped the new permit approvals, the government had already given the green light to projects that would increase LNG capacity to 200 mill tonnes per annum from around 90 mill tonnes. However, these projects were not affected by the ban.

New permits issued by Trump's government would likely increase export capacity from 2030 onwards, as it obviously takes several years to build LNG plants.

The US is already the world's largest LNG exporter shipping 88.3 mill tonnes last year. This year, three new plants should add nearly 50 mill tonnes per annum to the capacity.

Venture Global's Plaquemines LNG plant in Louisiana, which at its peak would add 20 mill tonnes per annum and Cheniere Energy's 10 mill tonne Stage 3 expansion at Corpus Christi, Texas, both began producing LNG last month but are still under construction.

The long delayed joint venture between ExxonMobil and QatarEnergy - Golden Pass LNG Texas - is also expected to produce its first LNG this year and at its peak would have a capacity of 18.1 mill tonnes per annum.

The following are the projects that were impacted by the halt to new permits, which could now be in a better position to move forward due to Trump's decision and could add another 100 mill tonnes per annum to US export capacity, according to Reuters analysis:

TEXAS:
- Sempra Infrastructure's Port Arthur expansion (13 mill tonnes)
- Cheniere Energy's Corpus Christi 8 and 9 (3 mill)

LOUISIANA
- Commonwealth LNG (9.5 mill)
- Venture Global LNG's CP2 project (20 mill)
- Energy Transfer's Lake Charles LNG facility (15.5 mill)
- Glenfarne Group's Magnolia LNG (8.8 mill)
- Gulfstream LNG (4.2 mill)
- Argent LNG (25 MTPA)

EXPANSION

There are also a number of plants that already have US Department of Energy (DoE) export permits but need approvals to increase their capacity.

They include Venture Global LNG's Plaquemines and Calcasieu Pass plants, and Kinder Morgan's Elba Island LNG plant.

There are also a number of other projects in earlier stage of development that could benefit from the restart of permit processing. They include EOS FLNG, Barca LNG in Texas, plus CE FLNG, Main Pass Energy Hub FLNG and Monkey Island LNG in Lousiana.

In Mexico, the Mexico Pacific LNG project located in Saguaro will liquefy US gas and therefore needs a DoE permit.

New Fortress Energy's Altamira FLNG plant on Mexico's Pacific coast was the only project to get a license to export to countries not covered by free-trade agreements during the pause, Reuters said.

VENTURE GLOBAL: Venture Global’s Class A common stock shares started trading on the New York Stock Exchange (NYSE) last Friday under the symbol ‘VG’.

Venture Global’s IPO of 70 mill shares of its Class A common stock, par value $0.01 was priced at $25 per share and was concluded yesterday.

The LNG developer also granted the underwriters a 30-day option to purchase up to an additional 10.5 mill shares.

Goldman Sachs, JP Morgan and BofA Securities acted as joint lead book-running managers, while ING, RBC Capital Markets, Scotiabank, Mizuho, Santander, SMBC Nikko, MUFG, BBVA, Loop Capital Markets, Natixis, Deutsche Bank Securities, Wells Fargo Securities and Truist Securities acted as joint book-running managers for the offering.

National Bank of Canada Financial Markets, Raymond James, Regions Securities, Guggenheim Securities and Tuohy Brothers acted as co-managers.

A registration statement relating to the offering was filed with the US Securities and Exchange Commission (SEC), which was declared effective on 23rd January, 2025. ■

Explanatory Notes

- The tables do not include the following types of LNG facilities:
  - Small marine satellite terminals receiving LNG from liquefaction plants in their own country (such as exist in Norway) or which receive LNG transhipped from nearby reception terminals in their own country (such as in Japan)
  - Satellite LNG storage facilities that receive LNG transported only by road or rail
- Expansions of LNG reception terminals are only shown if they involve new storage tanks
- Where there is a blank in the table the information is uncertain or unknown.

In addition to our own database, the information in these tables has been derived and cross-referenced from multiple sources, including GEM, IEEJ, IGU, GIE, GIIGNL and facility operators/ developers.

Comments, corrections or additional information would be most welcome. They should be sent to alexander@lngjournal.com

Conventional LNG Terminals

Country	Location (Project)	Owners	Start up	Nom. Capacity (MTPA)	Storage Tanks	Storage Capacity
Belgium	Zeebrugge	Fluxys	1987	6.6	5	566,000
Canada	St. John (Canaport) LNG	Repsol	2009	7.1	3	480,000
Chile	Mejillones LNG	Tractebel Engie, Ameris Capital AGF	2010	1.5	1	187,000
	Quintero	ENAP, Metrogas, Enagas	2009	3.8	3	334,000
China	Beihai LNG	PipeChina	2013	6.0	4	640,000
	Caofeidian LNG	PetroChina	2012	10.0	8	1,280,000
	Caofeidian Xintian LNG	China Suntien Green Energy Corp.	2023	5.0	2	–
	Dalian LNG	PipeChina	2011	6.0	3	480,000
	Dongguan LNG	JOVO Energy	2010	1.5	2	160,000
	Fujian LNG	CNOOC	2008	6.3	6	960,000
	Guangdong Dapeng LNG	CNOOC	2006	6.8	4	640,000
	Hainan LNG	PipeChina	2014	3.0	2	320,000
	Hainan Transfer Station	PetroChina	2020	0.6	2	40,000
	Jiangsu LNG	PetroChina	2011	10.0	5	1,080,000
	Jieyang LNG	PipeChina	2018	4.2	3	480,000
	Nansha LNG	Guangzhou Gas	2023	1.0	2	160,000
	Pinghu LNG	Zhejiang Hangjiaxin Clean Energy	2022	1.0	2	200,000
	Qidong LNG	Guanghui Energy	2009	4.0	5	620,000
	Qingdao LNG	Sinopec	2006	7.0	6	960,000
	Shanghai (Yangshan) LNG	CNOOC	2009	3.0	5	895,000
	Shanghai Peak Shaving	Shenergy	2008	1.5	5	320,000
	Shenzhen Peak Shaving	Hua'an	2012	0.8	1	80,000
	Shenzhen Diefu LNG	PipeChina	2018	4.0	4	640,000
	Tianjin - Nangang LNG	Sinopec	2018	6.0	4	640,000
	Tianjin LNG	PipeChina	2013	6.0	7	397,000
	Tianjin Binhai LNG	Beijing Gas	2023	5	10	–
	Wenzhou LNG	Zhejiang Energy, Sinopec	2023	3.0	4	–
	Yancheng LNG	CNOOC	2022	3.0	4	880,000
	Zhangzhou LNG	PipeChina	2024	3.0	3	
	Zhejiang LNG	CNOOC	2018	6.0	6	960,000
	Zhoushan LNG	ENN	2018	5.0	4	640,000
	Zhuhai LNG	CNOOC	2014	3.4	3	480,000
Dominican Republic	Andres LNG	AES Andres	2003	1.9	1	160,000
France	Dunkerque Le Clipton	EDF, Fluxys, TotalEnergies	2016	9.5	3	600,000
	Fos-sur-Mer	TotalEnergies, Elengy	2010	9.2	4	410,000
	Montoir-de-Bretagne	Elengy	1980	8.0	3	360,000
Greece	Revithoussa	DESFA	2000	7.1	3	225,000
India	Cochin	Petronet	2013	5.0	2	368,000
	Dabhol	GAIL, NTPC	2007	5.0	3	480,000
	Dahej	Petronet	2004	17.5	6	932,000
	Ennore LNG	IndianOil LNG	2019	5.0	2	360,000
	Hazira	Shell, TotalEnergies	2005	5.0	2	320,000
	Mundra LNG	Adani, GSP	2019	5.0	2	320,000
	Dhamra LNG	Adani, TotalEnergies	2023	6.5	2	360,000
	Chhara LNG	HPLNG	2024	5.0	2	400,000
Indonesia	Arun Conversion	Pertamina	2015	3.0	4	508,000
Italy	Panigaglia	Snam	1963	2.5	2	100,000
	Rovigo Adriatic LNG	QatarEnergy, ExxonMobil, Snam	2009	6.6	2	250,000
Jamaica	Montego Bay	New Fortress Energy	2020	0.5	7	7,000
Japan	Chita	JERA, Toho Gas	1977	24.0	14	1,560,000
	Fukuoka	Saibu Gas	1993	0.8	1	70,000
	Futtsu	JERA	1985	20.0	10	1,110,000
	Hachinohe	ENEOS	2015	1.6	2	280,000
	Hatsukaichi	Hiroshima Gas	1996	0.9	2	170,000
	Hibiki LNG	Saibu Gas, Kitakyushu Gas	2014	4.0	2	360,000
	Higashi-Ogishima	Tokyo Electric	1984	15.0	9	540,000
	Himeji	Kansai Electric, Osaka Gas	1979	12.9	15	1,360,000
	Hitachi LNG	JERA	2015	2.2	2	230,000
	Ishikari LNG	Hokkaido Gas	2012	1.4	1	180,000
	Joetsu LNG	JERA	2012	2.3	3	540,000
	Kagoshima	JERA	1996	0.2	1	86,000
	Kawagoe	Chubu Electric	1997	8.0	3	480,000
	Mizushima	Chugoku Electric, ENEOS	2006	1.7	2	320,000
	Nagasaki LNG	Saibu Gas	2003	0.1	1	35,000
	Nakagusuku LNG	Okinawa Electric	2012	0.7	2	280,000
	Negishi	TEPCO, JERA	1969	11.0	14	1,180,000
	Niigata	Tohoku Electric	1984	10.0	8	720,000

Conventional LNG Terminals (Continued)

Country	Location (Project)	Owners	Start up	Nom. Capacity (MTPA)	Storage	
					Tanks	Capacity
Japan (continued)	Ogishima	JERA	1998	3.0	4	850,000
	Oita	Kyushu Electric	1990	5.1	5	460,000
	Sakai	Kansai Electric	2006	6.4	4	420,000
	Sakaide	Shikoku Electric, Cosmo Oil, Shikoku-Gas	2010	1.2	1	180,000
	Senboku	Osaka Gas	1972	12.5	20	1,675,000
	Shin Sendai	Tohoku Electric	2016	1.0	2	320,000
	Sodegaura	JERA	1973	29.4	35	2,660,000
	Sodeshi Shimizu	Shizuoka Gas, ENEOS	1996	2.9	3	337,200
	Soma LNG	JAPEX	2018	1.5	2	460,000
	Tobata Ward	Kita-Kyushu LNG	1977	7.6	8	480,000
	Toyama LNG	Hokuriku Electric	2018	1.8	1	180,000
	Yanai	Chugoku Electric	1990	2.4	6	480,000
	Yokkaichi	Chubu Electric	1987	7.2	2	320,000
Kuwait	Al Zour LNG	KIPIC	2022	22.0	8	1,800,000
Malaysia	Pengerang LNG	Petronas	2017	3.5	2	400,000
Mexico	Energia Costa Azul	Sempra	2008	7.6	2	320,000
	Manzanillo	Samsung, KOGAS, Mitsui	2012	3.8	2	300,000
Netherlands	Maasvlakte Gate Terminal	Gasunie	2011	8.9	3	540,000
Panama	AES Costa Norte LNG	AES	2018	1.5	1	130,000
Philippines	PHLNG	AG&P	2023	5.0	1	137,512
Poland	Swinoujscie LNG	Polskie LNG	2015	3.6	2	320,000
Portugal	Sines	REN	2004	5.6	3	390,000
Puerto Rico	Penuelas	EcoElectrica	2000	1.4	1	160,000
Singapore	Singapore LNG	Singapore LNG Corp.	2013	11.0	4	800,000
South Korea	Boryeong	GS Energy	2017	10.8	6	1,200,000
	Gwangyang	POSCO Energy	2005	7.1	5	730,000
	Incheon	KOGAS	1996	54.4	23	3,480,000
	Pyeongtaek	KOGAS	1986	41.0	23	3,360,000
	Samcheok	KOGAS	2014	11.6	12	2,400,000
	Tongyeong	KOGAS	2002	26.6	17	2,600,000
	Jeju Island	KOGAS	2019	1.1	2	90,000
	Korea Energy Terminal	SK Gas, KNOC	2024	2.4	–	–
Spain	Bahia de Bizkaia LNG	BP, Enagás, EVE	2003	6.9	3	450,000
	Barcelona	Enagás	1969	12.6	6	760,000
	Cartagena	Enagás	1989	8.7	5	587,000
	Huelva	Enagás	1988	8.7	5	619,500
	Mugardos	Reganosa	2007	2.6	2	300,000
	Sagunto	Enagás	2006	6.4	4	600,000
	El Musel	Enagás	2023	5.8	2	300,000
Taiwan	Taichung	CPC	2009	7.0	6	960,000
	Yung-An	CPC	1990	10.5	6	690,000
Thailand	Map Ta Phut LNG	PTT	2011	19.0	6	940,000
Turkey	Izmir	EgeGaz	2006	10.6	2	280,000
	Marmara Ereglisi	BOTAS	1994	4.2	3	255,000
UK	Dragon LNG	Shell, Ancala Partners	2009	6.5	2	320,000
	Isle of Grain	National Grid	2005	14.8	8	1,000,000
	South Hook LNG	QatarEnergy, ExxonMobil, TotalEnergies	2009	15.6	5	775,000
United States	Everett Marine Terminal	Constellation Energy	1971	5.1	2	155,000
Vietnam	Thi Vai LNG	PetroVietnam Gas	2023	1.0	1	180,000

FSRU Terminals

Country	Location (Project)	Owners	Start up
Argentina	Escobar GasPort	Excelerate/Enarsa	2011
	Bahia Blanca	YPF	2023
Bangladesh	Moheshkhali	Excelerate, PetroBangla	2018
	Cox's Bazar	Summit Power International, Excelerate Energy	2019
Brazil	Pecem, FSRU	Petrobras	2009
	Guanabara Bay FSRU	Petrobras	2009
	Salvador, Bahia FSRU	Petrobras	2013
	Porto Sergipe FSRU	Golar LNG/Stonepeak	2020
	Porto do Acu FSRU	GNA	2020
	Terminal Gás Sul	New Fortress Energy	2024
	Barcarena FSRU	NFE	2024
	GNL de Sao Paulo	edge	2024
	KARMOL LNGT Sepetiba	Karpowership	2024
China	Tianjin FSRU	CNOOC, Hoegh, various	2013
Croatia	Hrvatska LNG	Hrvatska Elektroprivreda Plc, Plinacro Ltd	2021
Colombia	Cartagena FSRU	Promigas, Sociedad Portuaria El Cayao	2016
Egypt	Ain Sokhna, Suez	EGAS, BW Gas	2015
El Salvador	Acajutla	Energía del Pacífico	2022
Finland	Inkoo FSRU	Gasgrid Finland	2022
France	Le Havre	TotalEnergies	2023
Germany	Wilhelmshaven FSRU	Uniper	2022
	Lubmin FSRU	Deutsche ReGas	2022
	Brunsbüttel	RWE	2023
Ghana	Tema LNG	Helios/GNPC	2021
Greece	Revithoussa FSU	DESFA	2022
	Alexandroupolis	Gastrade	2024

Country	Location (Project)	Owners	Start up
Hong Kong, China	FSRU Bauhinia	CLP Power	2023
India	Jaigarh (Mothballed)	H-Energy	2022
Indonesia	Lampung	Hoegh LNG, PGN LNG	2014
	Nusantara (Jakarta Bay)	Golar LNG, Pertimana	2012
	Benoa LNG	PT Pertagas Niaga	2016
	Amurang	Karadeniz	2020
	Jawa Satu FSRU	Pertamina	2021
Italy	Livorno	OLT Offshore LNG Toscana	2013
	Piombino	Snam	2023
Jamaica	Old Harbour	Golar FSRU, New Fortress	2019
Jordan	Aqaba, Jordan	Golar LNG	2015
Lithuania	Klaipeda	Klaipedos Nafta Hoegh LNG	2014
Malaysia	Malacca FSRU	Petronas	2012
Malta	FSU Armada Mediterrana	ElectroGas	2016
Myanmar	Thanlyin	CNTIC Vpower	2020
Netherlands	Eemshaven	Gasunie	2022
Pakistan	Port Qasim	Excelerate, Engro Corp	2015
	Port Qasim	BW-Mitsui, PGP Consortium	2017
Philippines	PHLNG	AG&P International	2023
	FGEN Batangas LNG	First Gen Corp.	2023
Russia	Kaliningrad FSRU	Gazprom	2020
Senegal	Dakar	KarMOL	2023
Turkey	Iskenderun & Saros FSRUs	BOTAS	2016 & 2023
	Aliaga (ETKI LNG)	Etki Liman	2017
UAE	Ruwais, Abu Dhabi	Gasco (UAE)	2016
	Jebel Ali Port, Dubai	DSA (UAE)	2010

Future LNG Import Projects

Country	Location/Project	Owners	Start up	Nom. Capacity (MTPA)	Storage Tanks	Storage Capacity	Status
Albania	Port of Vlora FSRU	Excelerate Energy, ExxonMobil	–	3.5	–	–	Speculative
Australia	Port Phillip Bay FSRU	Vopak	2024	–	–	–	Speculative
	Geelong FSRU	Viva Energy	2024	–	–	–	Speculative
	Adelaide FSRU	Venice Energy	2024	–	–	–	Speculative
	Port Kembla FSRU	Squadron Energy	2026	1.9	1	170,000	U. Construction
Bangladesh	Matarbari LNG	Petrobangla	2028	7.5	–	–	Speculative
	Payra FSRU	Excelerate Energy	2028		–	–	Speculative
Belgium	Zeebrugge Exp. I	Fluxys	2024	4.6	–	–	U. Construction
	Zeebrugge Exp. II	Fluxys	2026	1.3	–	–	U. Construction
Brazil	Tergás Rio Grande LNG	Grupo Cobra	2024	1.61	–	–	Speculative
	Geramar FSRU	–	2026	–	–	–	Speculative
	Porto Norte Fluminense FSRU	Porto Norte Fluminense SA	2027	5.64	–	–	Speculative
	Imetame LNG	Imetame	2025	–	–	–	Speculative
China	Penglai LNG	Shandong Penglai Baota Ina Natural Gas Co., Ltd.	2026	2.8	–	–	Proposed
	Wuhan LNG	Hubei Minsheng Petroleum Liquefied Gas Co., Ltd.	2035	1.86	–	–	Speculative
	Zhiwan Island LNG	Macau Gas Co.	–	5	–	–	Speculative
	Yueyang LNG	Yueyang LNG Co., Ltd.	2024+	1.5	–	–	Speculative
	Yangjiang LNG	Guangdong Yangjiang Hailing Bay LNG Co., Ltd.	2024+	2.8	2	–	U. Construction
	Rudong LNG (Jiangsu Guoxin)	Jiangsu Guoxin LNG Co., Ltd.	2024	2.95	–	–	U. Construction
	Jiangyin LNG (Garson Gas)	Jiangsu Jiasheng Gas Co., Ltd.	2024	3	–	–	U. Construction
	Huizhou LNG	Guangdong Huizhou LNG Co., Ltd.	2024	4	–	–	U. Construction
	Longkou	PipeChina	2024	5	6	1,420,000	U. Construction
	Yingkou LNG	China Urban Rural Energy	2025	6.5	4	800,000	U. Construction
	Yancheng LNG Expansion	CNOOC	2024	3	–	1,620,000	U. Construction
	Yantai LNG	China Urban Rural Energy	–	5.9	5	1,000,000	U. Construction
Colombia	Buenaventura FSRU	Unidad de Planeación Minero Energética (UPME)	2024	–	–	–	Speculative
Cyprus	Vasilikos FSRU	DEFA	2024	0.6	–	–	U. Construction
Ecuador	Jambelí FSRU	Sycar LLC	2025	0.38	–	–	Proposed
Estonia	Paldiski LNG	Espa	2024	1.8	–	–	Proposed
Germany	Stade LNG	Buss Group, Dow Chemical, Fluxys, Partners Group	2026	9.78	–	–	Proposed
	TES Wilhelmshaven LNG	Tree Energy Solutions	2025	11.76	–	–	Proposed
	Stade FSRU	German company Hanseatic Energy Hub	2024	3.5	–	–	U. Construction
Greece	Dioriga FSRU	Motor Oil	2024	1.91	–	–	Proposed
	Argo FSRU	Mediterranean Gas	2024	3.38	–	–	Proposed
	Thessaloniki FSRU	Edison, Hellenic Petroleum	2025	5.37	–	–	Proposed
India	Jaigarh LNG	H-Energy	–	8	–	–	Speculative
	Kakinada FSU	H-Energy	2024	4	–	–	Speculative
	Kukrahati LNG	H-Energy	2024	3	–	180,000	Speculative
	Chhara LNG Terminal	Hindustan Petroleum	2025	5	–	–	U. Construction
	Karaikal LNG	AG&P	TBC	5	–	–	Speculative
Indonesia	Karimun Island LNG	Panbil Group	2024	–	–	–	Speculative
	Sengkang LNG	Energy World	–	2	–	–	U. Construction
Ireland	Mag Mell FSRU	Predator Oil & Gas	–	1.91	–	–	Speculative
Italy	Porto Torres FSRU	Snam	2024	0.5	–	–	Proposed
	Gioia Tauro LNG	Iren Group, Sorgenia	2026	8.6	–	–	Proposed
	Portovesme FSRU	Snam SpA	2024	–	–	–	Speculative
Morocco	Jorf Lasfar LNG	SIGER/ERGIS Group	2025	5.15	–	–	Speculative
Mozambique	Matola FSRU	Gigajoule, TotalEnergies, CTB, Matola Gas Co.	2025	0.5	–	–	Speculative
Myanmar	Mee Laung Gyaing FSRU	Supreme Group, ZHEFU Hydropower	2025+	–	–	–	Speculative
	Ahlone LNG	TTCL	2025+	–	–	–	Speculative
	Thilawa LNG	Eden Group, Marubeni Corp., Mitsui, Sumitomo Corp.	2026	–	–	–	Speculative
Pakistan	Tabeer Energy FSRU	Mitsubishi	–	5.7	–	–	Speculative
Philippines	Vires FSRU	Argo Group	–	3	–	–	Speculative
	Pagbilao Power	Energy World	–	3	2	260,000	U. Construction
Poland	Gdańsk FSRU	PGNiG	2028	8.82	–	–	Speculative
South Africa	Richards Bay FSRU	South Africa Department of Public Enterprises	2027	1	–	–	Speculative
South Korea	Dangjin LNG	POSCO	2027	3.5	–	–	Proposed
	Hanyang LNG	Hanyang Group	2024	–	–	–	Speculative
Sri Lanka	New Fortress Colombo LNG	New Fortress Energy	–	0.71	–	–	Speculative
Taiwan	Hsieh-Ho LNG	Taipower	2025	1.8	–	–	Proposed
	Taichung (TaiPower) LNG	Taipower	2025	3	–	–	Proposed
Thailand	Chana LNG	–	2028	2	–	–	Speculative
Vietnam	Hai Linh	Hai Linh Co. Ltd.	2020	3	3	219,000	Mothballed
	Mui Ke Ga FSRU	B.Grimm Power, Energy Capital Vietnam, Gunvor	2025	1.5	–	–	Proposed
	Son My LNG	AES, PetroVietnam	2026	3.6	–	–	Proposed
	Thai Binh FSRU	–	2026	0.5	–	–	Speculative
	South West FSRU	–	2030	1	–	–	Speculative
	Bac Lieu LNG	Delta Offshore Energy	–	2	–	–	Speculative
	Cat Hai FSRU	Chubu Electric, ExxonMobil, Government of Hai Phong, TEPCO	2030	3	–	–	Speculative
	Khanh Hoa LNG	Millenium Energy	2030	3	–	–	Speculative
	Long Son LNG	EVN	2025	4.4	–	–	Speculative
	Tien Lang FSRU	ExxonMobil, Chubu Electric Power, Tokyo Electric Power Co.	2026	–	–	–	Speculative
	Ca Na LNG	Novatek	2024	–	–	–	Speculative
	Chan May LNG	Chan May LNG	2024	–	–	–	Speculative
	Vung Ang LNG	KG Electric Power Corp., PECC2, Siemens	2026	–	–	–	Speculative
	Hai Lang LNG	T&T Group, Hanwa, KOGAS, KOSPO	2026	1.5	2	160,000	U. Construction

LNG Export Plants

Country	Location/Project	Shareholders	Start up	Liquefaction		Storage	
				Trains	Nom. capacity (MTPA)	No. of tanks	Capacity m^3
UAE	Das Island	ADNOC, Mitsui, BP, TotalEnergies	1977/1994	3	5.7	3	240,000
Algeria	Arzew	Sonatrach	1964-2014	13	20.8	6	920,000
	Skikda	Sonatrach	1980/2013	4	7.9	5	308,000
Angola	Soyo	Sonangol, Chevron, BP, Eni, TotalEnergies	2012	1	5.2	2	370,000
Australia	NWS LNG	BP, Chevron, MIMI, Shell, Woodside Energy, CNOOC	1989-2004	5	16.3	6	520,000
	Darwin LNG	Santos, Eni, INPEX, JERA, Tokyo Gas	2006	1	3.7	1	188,000
	Australia Pacific LNG	ConocoPhillips, Origin, Sinopec	2016	2	9.0	2	320,000
	Gladstone LNG	Santos, Petronas, TotalEnergies, KOGAS	2015-2016	2	7.8	2	280,000
	Gorgon LNG	Chevron, Shell, ExxonMobil, Osaka Gas, Tokyo Gas, JERA	2016-2017	3	15.6	2	360,000
	Pluto LNG	Woodside Energy, Kansai Electric, Tokyo Gas	2012	1	4.9	2	240,000
	Queensland C. LNG	Shell, CNOOC	2014	2	4.5	2	280,000
	Wheatstone LNG	Chevron, KUFPEC, Woodside Petroleum, Kyushu Electric Power Co., PEW	2017	2	8.9	2	300,000
	Ichthys LNG	INPEX, TotalEnergies, CPC, Tokyo Gas, Osaka Gas, Kansai Electric, JERA, Toho Gas	2018	2	8.9	2	330,000
	Prelude FLNG	Shell, INPEX, CPC, KOGAS	2018	1	3.6	6	228,000
Brunei	Brunei LNG	Gov. of Brunei, Shell, Mitsubishi	1972-74	5	7.2	3	195,000
Cameroon	Cameroon FLNG	Golar LNG	2018	4	2.4	1	125,000
Egypt	Damietta	Eni, EGAS, EGPC	2004	1	5.0	2	300,000
	Idku	EGPC, EGAS, Shell, Petronas, TotalEnergies	2005	1	7.2	2	280,000
Equ. Guinea	EG LNG	Marathon, Sonagas, Marubeni	2007	1	3.4	2	272,000
Indonesia	Bontang (E-H)	Pertamina, VICO, JILCO, TotalEnergies	1990-1998	4	11.5	5	635,000
	Dongi-Senoro	Medco Energi, Pertamina, Mitsubishi	2015	1	2.0	1	170,000
	Tangguh	BP, Mitsubishi, Inpex, CNOOC, JX Nippon, KG Mitsui, LNG Japan	2008-2023	3	11.4	2	340,000
Malaysia	Malaysia LNG	Petronas, Shell, Sarawak, Mitsubishi, Nippon Oil	1983-2016	9	29.3	6	445,000
	PFLNG Satu	Petronas	2016	1	1.2	4	177,000
	PFLNG Dua	Petronas	2020	1	1.5	4	177,000
Mexico	Altamira Fast LNG	New Fortress Energy	2024	1	1.4	–	–
Mozambique	Coral Sul FLNG	Eni, ExxonMobil, CNPC, GALP, KOGAS, ENH	2022	1	3.4	8	227,840
Nigeria	Bonny Island	NNPC, Shell, TotalEnegies, Eni	1999-2007	6	22.2	6	505,200
Norway	Snøhvit LNG	Equinor, TotalEnergies, Petoro, Neptune Energy, Wintershall DEA Norge	2007	1	4.2	2	250,000
Oman	Oman LNG	Oman Gov., Shell, TotalEnergies, Korea LNG, Mitsubishi, Mitsui, Partex O&G, Itochu Corp.	2000	3	10.4	4	480,000
Papua New Guinea	PNG LNG	ExxonMobil, Oil Search, Santos, JX Nippon Oil	2014	2	8.3	2	320,000
Peru	Pampa Melchorita	Hunt Oil, Shell, Marubeni, SK Group	2010	1	4.5	2	260,000
Qatar	Ras Laffan	QatarEnergy, Shell, ExxonMobil, TotalEnergies, ConocoPhillips et al.	1997-2010	14	77.4	18	2,340,000
Republic of the Congo	Congo FLNG Ph. I	Eni	2024	1	0.6	1	177,000
Russia	Sakhalin-2 LNG	Gazprom, Sakhalin Energy, Mitsubishi, Mitsui	2009	2	9.6	2	200,000
	Yamal LNG	Novatek, TotalEnergies, CNPC, Silk Road Investment Fund	2017-2019	3	17.4	4	640,000
	Portovaya LNG	Gazprom	2022	1	1.5	-	-
Trinidad & Tobago	Atlantic LNG	BP, Shell, NGC	1999-2005	4	15.3	4	640,000
USA	Sabine Pass LNG	Cheniere	2016-2022	6	30.0	5	800,000
	Corpus Christi LNG	Cheniere	2019-2021	3	15.0	3	480,000
	Freeport LNG	Freeport LNG, JERA, Osaka Gas	2019-2020	3	15.5	3	480,000
	Cameron LNG	Sempra, TotalEnergies, Mitsui, Mitsubishi	2019	3	15.0	3	480,000
	Calcasieu Pass LNG	VentureGlobal	2022-2023	18	11.3	2	440,000
	Cove Point LNG	BHE GT&S, Dominion Energy, Brookfield Asset Management	2017	1	5.3	7	695,000
	Elba Island LNG	Kinder Morgan, EIG Energy, Blackstone	2019-2020	10	2.5	5	560,000
Yemen	Balhaf LNG (Mothballed)	TotalEnergies, Hunt Oil, SK Innovation, Hyundai, KOGAS, Yemen Gas Corp., GASSP	2009	2	6.7	2	320,000

LNG Export Projects U. Construction

Country	Project	Project Developers	Planned Start Up	Number of Trains	Capacity In MTPA
Canada	LNG Canada	Shell, Petronas, PetroChina, Mitsubishi	2025	2	14
	Woodfibre LNG	Pacific Energy Corp., Enbridge	2027	2	2.2
Indonesia	Sengkang LNG	Energy World	2023+	4	2
Malaysia	ZLNG FLNG	Petronas	2027	1	2
Mauritania	Greater Tortue Ahmeyim FLNG	BP, Kosmos Energy	2024	–	2.52
Mexico	Costa Azul Export	Sempra Energy, TotalEnergies	2024	1	3.25
Mozambique	Mozambique LNG Ph. I	TotalEnergies, Mitsui, ONGC, ENH, PTTEP, Bharat Petroleum, Oil India	2024+	2	–
Nigeria	Nigeria LNG Expansion	Nigeria LNG	2024	1	8
Qatar	Ras Laffan Expansion I	QatarEnergy	2026	4	33
	Ras Laffan Expansion II	QatarEnergy	2027	2	16
Russia	Ust Luga LNG	RusKhimAlyans	2027	2	13
	Arctic LNG 2 T1	Novatek et al	2024+	1	6.6
United States	Golden Pass LNG T1-2	Golden Pass LNG	2024	2	12
	Golden Pass LNG T3	Golden Pass LNG	2025	1	6.03
	Corpus Christi LNG Stage 3	Cheniere Energy	2027	7	11.48
	Plaquemines LNG Ph. I	Venture Global	2024	1	10
	Plaquemines LNG Ph. II	Venture Global	2025	1	10

Future LNG Export Projects

Country	Project	Project Developers	Estimated Start Up	Number of Trains	Capacity In MTPA
Argentina	Vaca Muerta (YPF) LNG	YPF	2024+	–	5.37
Australia	Browse FLNG	Woodside Energy, Japan Australia LNG, Shell, BP, PetroChina	–	2	11.4
	Darwin LNG Life Extension	Santos, SK E&S, JERA, INPEX, Eni SpA, Tokyo Gas	2025	1	3.7
	Pluto LNG T2	Woodside Burrup Train 2A Pty Ltd., Global Infrastructure Partners	2026	1	5
Cameroon	Etinde FLNG	Perenco, Bowleven	2023+	–	1.3
Canada	Bear Head LNG	Bear Head LNG	2027	4	12
	Cedar FLNG	Haisla Nation, Pembina Pipeline Corp.	2027	–	3
	Energie Saguenay LNG	GNL Quebec	2026	2	11
	Ksi Lisims FLNG	Ksi Lisims LNG GP Ltd.	2027	–	12
	Placentia Bay FLNG	Horizon Maritime Services, LNG Newfoundland and Labrador Ltd.	2030	–	4
	Tilbury Island LNG T1	FortisBC	2026	1	0.9
	Tilbury Island LNG T2	FortisBC	2028	1	2.5
Equatorial Guinea	Fortuna FLNG	New Fortress Energy	–	1	–
Gabon	Boudji FLNG	Petronas	–	–	–
Guinea	Guinea LNG	West Africa LNG Group	2026+	1	–
Indonesia	Abadi FLNG	INPEX Masela Ltd.	2030	–	9.5
Israel	NewMed FLNG	NewMed Energy	2026	–	5
Mauritania	New Fortress Banda LNG	New Fortress Energy	2024	–	1.4
Mexico	Mexico Pacific LNG Ph. I	AECOM Capital, DKRW Energy	2025	2	9.4
	Mexico Pacific LNG Ph. II	AECOM Capital, DKRW Energy	2026+	1	4.7
	AMIGO LNG	Epcilon LNG, LNG Alliance	2026	1	4.2
	Vista Pacifico LNG	Sempra Energy	2025+	–	4
	Lakach FLNG	New Fortress Energy	–	1	1.4
	Altamira FLNG	New Fortress Energy	–	2	2.8
Mozambique	Rovuma LNG	Eni, ExxonMobil, CNPC, ENH, Galp, KOGAS	2025+	2	15.2
Nigeria	Brass LNG	Brass LNG Ltd.	–	2	10
	Greenville LNG	Greenville LNG	–	1	1.1
	UTM Offshore FLNG	UTM Offshore	2026	–	1.52
Papua New Guinea	Papua LNG	TotalEnergies, ExxonMobil, Papua New Guinea Gov., Santos	2027	2	5.4
	PNG LNG Expansion	ExxonMobil, Kumul Petroleum, Santos, JX Nippon O&G, MRDC	2025	1	2.6
Republic of the Congo	Congo FLNG Ph. II	Eni Congo	2025	1	2.4
Russia	Yakutia LNG	A-Property, Globaltek, Zhejiang Energy	2027	–	18
	Far East LNG I	ExxonMobil, SODECO, ONGC, Rosneft	2027+	1	6.2
	Far East LNG II	ExxonMobil, SODECO, ONGC, Rosneft	2035	1	10
	Vladivostok LNG	Gazprom, INPEX, Itochu Corp., JAPEX, Marubeni Corp.	2025	3	1.5
	Arctic LNG II	Novatek	2027	–	19.8
	Obsky LNG	Novatek	2026	–	6.6
	Chernomorsky LNG	Gazprom	2025	–	1.5
	Arctic LNG III	OOO Arctic LNG 3	2032	–	19.8
	Kara LNG	Rosneft	2030	–	30
Tanzania	Tanzania LNG	Equinor, ExxonMobil, Ophir Energy, Pavilion Energy, Shell, TPDC	2027	2	10
United Arab Emirates	Ruwais (ex Fujairah) LNG	ADNOC	2027+	2	6
United States	Fourchon LNG	Energy World	–	1	2
	Alaska LNG	Alaska Gasline Development Corp.	2030	3	20.1
	Cameron LNG Expansion	Cameron LNG LLC	2026	1	6.75
	Commonwealth LNG	Commonwealth LNG	2026	6	9.3
	Corpus Christi LNG Midscale Expansion	Cheniere Energy	2031	2	3.28
	Delfin FLNG	Delfin LNG LLC	2026+	4	12
	Driftwood LNG T1-5	Tellurian	–	5	27.6
	Freeport LNG Expansion	Freeport LNG Dev.	2026	1	5.1
	Gulf LNG	KinderMorgan	–	2	10.86
	Lake Charles LNG	Energy Transfer	2026+	3	17.79
	Magnolia LNG	Glenfarne Group	–	4	8.8
	Port Arthur LNG Ph. I	PALNG Common Facilities Co., Port Arthur LNG, LLC	–	2	13.5
	Port Arthur LNG Ph. II	PALNG Common Facilities Co., Port Arthur LNG, LLC	–	2	13.5
	Texas LNG	Glenfarne Energy Transition	2027	2	4
	Rio Grande LNG Ph. I	NextDecade	2026	2	10.8
	Rio Grande LNG Ph. II	NextDecade	–	3	16.2
	Pointe LNG	Pointe LNG, Pointe Pipeline Co.	2026	3	6
	Repauno Works LNG	Delaware River Partners LLC	–	–	1.5
	Qilak LNG	Qilak Energyy	2026	–	4
	CP2 LNG Ph. I	Venture Global	2026+	9	10
	CP2 LNG Ph. II	Venture Global	2027+	9	10
	Delta LNG Ph. I	Venture Global	2028+	–	10
	Delta LNG Ph. II	Venture Global	2029+	–	10
	West Delta LNG Deepwater Port	LNG21 Group	2026+	6	6.1
	Grand Isle FLNG	New Fortress Energy	2025+	–	2.8

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