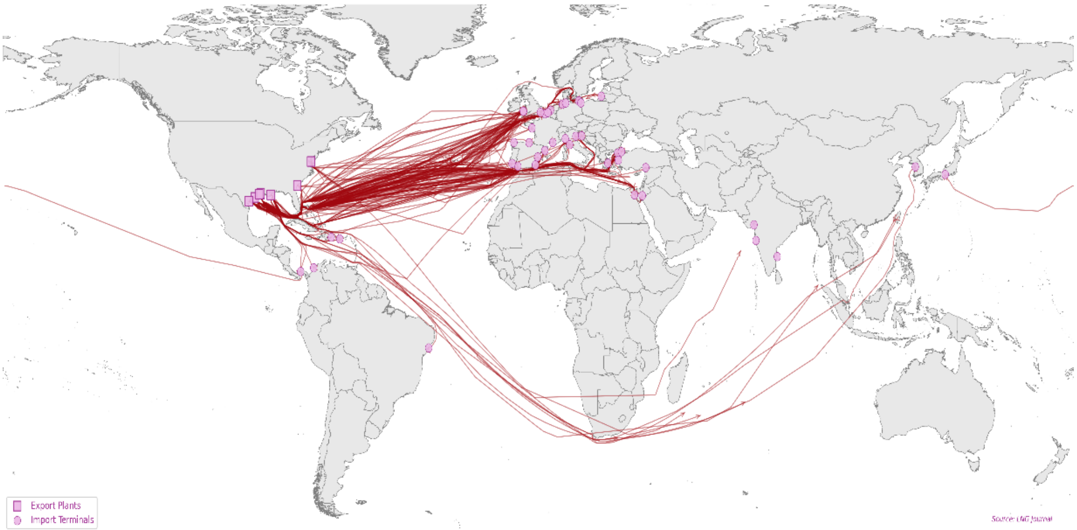
LNG Monthly Markets

LNG JOURNAL'S COMPREHENSIVE MONTHLY LNG DATA REPORT 20 FEBRUARY 2026

Summary & Highlights

Henry Hub spike hurts Atlantic-Pacific arbitrage as US cargoes flow to Europe



The defining story of January 2026 was the Henry Hub (HH) price spike. A prolonged cold snap across the United States drove the US gas benchmark to a monthly average of $7.72/MMBtu — an increase of $3.45 or 81 percent on December — with daily settlements briefly touching $30.72 on 23 January, according to the EIA. This was the most significant HH disruption since Winter Storm Uri in February 2021.

The immediate consequence was a collapse in Atlantic-to-Pacific trade flows. US LNG cargoes that would ordinarily have sailed east to Asia were instead absorbed by the Atlantic basin, where buyers — particularly in Europe — were willing to pay a premium over suddenly uncompetitive trans-Pacific arbitrage economics. Atlantic-to-Pacific volumes fell from 2.96MMt in December to just 1.18MMt in January, a loss of 4.5 percentage points of global trade share. The gap between Chinese landed spot prices (SHPGX) and US feedgas cost (HH) narrowed from $5.37 to just $2.50/MMBtu — barely enough to cover liquefaction, let alone shipping — while Chinese spot fell below European delivered prices for the first time in several months, by $1.49/MMBtu.

Global LNG exports fell 1.0 percent to 38.64MMt from December's 39.04MMt, though still 8.0 percent above year-ago levels. The Middle East was the standout performer, with exports rising 10.0 percent month on month to 8.55MMt as Ras Laffan lifted output sharply. Atlantic and Pacific basin exports, by contrast, both edged lower. Global liquefaction utilisation held at 87.0 percent, well within the elevated range sustained since the autumn ramp, and 7.0 percentage points above January 2025. European import concentration, as measured by the Herfindahl-Hirschman Index, surged to 4,849 — up over 1,000 points — reflecting the growing dominance of US supply in European LNG imports, which accounted for 68 percent of arrivals in January, according to our data.

Spot freight rates, which had spiked dramatically in November and December, reversed sharply in January, published Fearnleys data showed: East of Suez fell 52 percent and West of Suez fell 74 percent. Aggregate tonne-miles declined 21 percent month on month to 149,766, consistent with the shift towards shorter-haul Atlantic basin trade. Floating storage remained unremarkable at a peak of 8 vessels. European LNG terminal storage (ALSI) stood at 43.4 percent fill at month-end, 5.5 percentage points below the same date last year — a notable year-on-year deficit ◆

CONTENTS

Supply

Middle East at near-full capacity as Atlantic and Pacific basins ease on feedgas costs and production variability

Global LNG exports totalled 38.64MMt in January 2026 from 605 cargoes, down 1.0 percent from December's 39.04MMt but 8.0 percent above the 35.78MMt shipped in January 2025. The year-on-year growth rate has been running between 4 percent and 11 percent since October 2025, reflecting the structural capacity additions that came online through the second half of last year. Global liquefaction utilisation held at 87.0 percent, well within the elevated range sustained since the autumn ramp, and 7.0 percentage points above January 2025.

The Atlantic basin exported 16.58MMt, down 5.3 percent from December's 17.50MMt but up 21.5 percent year on year. Basin utilisation eased 4.3 percentage points to 84.8 percent, though the year-on-year improvement of 15.4 percentage points underlines the structural shift: the basin is running materially harder than a year ago, underpinned by the Plaquemines ramp and the continued build-out of US Gulf Coast capacity. The month-on-month decline was broad-based rather than concentrated in any single country. The United States contributed the largest absolute decrease, falling 0.39MMt to 10.67MMt (-3.5 percent), as the HH price spike constrained feedgas economics and reduced liquefaction throughput at the margin. Among the established US plants, Sabine Pass led at 2.67MMt, followed by Corpus Christi at 1.65MMt. Corpus Christi was the only major facility to post a notable month-on-month decline, dropping 8 percent from December, with Freeport down 7 percent and Cameron down 6 percent. Plaquemines continued to increase output, exporting 2.21MMt at 118 percent capacity utilisation as additional trains enter commissioning.

Beyond the US, several non-US Atlantic producers contributed materially to the basin decrease. Angola LNG output fell 46 percent to 0.27MMt, a loss of 0.23MMt that ranked as the largest single non-US country reduction. Volumes out of Trinidad's Atlantic LNG dropped 17 percent to 0.68MMt. Meanwhile, Algerian LNG exports decreased 24 percent to 0.38MMt, with output from both Skikda and Arzew well below nameplate (Skikda 14 percent, Arzew 17 percent), which is consistent with the ongoing constraint on feedgas availability after pipeline commitments to Southern Europe are met. Elsewhere in Africa, output by Cameroon FLNG dropped 60 percent to 0.06MMt and Senegal's Tortue FLNG eased shipments by 22 percent to 0.18MMt. These were partially offset by Equatorial Guinea's EG LNG, up 36 percent to 0.19MMt. Nigeria eased 1 percent to 1.55MMt, with Bonny Island operating at 84 percent utilisation.

In Europe, Norway's Snøhvit grew exports 31 percent to 0.42MMt whilst Russia's Atlantic basin exports fell 6 percent to 1.99MMt. The composition shifted away from Yamal LNG, where output fell 16 percent to 1.72MMt, while Arctic LNG 2 resumed shipments at 0.20MMt (12 percent utilisation) after a zero-output December. Separately, two cargoes totalling 0.11MMt were re-exported from Arctic LNG 2 Storage at Murmansk via ship-to-ship transfers from the sanctioned terminal's ice-class carriers; these are excluded from the export total as re-exports but are consistent with Novatek continuing to use STS workarounds to circumvent Western sanctions.

LNG Canada, the new Canadian facility, more than doubled its output to 0.63MMt from December's 0.30MMt. The plant has been ramping unevenly since first cargo in August 2025, with utilisation now at 54 percent of its 14 MTPA nameplate.

Middle East exports rose 10.0 percent to 8.55MMt, reversing December's flat performance and returning to levels last seen in January 2025. Ras Laffan drove the move, increasing flows by 12 percent to 6.94MMt, pushing basin utilisation up 9.2 percentage points to 96.3 percent. This aligns with the seasonal pattern of Qatari exports rising during Northern Hemisphere winter when Asian and European demand peaks. Oman LNG eased 5 percent to 1.02MMt (118 percent utilisation, reflecting debottlenecking above nameplate), and Das Island edged up to 0.45MMt. Idku LNG, Egypt's sole active export facility in January (our data for Damietta SEGAS showed no output for the month), rose 75 percent but remains at only 23 percent utilisation — Egypt continues to struggle with feedgas allocation to LNG amid rising domestic gas demand.

Pacific basin exports edged lower by 1.9 percent to 13.51MMt, up 3.8 percent year on year. Utilisation held at 84.5 percent, broadly stable and 2.7 percentage points above January 2025. Australia was the primary source of the decline, falling 0.43MMt to 6.35MMt (-6.3 percent). The decrease was concentrated in a handful of facilities, our data showed: Gorgon LNG shipments fell 14 percent to 1.27MMt, Gladstone's dropped 30 percent to 0.33MMt (only 51 percent utilisation), Ichthys shipments slumped 14 percent to 0.76MMt, and output from Queensland Curtis and Australia Pacific both slipped 7-8 percent. NWS LNG was the notable countertrend, growing exports by 16 percent to 0.96MMt, while Prelude gained 11 percent to 0.20MMt. Notably, Darwin LNG returned to the market from mothballed state and exported 0.06MMt. The decrease in Australian output was spread across multiple facilities rather than concentrated in any single plant, suggesting normal production variability rather than a specific supply disruption.

Malaysian exports were broadly flat at 2.57MMt. Malaysia LNG accounted for 2.34MMt, essentially unchanged from December. PFLNG 1 contributed 0.11MMt from two liftings and PFLNG 2 shipped 0.12MMt from two cargoes to the nearby Pengerang terminal, operating at 96 percent of its 1.5MTPA nameplate.

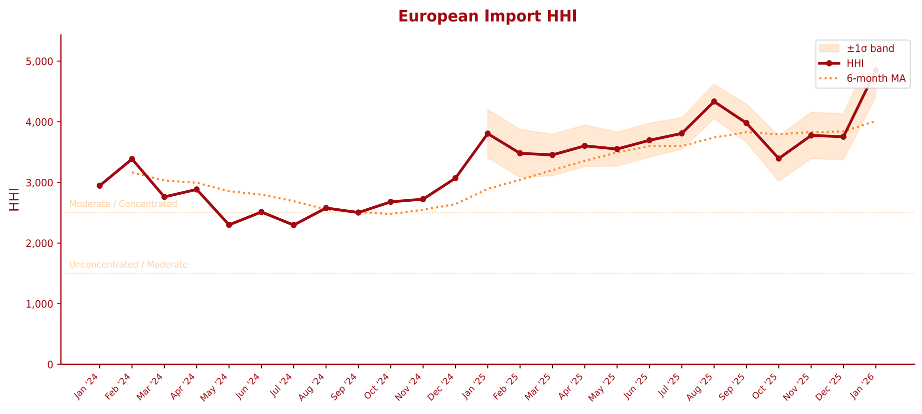
Indonesia edged down 5.6 percent to 1.34MMt, with the headline being Bontang's continued decline: output fell 36 percent to 0.20MMt (20 percent utilisation), consistent with the long-running decline in feedgas from the ageing Mahakam block. Tangguh, by contrast, was stable at 0.95MMt (99 percent utilisation), and Donggi-Senoro held at 0.19MMt. Re-exports from Chinese terminals (Yancheng LNG and Zhejiang LNG) appeared for a second consecutive period, totalling 0.19MMt from three cargoes; these are excluded from the export figures above ♦

Demand

European arrivals hit record concentration at 68 percent US share while Chinese offtake drops 15 percent

European LNG terminal stocks entered January in a relatively comfortable position, with end-of-December fill at 51.3 percent, more than 11 percentage points above the prior year's 40.0 percent. However, the month transformed that surplus into a deficit: a 7.9 percentage point drawdown through January, compared with a net build in January 2025, left stocks at 43.4 percent by month-end, 5.5 percentage points below the year-earlier level. A colder-than-average month sustained firm withdrawal rates throughout, and with Pacific routes uneconomic at prevailing HH levels, US cargoes that would otherwise have sailed east were instead delivered short-haul into this tightening market, producing a record concentration of Atlantic basin arrivals.

British imports drove the largest single-country increase, rising 0.74MMt to 1.99MMt (59 percent), reflecting the urgency of winter restocking. French arrivals grew 0.26MMt to 1.90MMt (16 percent), Spanish intake gained 0.24MMt to 1.42MMt (20 percent), and Canadian terminals took an additional 0.16MMt, lifting the country total to 0.36MMt. German imports continued their structural growth at 0.76MMt (10 percent,



Source: LNG Journal

up 162 percent year on year as FSRU-based regasification capacity matures). Lithuanian volumes rose 47 percent to 0.28MMt. Against this, Italian demand fell 12 percent to 1.17MMt and Dutch intake declined 12 percent to 1.06MMt, while Portuguese imports halved to 0.14MMt. Turkish arrivals held steady at 2.63MMt, having already surged in December.

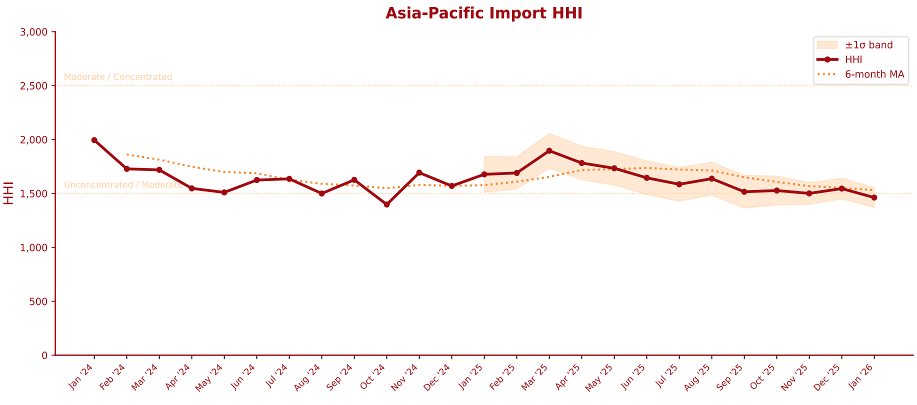
European import HHI leapt to 4,849, an increase of 1,095 points from December's already elevated 3,754, placing the market deep into the "concentrated" zone (above 2,500). US-origin cargoes accounted for 68.0 percent of European LNG arrivals, a level of single-supplier dependence not previously observed. Russian supply held 13.4 percent, followed by Nigerian (3.9 percent), Algerian (3.3 percent), and Qatari volumes (3.2 percent). The surge in British imports, sourced overwhelmingly from the US, contributed directly to the HHI spike: more European volume from a single dominant supplier mechanically raises concentration.

Pacific basin imports fell 8.1 percent to 23.03MMt, essentially flat year on year. Chinese arrivals accounted for the bulk of the reduction, dropping 1.13MMt to 6.21MMt (-15.4 percent). This is consistent with the drop in Atlantic-to-Pacific flows: with fewer US cargoes reaching Asia, Chinese buyers, who had been absorbing a growing share of US spot volumes through 2025, saw a natural reduction in deliveries. Japanese intake eased 4 percent to 5.97MMt and South Korean demand fell 6.5 percent to 4.29MMt, both within normal seasonal variation.

Indian imports were the standout on the upside, rising 0.36MMt to 2.32MMt (18 percent). Indian supply is predominantly contract-driven under Brent-linked pricing structures (see Section 6), so this increase likely reflects a combination of winter peak demand and scheduled contract deliveries rather than spot market dynamics. Singaporean volumes contracted 71 percent to 0.18MMt, likely reflecting an operational disruption or cargo scheduling timing rather than a fundamental demand shift. Bangladeshi offtake fell 30 percent to 0.43MMt, consistent with reported infrastructure constraints limiting regasification throughput during the winter.

Asia-Pacific import HHI declined to 1,462, dipping further below the unconcentrated/moderate threshold of 1,500. The supplier base for Asian imports remains diverse: Australian volumes (26.3 percent), Qatari supply (21.6 percent), Malaysian exports (11.4 percent), US cargoes (6.7 percent), Indonesian output (5.9 percent), and Russian deliveries (5.6 percent) together account for the top six. No single supplier dominates, and the index has been on a gently declining trend since mid-2024.

Global export HHI was steady at 1,481, within the unconcentrated range. US output led at 27.4 percent share, followed by Qatari (17.8 percent), Australian (16.2 percent), Russian (7.8 percent), and Malaysian volumes (6.6 percent). The top three suppliers collectively accounted for 61 percent of global trade, a moderate level of concentration ♦



Source: LNG Journal

Cargo Routing and Arbitrage

Atlantic-to-Pacific volumes collapse 60 percent as SHPGX-HH spread narrows to $2.50/MMBtu

The collapse in Atlantic-to-Pacific flows was the month's most significant routing development. Volumes on this corridor fell from 2.96MMt in December to 1.18MMt in January, a drop of 60 percent and a loss of 4.5 percentage points of total trade share. The arithmetic makes the cause plain: with Henry Hub averaging $7.72/MMBtu and SHPGX at $10.21, the gap of $2.50/MMBtu barely covers the cost of liquefaction alone (Gulf Coast tolling fees typically run $2.25-$3.00/MMBtu), leaving nothing for shipping on a long-haul trans-Pacific voyage. For many contract structures, this meant cargoes were more profitably, or less unprofitably, delivered into Europe or diverted within the Atlantic basin.

The inter-basin flow matrix confirms this rebalancing. Atlantic-to-Atlantic volumes rose from 13.34MMt to 13.87MMt, absorbing a greater share of US output within the basin. Middle East-to-Pacific flows were stable at 6.48MMt, and Pacific-to-Pacific intra-basin trade was steady at 13.23MMt. The routing disruption was concentrated on the single Atlantic-to-Pacific corridor.

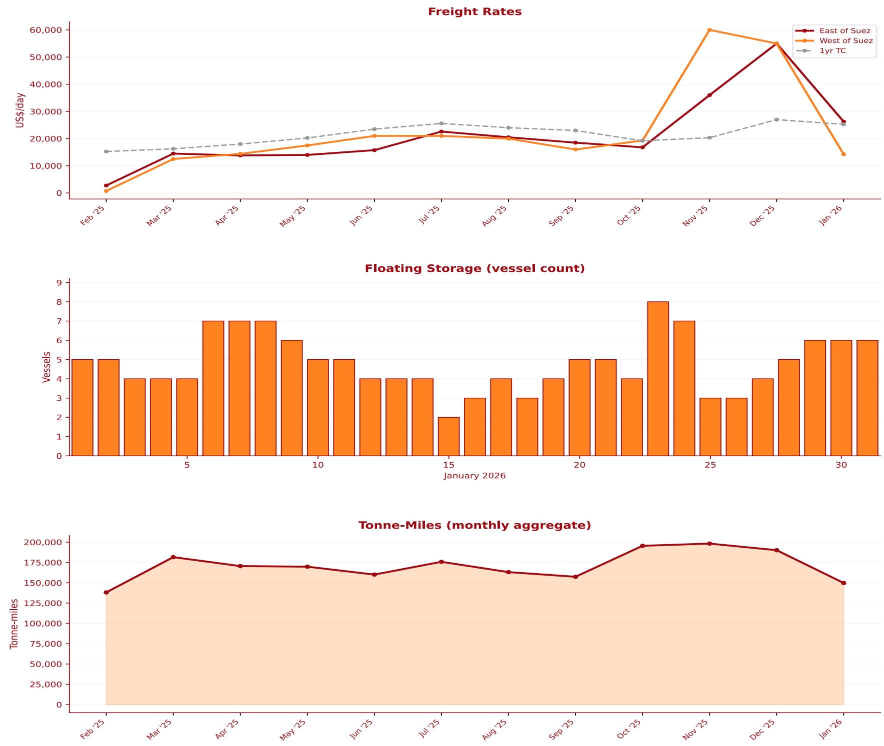
Inter-basin diversions surged from 11 in December to 27 in January, consistent with cargoes being redirected en route as price signals shifted. Intra-basin diversions fell from 194 to 159.

Choke point transits reflected shorter average voyages. Cape of Good Hope transits fell from 45 to 28 and Malacca Strait transits from 77 to 58, both consistent with fewer eastbound long-haul cargoes from the Atlantic. Suez Canal transits dropped from 8 to 5.

Spot freight rates dropped from previous highs reached in November and December. East of Suez fell 52 percent month on month to $26,250/day and West of Suez plunged 74 percent to $14,250/day. The 1-year time charter rate was relatively stable at $25,250/day, down 6.5 percent. The East-West spread widened to $12,000/day in favour of East of Suez, down from the near-parity seen in December. The November-December spike had been driven by a scramble for tonnage as winter demand pulled cargoes in multiple directions simultaneously; with the HH spike now redirecting US cargoes into the Atlantic and reducing long-haul demand, the spot market rapidly loosened.

Floating storage — laden vessels holding cargo at sea rather than delivering, typically a sign of oversupply or speculative positioning — was unremarkable. The peak vessel count reached 8 on 23 January, with an estimated volume of 0.45MMt. The monthly average was 4.8 vessels. The daily profile showed some clustering in the first third of the month (6-8 vessels on days 6-8) and again briefly around day 23, but no sustained build-up.

Aggregate tonne-miles fell 21.2 percent month on month to 149,766. Average distance per cargo fell to 4,014 NM from December's 4,653 NM, consistent with the shift towards shorter-haul Atlantic basin trade. Year on year, tonne-miles were up 50.8 percent, reflecting the structural growth in traded volumes even as the average haul shortened ◆



Source: LNG Journal / Fearnleys / AIS

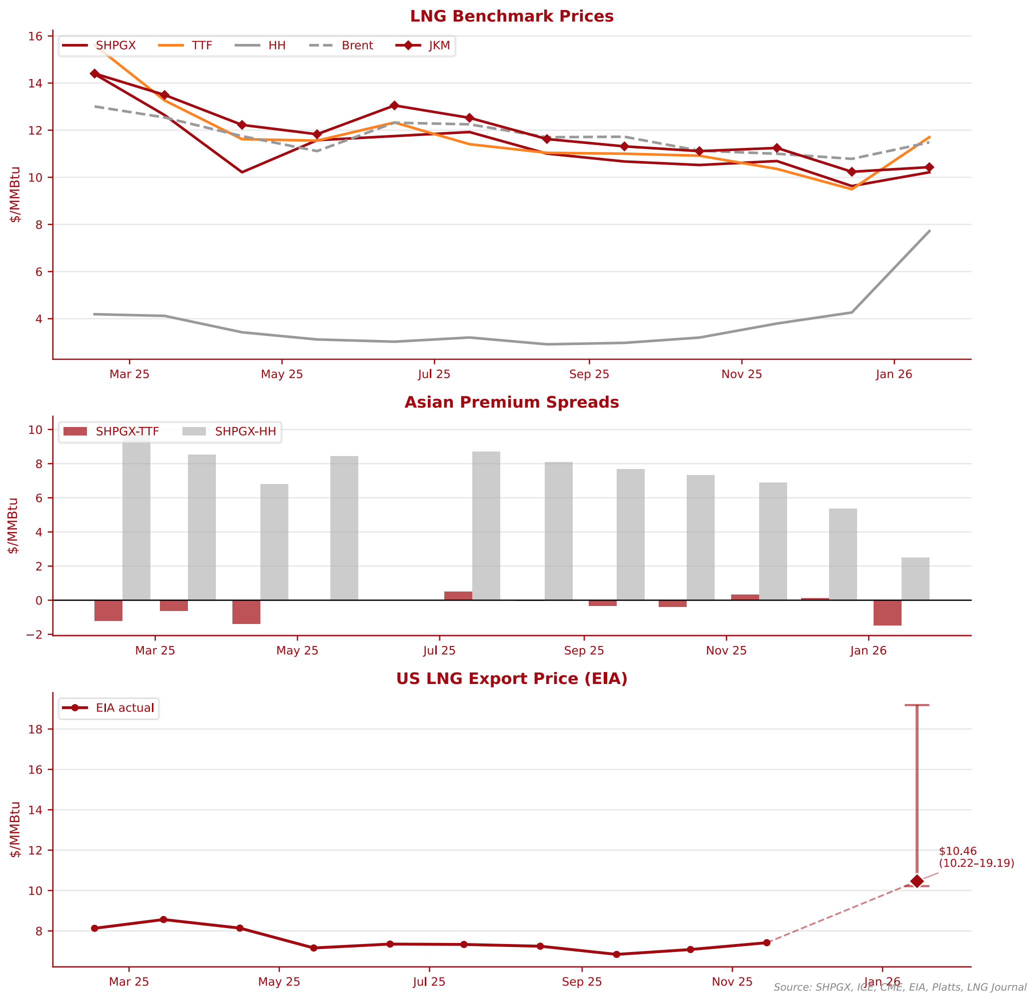
Pricing

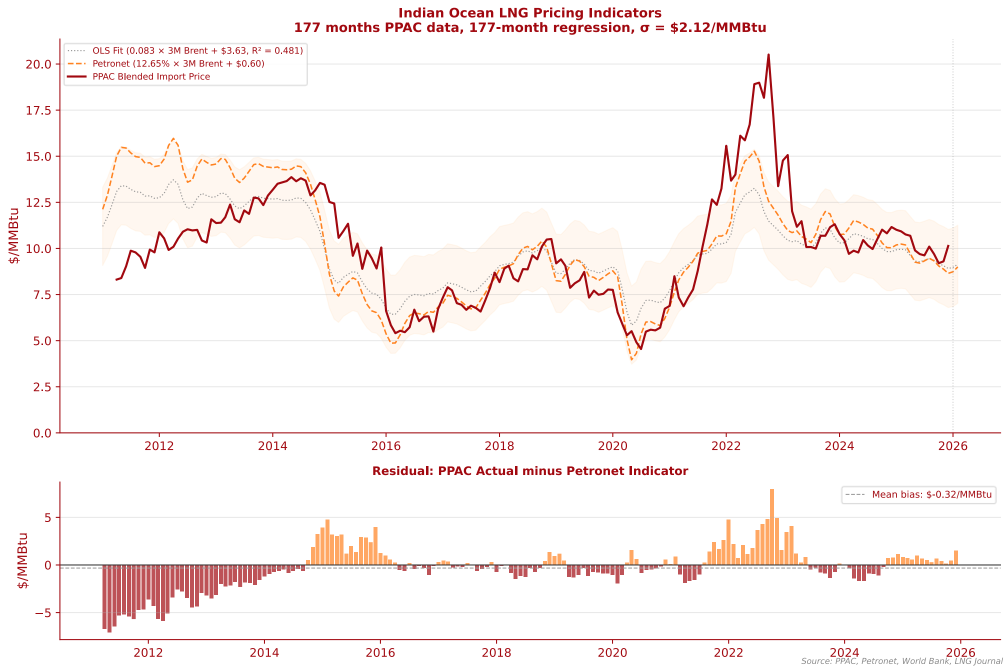
Henry Hub surges 81 percent, compressing US export spreads and pushing SHPGX below TTF

January 2026 saw HH, TTF, SHPGX, and JKM rise in January, but the driving force was Henry Hub's surge toward international price levels, compressing the spreads that underpin US LNG export economics.

Henry Hub averaged $7.72/MMBtu, up $3.45 (81 percent) from December's $4.27. This was the highest monthly HH average since the 2022 energy crisis and the sharpest single-month increase in over a decade. The spike was weather-driven: a sustained cold event across the US Midwest and South-East produced record heating demand and a rapid draw on gas storage, tightening the physical market. HH had traded in a narrow $2.91-$4.27 range from February through December 2025, making January a sharp departure from the range that had prevailed for nearly a year. Year on year, HH was up $3.59 (87 percent), having been at $4.13 in January 2025.

TTF rose 23 percent to $11.70/MMBtu (converted from EUR/MWh at an average EUR/USD rate of 1.17). The primary driver was physical tightness in the European gas market: terminal storage entered the month below the five-year average, and a colder-than-average January sustained firm withdrawal rates, keeping the market bid even as





additional US cargoes arrived. The flow data confirms that European buyers received more US LNG in January, not less, yet TTF still rose, indicating that consumption outpaced the incremental supply. TTF had declined steadily through the second half of 2025, from $15.61 in February to $9.49 in December, so the January recovery to $11.70 returns the benchmark to mid-Q4 levels rather than representing a new high. Year on year, TTF is 20 percent lower, reflecting the structural easing of European gas markets relative to the tighter conditions of early 2025.

SHPGX, the Chinese landed spot LNG price published by the Shanghai Petroleum and Natural Gas Exchange, rose 6.1 percent to $10.21/MMBtu. SHPGX has been on a persistent downtrend since its February 2025 high of $14.38, and the January figure sits close to the trailing 12-month low of $9.63 reached in December. JKM, the Platts-assessed Asian spot benchmark, averaged $10.43/MMBtu for the month, but the monthly figure masks a sharp intra-month repricing: JKM traded at $9.55–9.70 for the first two weeks before jumping to $11.15 on the 16th and holding at $11.2–11.5 for the remainder of the month. The timing aligns with the intensification of the US cold snap and the visible tightening of spot availability in the Pacific basin as Atlantic-to-Pacific flows collapsed. The Asian spot market did register the squeeze — but with a lag and at a fraction of the magnitude seen in HH, and the repricing did not sustain into February, with JKM easing back below $11 in the first half of the month.

The relative calm in SHPGX compared to the step change in JKM likely reflects compositional differences between the two indices: SHPGX captures Chinese landed cargo settlements, which skew towards earlier-month fixtures, while JKM is a forward-assessed marker that responds more quickly to shifting prompt fundamentals.

The broader picture, however, is that the collapse in Atlantic-to-Pacific flows removed US spot cargoes from the Pacific basin pool, tightening availability for buyers in South Korea, Japan, Taiwan, and southeast Asia who would ordinarily compete for that tonnage. In a firm demand environment, this should have bid up Asian spot prices more aggressively. That the repricing was moderate and short-lived suggests Chinese spot appetite was soft enough that the reduced competition for Pacific basin cargoes largely offset the loss of Atlantic supply. China's 15.4 percent import decline reinforces the picture, as does the continued appearance of Chinese re-exports (Yancheng LNG and Zhejiang LNG shipped a combined 0.18MMt in January) — volumes that would not be leaving the country if domestic demand were absorbing all available supply.

The comparison between SHPGX and the European benchmarks nonetheless produced the most notable pricing signal of the month: SHPGX fell $1.49 below TTF, meaning Chinese spot prices were trading below European delivered prices for the first time in several months. The comparison is imperfect (SHPGX is a delivered price inclusive of shipping; TTF is a hub price before regasification costs), but the directional signal is clear: the Atlantic basin offered better netbacks than the Pacific for marginal cargoes in January, consistent with the routing shift described above.

Brent crude was roughly stable month on month at $11.48/MMBtu equivalent ($66.57/bbl). Year on year, however, it is down 16 percent from $79.27/bbl in January 2025.

Indian Ocean contract pricing. To provide visibility into South Asian import costs, which are predominantly Brent-linked rather than spot-driven, we compute a Petronet indicator from the publicly disclosed Petronet-RasGas contract formula (12.65 percent of the trailing 3-month Brent average plus $0.60/MMBtu base charge). In January 2026, this indicator stood at $8.74/MMBtu, based on a 3-month Brent average of $64.31/bbl, placing it $1.48 below SHPGX and $2.96 below TTF. Indian Ocean contract buyers were largely shielded from the January price spike by the lagged and dampened nature of their oil-indexed pricing formulas. The Petronet indicator has been declining steadily from $10.19 in March 2025, tracking the trailing Brent SMA downward, and the January figure represents a modest recovery from December's $8.65 as the January Brent uptick begins to feed into the 3-month average. Separately, India's blended import cost, which includes spot purchases and contracts at varying slopes alongside the dominant oil-indexed volumes, was $10.14/MMBtu as of the most recently available PPAC data (December 2025), running $1.49 above the pure Petronet indicator. This gap has widened since mid-2025, likely driven by spot purchases at premiums above oil-indexed contract levels. India's 18 percent month-on-month import increase to 2.32MMt in January is best understood against this contract pricing backdrop rather than spot market dynamics: with Brent-linked delivery costs well below prevailing spot levels, Indian buyers had every incentive to maximise contract liftings during the winter peak.

The EIA US LNG export price, which runs on a 2–3 month lag, was last published at $7.69/MMBtu for October 2025. To bridge the gap, we estimate the January 2026 US LNG export price at $10.46/MMBtu (volume-weighted median across 49 EIA destination countries), using per-destination trailing prices adjusted for current-month benchmark movements via OLS regression. The interquartile range is wide at $10.22–$19.19/MMBtu, reflecting the bifurcation between HH-linked Americas destinations, which absorbed the domestic gas spike (estimated Atlantic basin average $16.86/MMBtu, driven by Canada at $19.19), and buyers on TTF- or Brent-linked contracts in Asia and the Middle East, who clustered near the economic floor of $10.22/MMBtu (Henry Hub plus a $2.50 tolling cost). That floor represents the minimum cost of producing a US LNG cargo (feedgas plus liquefaction); it binds for the majority of non-Americas destinations in a month when HH spiked above prevailing international benchmarks ♦

Project Pipeline

Mozambique LNG restarts construction, Golden Pass receives cooldown and US Gulf Coast FID wave matures

The global LNG project pipeline continues to build, with significant new capacity under construction or recently sanctioned across multiple geographies. The year 2025 was the second-highest for LNG final investment decisions on record, with approximately 96 bcm/yr (~70MTPA) of new liquefaction capacity sanctioned according to the IEA, and the commissioning profile for 2026–2030 is now substantially clearer than it was six months ago.

Commissioning facilities. Golden Pass LNG in Texas (18.1 MTPA across three trains, QatarEnergy-ExxonMobil) received its cooldown cargo from Ras Laffan in early January and is actively commissioning Train 1, with first LNG expected in Q1–Q2 2026. Trains 2 and 3 are expected to follow at approximately six-month intervals, though the engineering contract for those trains was only recently finalised following the Zachry Holdings bankruptcy in 2024, and the timeline beyond Train 1 carries uncertainty. LNG Canada continues its commissioning ramp at 54 percent of its 14 MTPA nameplate, with output fluctuating significantly from month to month (0.30MMt in December, 0.63MMt in January) as the facility moves through performance testing. Arctic LNG 2 remains heavily constrained at 12 percent utilisation (0.20MMt), with the appearance of a new "Arctic LNG 2 Storage" entry at Murmansk (0.10MMt) suggesting that Novatek continues to employ ship-to-ship transfer workarounds to move LNG from ice-class carriers to conventional tonnage under ongoing Western sanctions.

Qatar North Field expansion. The first train of the North Field East (NFE) expansion, originally targeting end-2025, has slipped progressively: QatarEnergy indicated mid-2026 at the Qatar Economic Forum in May 2025, then Q3–Q4 2026 at ADIPEC in November, with recent reports suggesting the timeline may extend into Q4 2026 or early 2027. NFE comprises four 8 MTPA trains (32 MTPA total), with TotalEnergies indicating all four should be producing by mid-2028. North Field South (16 MTPA, two trains) and North Field West (16 MTPA, two trains) are in engineering and earlier development respectively, with NFS/NFW completion extending the total expansion to 64 MTPA by the end of the decade. Even allowing for further slippage, NFE alone represents the single largest tranche of new capacity approaching commissioning anywhere in the world.

US Gulf Coast build-out. Beyond Golden Pass, the major US projects under construction are Rio Grande LNG, Port Arthur LNG, CP2 LNG, Corpus Christi Midscale, and Woodside Louisiana LNG.

Rio Grande LNG (NextDecade-TotalEnergies) reached FID on Train 4 in September 2025 and Train 5 in October 2025, bringing total capacity under construction to approximately 30 MTPA across five trains of roughly 6 MTPA each. Phase 1 (Trains 1-3) is targeting first LNG in 2027, with Train 4 targeting the second half of 2030 and Train 5 the first half of 2031. Trains 6-8 (~18 MTPA) are in development and entering the FERC permitting process, which would bring the full site to approximately 48 MTPA.

Port Arthur LNG has Phase 1 under construction with Trains 1 and 2 targeting 2027 and 2028; Phase 2 reached FID in September 2025, adding Trains 3 and 4 for a total facility capacity of 26 MTPA with commercial operations in 2030-2031. CP2 LNG (Phase 1) reached FID in July 2025 with $15.1 billion in project financing, 14.4 MTPA nameplate with ~20 MTPA peak capacity, first LNG targeting 2027; Phase 2 FID is targeting mid-2026 and would bring the facility to approximately 28 MTPA peak capacity.

Cheniere's Corpus Christi continues to expand in stages: four of the seven Stage 3 midscale trains reached substantial completion during 2025 (the remaining three are expected in 2026), and the company reached FID in June 2025 on Midscale Trains 8 and 9, adding a further 3 MTPA of liquefaction capacity plus debottlenecking that will bring the full terminal to over 30 MTPA later this decade. Cheniere has also filed with FERC for a Stage 4 expansion (24 MTPA across four large-scale trains), which would grow the Corpus Christi site alone to over 50 MTPA, though this remains at the pre-FID stage.

Woodside Louisiana LNG (formerly Driftwood) reached FID in April 2025 on a 16.5 MTPA three-train foundation phase, with construction approximately 25 percent complete and first LNG targeting 2029; the facility is fully permitted for 27.6 MTPA but only Phase 1 is sanctioned.

Mozambique restart. TotalEnergies and the government of Mozambique formally restarted construction of the 13 MTPA Mozambique LNG project at Afungi on 29 January 2026, lifting the force majeure declared in April 2021 following insurgent attacks in Cabo Delgado province. The project is approximately 40 percent complete, having continued engineering and equipment procurement during the suspension, and is targeting first LNG in 2029. Incremental costs from the nearly five-year delay are estimated at $4.5 billion above the original $20 billion budget. This is one of the most significant supply-side developments of the month: a 13 MTPA project returning to active construction after years of uncertainty. ExxonMobil's adjacent Rovuma LNG is progressing through FEED.

Other FIDs and developments. Argentina LNG has evolved into a multi-phase development centred on the Gulf of San Matías, all using FLNG technology to monetise Vaca Muerta shale gas. Phase 1 (the "Southern Energy" project, a five-partner consortium led by Pan American Energy alongside YPF, Pampa Energía, Harbour Energy, and Golar LNG) reached FID in May 2025 and will deploy two of Golar's FLNG vessels: the Hilli Episeyo (2.45 MTPA, targeting production from late 2027) and the newbuild MK II (3.5 MTPA, targeting late 2028), for a combined 5.95 MTPA. Phase 2, originally a 12 MTPA Shell-YPF venture, was halved to approximately 6 MTPA after Shell exited in December 2025; YPF is seeking a replacement partner. The largest planned phase (12 MTPA across two new 6 MTPA FLNG units) is being advanced by YPF, Eni, and ADNOC's XRG, which signed a binding joint development agreement in February 2026 and are targeting FID in the second half of 2026 with exports in 2030-2031. If all phases proceed, Argentina could ultimately reach 24 MTPA of export capacity, though the phased approach, evolving partnership structures, and the scale of required pipeline infrastructure from Vaca Muerta to the coast introduce significant execution uncertainty.

Coral North FLNG (3.4 MTPA, Mozambique, Eni-led) completed its hull launch and remains on track for 2028. Ust Luga LNG in Russia (19.6 MTPA) is nominally under construction but remains pre-FID and faces significant uncertainty under the current sanctions environment.

FEED and pre-FID pipeline. Mexico has four projects at FEED stage totalling 44 MTPA (Saguaro Energía, AMIGO FLNG, Gato Negro Manzanillo, and Salina Cruz), all targeting Pacific coast sites that would serve Asian markets without Panama Canal transit constraints. Papua LNG (6.6 MTPA, TotalEnergies-ExxonMobil) and Canada's Ksi Lisims FLNG (12.0 MTPA) are targeting FID decisions in 2025–2026. Canada's Cedar FLNG (3.3 MTPA, targeting 2028) and Woodfibre LNG (2.1 MTPA, targeting 2028) are under construction, adding further Pacific basin supply. The UAE's Ruwais LNG (9.6 MTPA, FID 2024) adds Middle Eastern capacity.

Import side. Notable construction-stage developments include Germany's Brunsbüttel onshore terminal (7.35 MTPA, targeting 2027), South Korea's KOGAS Dangjin terminal (13.7 MTPA, targeting 2027), and India's Jaigarh terminal (14.0 MTPA, targeting 2026). India's Gopalpur terminal (5.0 MTPA) and Thailand's Map Ta Phut Terminal 3 (10.8 MTPA) both reached FID in 2025 ♦