Gas Market Outlook 2025

1. Executive Summary

As the global gas market enters 2025, it does so at a pivotal moment shaped by a complex interplay of geopolitical tension, supply-demand imbalances, and evolving consumption patterns. Although the expansion of LNG supply capacity—particularly in North America—had raised earlier expectations of a market surplus, such projections have not materialized due to persistent macroeconomic challenges, infrastructure bottlenecks, and heightened energy security concerns.

Crises in the Middle East, ongoing sanctions on Russia, and shifting U.S. energy policies under the Trump 2.0 administration are collectively altering global trade flows, with significant implications for both producers and import-reliant economies. This brief outlines the main trends driving the global gas market in 2025, with particular focus on how they affect countries like Indonesia. It further offers guidance on adaptive strategies in energy procurement and policy to help navigate these evolving dynamics.

2. Key Trends in 2025

2.1 Supply-Demand Balance and Pricing

LNG Supply Surge

The year 2025 marks a major milestone in the expansion of global LNG supply. Several large-scale export facilities—such as Plaquemines and Corpus Christi in the U.S., as well as LNG Canada—have come online, contributing significantly to global capacity. Overall, LNG supply is projected to increase by approximately 5%, translating to an additional 27 billion cubic meters (bcm) of gas. This marks a substantial injection of new volume into the market and reflects the culmination of multi-year investment cycles aimed at addressing future demand growth.

Tight Market Conditions

Despite the increase in supply, market conditions remain tight due to several structural and geopolitical constraints. Russia's sharp reduction in pipeline gas exports—particularly to Europe—continues to strain available supply. Meanwhile, congestion in strategic maritime routes like the Panama Canal and Suez Canal has disrupted logistics and led to delays and higher transportation costs.

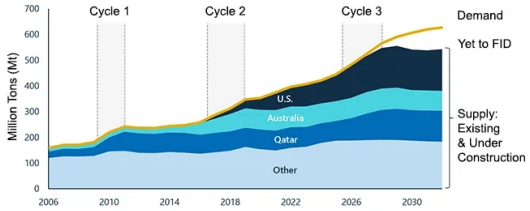

Figure 1. Natural Gas Intel, european forecast on LNG Supply-Demand Cycles - Cheniere Energy Inc (Cocklin, 2024)

The global LNG market is approaching a period of significant imbalance, as a surge in supply is expected between 2026 and 2028, while demand growth, though ongoing, is not keeping pace, according to industry experts. Jason Feer of Poten & Partners highlights the difficulty of managing a glut in LNG, noting that the fuel cannot be stored indefinitely, while Wood Mackenzie's Massimo Di Odoardo emphasizes the uncertainty around how long the oversupply may persist into the 2030s. Historically cyclical, the LNG market has recently faced volatile pricing and tight supply due to global energy disruptions. Looking ahead, Shell projects a 50% increase in global LNG demand by 2040, driven by industrial coal-to-gas transitions in China and growing consumption across South and Southeast Asia. However, the International Energy Agency (IEA) forecasts global gas demand will peak by 2030 and then plateau, with a gradual decline toward 2050, as renewables increasingly erode gas' share in the energy mix, though the pace of decline remains uncertain.

Adding to this is growing policy uncertainty in key exporting countries, which has eroded investor confidence and limited supply chain flexibility. The net effect is a market that remains constrained, with limited surplus to accommodate unexpected shocks.

Volatility in Prices

Prices in the Asian spot LNG market are expected to remain volatile, reflecting both the tight market fundamentals and the geopolitical uncertainty. For 2025, the average price is forecasted to hover around USD 13.5 per million British thermal units (MMBTU), marking an increase from under USD 12/MMBTU in 2024. This upward pressure in prices indicates that, despite the new supply additions, the market has not shifted into oversupply territory.

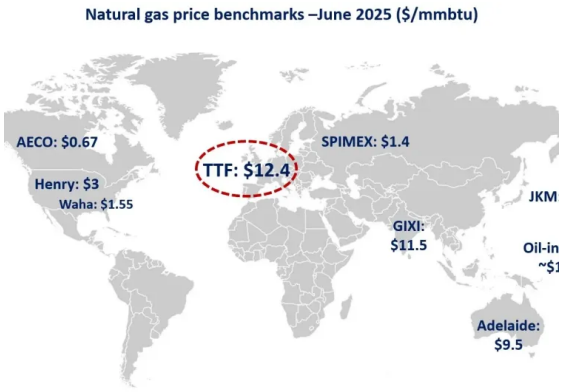

Figure 2. All eyes in LNG pricing benchmark – strong volatility across Asia and European market through June, 2025 (GLNGH, 2025)

The Middle East crisis in June triggered sharp price volatility across Asian and European gas markets, initially driving up prices on fear of potential supply disruptions. In Europe, TTF prices surged to a four-month high, rising 14% year-on-year to an average of $12.4/mmbtu—peaking near $14/mmbtu at the height of the Israel-Iran conflict due to concerns over potential LNG flow disruptions through the Strait of Hormuz—before falling 20% following a ceasefire, settling just above $11/mmbtu. Despite the price drop, the European market remains tight due to reduced Russian and Norwegian pipeline supplies and stronger storage injections, while LNG imports have grown by 40% year-on-year. In Asia, JKM prices mirrored the trend, increasing 6% to an average of $13/mmbtu, largely influenced by geopolitical tensions, though regional demand remains weak with China and India posting year-on-

year LNG import declines of 6% and 16% respectively. In the U.S., Henry Hub prices rose nearly 20% year-on-year to an average of $3/mmbtu, supported by stronger storage injections and increased exports, marking a recovery from last year's historically low levels, while domestic gas production grew 4% year-on-year and remains near record highs.

Instead, external factors such as shipping disruptions and competitive bidding among buyers continue to drive price fluctuations.

2.2 Geopolitical Tensions

Middle East and Red Sea Disruptions

Rising instability in the Middle East and along the Red Sea shipping corridor has led to significant rerouting of LNG carriers, increasing travel distances and, consequently, shipping costs. The presence of military threats and potential blockades in these areas has also raised the insurance premiums and logistical risks associated with these routes. These disruptions not only raise the cost of delivery for end-users but also reduce the effective availability of shipping capacity in the global LNG fleet. The disruption was really unexpected for a certain market in Asia and European countries. In the figure 2 above the benchmark is rising through the political tension in the regions.

U.S. LNG Policy Shifts

Under the Trump 2.0 administration, U.S. energy policy is expected to pivot, potentially leading to the removal of existing restrictions on LNG export permits. If enacted, such a shift could enhance the volume of U.S. LNG entering global markets, reinforcing the country's position as a leading exporter. However, the policy reversal also introduces new uncertainties, especially regarding the long-term regulatory environment, which may affect investment timelines and global contracting behavior.

Russia's Diminished Role

Russia's position as a dominant pipeline gas supplier has been significantly weakened. In the wake of sanctions and geopolitical fallout, Russian pipeline exports to Europe have declined sharply. This has forced European countries to seek alternative sources, particularly through LNG imports. As a result, global LNG demand has been structurally altered, with long-term implications for supply contracts, pricing benchmarks, and geopolitical alignments in the energy trade.

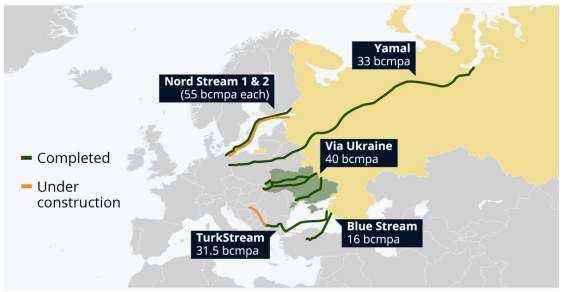

Figure 3. Major Russian-European natural gas pipelines and theoretical capacities (in billion cubic meters per annum)

(JPMorgan via The Economist, 2022)

Russian natural gas accounts for roughly a third of Europe's total gas consumption, primarily delivered through major pipelines such as Yamal (via Belarus and Poland, 33 bcm/year), Nord Stream (via the Baltic Sea, 55 bcm/year), and Ukrainian transit routes (40 bcm/year), making gas a crucial component of the continent's energy mix and raising concerns over supply stability amid tensions between Russia and Western powers. Key economies like Germany, Italy, and Poland rely on Russia for over 40% of their gas needs, with smaller Eastern European and Balkan states even more dependent. The controversial Nord Stream 2 pipeline, designed to double the capacity of Russian gas exports to Germany, had already sparked criticism over increased energy dependency before the Ukraine crisis. Despite this, experts suggest Europe could replace up to two-thirds of Russian gas through alternative pipeline supplies from Norway, the UK, and North Africa, along with expanded LNG imports and regasification capacity, including potential Qatari supplies. Meanwhile, Russia's military buildup near Ukraine continues to raise alarms, prompting U.S. troop deployments to bolster NATO presence in Germany, Poland, and Romania, amid escalating geopolitical uncertainty.

2.3 Regional Demand Dynamics

Europe

Europe is anticipated to be the primary driver of global LNG demand growth in 2025. The continent's strategic goal of diversifying energy sources—away from Russian pipeline gas—has led to expanded investment in LNG import infrastructure, including new terminals and storage facilities. European buyers are also actively engaging in long-term supply agreements to secure volumes amid growing global competition.

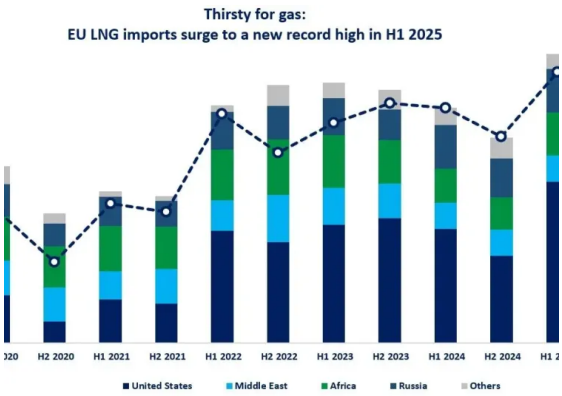

Figure 4. European LNG imports surge by a straggering 40% (GLNGH, 2025)

EU LNG imports are expected to remain strong in the second half of 2025, driven by continued storage refill needs, reduced Russian and Norwegian pipeline flows, and potentially higher power sector demand due to summer heat and low renewable output. With gas storage levels still nearly 20 bcm below last year and below the five-year average, the region must maintain high injection rates ahead of winter. The halt of Russian gas transit via Ukraine and ongoing Norwegian maintenance further tighten supply, leaving LNG as the primary balancing source. Meanwhile, the U.S. continues to dominate the EU's incremental LNG supply—accounting for nearly 90% of the increase—led by Plaquemines LNG, which alone met almost 30% of incremental demand.

However, the outlook is clouded by intensifying global competition, especially as signs emerge of China's gas demand recovery, which could draw more LNG cargoes to Asia and drive up prices. As a result, while European LNG demand will likely remain elevated, market tightness and pricing volatility could intensify through H2 2025.

Asia

In contrast, Asia's LNG demand growth is projected to slow in 2025, reaching approximately 2%, down from 5.5% in 2024. This deceleration reflects a combination of economic headwinds, ongoing energy transitions toward renewables, and sensitivity to higher LNG prices. Countries with limited fiscal space may find it increasingly difficult to maintain high levels of spot market purchases, especially in a volatile price environment.

Indonesia & Emerging Asia

Import-reliant countries such as Indonesia and other emerging Asian economies face a more challenging landscape. They must now compete with wealthier economies for limited spot cargoes while also contending with domestic infrastructure constraints. Many lack sufficient regasification capacity or robust distribution networks, which limits their ability to quickly scale up LNG imports.

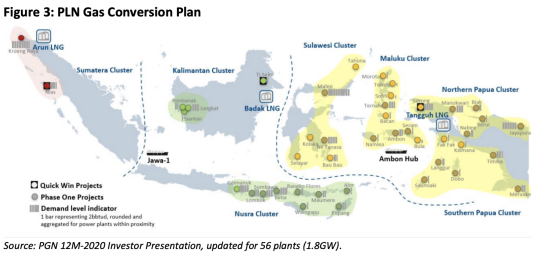

Figure 5. PLN plan on gas conversion in Indonesia (Adiguna, 2021)

Over the years, small-scale LNG (ssLNG) initiatives have been promoted by various stakeholders, but a consistent focus on establishing a stable value chain has been lacking. Initially led by PLN in developing the gas conversion supply chain, the utility has since reverted to its traditional role as an off-taker, now emphasizing affordability, which shifts the commercial and financial burden onto PGN to reduce supply costs, effectively transferring nearly all project risk to PGN. The current plan, revised multiple times, aims to convert 52 power plants

within two years, organized into seven distribution clusters supported by three LNG hubs—Arun, an FSRU near Java, and a planned hub in Ambon.

Three "Quick Win" projects in Sorong, Tanjung Selor, and Nias are prioritized, with Sorong already successfully gasified due to its proximity (3.7 km) to a gas producer, a logistical advantage most other sites lack, leaving ssLNG as the only viable delivery method. The conversion effort faces significant geographic and economic challenges, especially as nearly half of the target plants are only 3–4 years old, over 20 are not yet operational, and 17 are designed for just 10 MW capacity. Additionally, over half require less than 2 BBTUD of gas, while even larger plants (40–165 MW) have relatively low forecasted gas demand (2–14 BBTUD), posing scale-efficiency issues for the gas supply chain. Most plants are newer gas-powered (PLTMG) or dual-fuel (PLTD Dual Fuel) units designed for higher fuel efficiency and flexibility, a shift reflected in the Power Generation Cost (BPP) estimates for PLTMG facilities like the Sorong plant, operated by Indonesia Power, which currently runs on a blend of HSD and biodiesel.

Furthermore, high price volatility introduces risks to budget planning and energy affordability, underscoring the need for more strategic procurement approaches, such as securing medium- or long-term contracts and diversifying supply sources.

3. Implications for Indonesia

3.1 Domestic Policy Adjustments

Revised Gas Volume Targets

Indonesia has revised its national gas demand forecast downward—from an earlier target of 1,038 billion British thermal units per day (BBTUD) to 917 BBTUD. This revision reflects not only macroeconomic adjustment but also practical limitations in domestic infrastructure and procurement capability. The lower target suggests a more cautious approach to consumption planning, like fluctuating market access, and uncertainties in LNG availability.

LNG Import Policy Constraints

As an LNG-importing country, Indonesia faces increasing pressure to adjust its import strategies. Existing policy constraints—including import regulations and capacity ceilings—need to be reassessed to align with current market realities. In the absence of sufficient domestic capacity to absorb and regasify imported LNG, Indonesia may need to pursue international negotiations for supply security or joint procurement frameworks with regional partners. Addressing these constraints will be important for maintaining reliability in energy supply, especially as competition for cargoes intensifies.

Price Regulation Pressure

Indonesia continues to keep the Domestic Gas Price Regulation (Harga Gas Bumi Tertentu, or HGBT), which caps gas prices for specific sectors. While this policy aims to support downstream industries and manage inflationary pressures, it creates tension within the procurement ecosystem.

To accelerate economic growth and enhance the competitiveness of national industries through the utilization of natural gas, as well as to implement the provisions of Articles 3, 5, 7(2), and 8 of Presidential Regulation No. 40 of 2016 on the Determination of Natural Gas Prices, the Minister of Energy and Mineral Resources (ESDM), Arifin Tasrif, issued Ministerial Regulation No. 8 of 2020 concerning the Procedures for Determining Users and Certain Natural Gas Prices in the Industrial Sector. This regulation sets a maximum natural gas price of US$6 per mmbtu at the plant gate for designated industrial users, including fertilizer, petrochemical, oleochemical, steel, ceramic, glass, and rubber glove industries, with pricing determined based on field economics, domestic and international gas prices, consumer purchasing power, and added value from domestic utilization. Price adjustments are made through revisions in gas purchase prices from PSC contractors and/or gas transmission tariffs, which include costs related to liquefaction, compression, pipeline transport, LNG and CNG delivery, storage, regasification, trading, and a reasonable margin, with input from SKK Migas, BPMA, or BPH Migas. Industrial gas

users must submit applications to the Ministry of Industry, which then provides recommendations to the ESDM Ministry after administrative, technical, and economic evaluation. The ESDM Minister, upon review, may coordinate with the Minister of Finance if adjustments impact state revenue, and will determine eligible users, gas volumes, and adjusted prices accordingly. These adjustments reduce the government's revenue share from the production sharing contract (PSC), without affecting the PSC contractor's portion, with reductions capped at the state's revenue for the current year. All administrative processes, including gas sales agreements and transmission tariff documentation, must be completed within one month of issuance. Gas distributors serving eligible users may receive proportional incentives as determined by the ESDM Minister, who may also assign SOEs or their affiliates in the gas sector to deliver supply. Oversight of implementation is conducted by the Directorate General of Oil and Gas, SKK Migas, BPMA, and BPH Migas, within their respective authorities. The regulation maintains the US$6 per mmbtu price cap upon enforcement and revokes ESDM Regulations No. 16 and 40 of 2016. It was enacted on April 2, 2020, and officially promulgated in Jakarta on April 6, 2020.

Traders and importers face narrowing margins, especially in a context of rising international prices and tighter global supply. The persistence of this regulatory approach without reform could compromise the financial viability of import operations and disincentivize market participation.

3.2 Infrastructure Bottlenecks

Shipping Access

Indonesia's reliance on specific maritime routes has exposed it to geopolitical and logistical vulnerabilities. Given ongoing disruptions in global shipping channels—such as the Suez and Panama canals—there is an urgent need to diversify shipping routes and secure alternative delivery pathways. Enhancing port connectivity and investing in maritime resilience can help mitigate the risks to ensure a more robust LNG supply chain.

Cancelled Projects

The cancellation of planned infrastructure projects—whether regasification terminals, storage facilities, or pipelines—has revealed the fragility of Indonesia's gas infrastructure strategy. Overreliance on a small number of suppliers or delivery points increases exposure to external shocks. These project delays or cancellations signal the need for better project governance, risk diversification, and long-term infrastructure planning to support energy security.

3.3 Energy Transition and Methane Regulation

Methane Emission Standards

As global regulatory regimes around methane tighten, Indonesian gas exporters will need to prepare for compliance with international standards. Methane emissions are a focal point of environmental policy, and importing countries are increasingly demanding transparent reporting and mitigation efforts. Indonesian producers must begin aligning with these frameworks to maintain access to key markets and preserve export competitiveness. Failure to do so may result in reputational risks, tariffs, or outright exclusion from environmentally stringent jurisdictions.

4. Policy Recommendations

1. **Diversify LNG Sourcing**
   Indonesia should accelerate efforts to broaden its LNG supply base through strategic negotiations with new partners and active engagement in regional platforms. Advocating for strategic reserves at the ASEAN level could also bolster collective energy security and reduce exposure to price shocks and supply disruptions.

2. **Enhance Strategic Storage**
   Expanding national buffer stocks for both LNG and pipeline gas will provide critical insurance against supply interruptions. Strategic storage can help stabilize domestic prices, smooth procurement

cycles, and enable more flexible responses to market volatility.

3. **Accelerate Infrastructure Investment**
The government should prioritize infrastructure projects with high strategic value—particularly those that expand regasification capacity and extend pipeline networks into industrial centers. Accelerated completion of these assets will help address current bottlenecks and lay the foundation for long-term energy resilience.

4. **Strengthen ESG Compliance**
Indonesia should develop voluntary emissions reduction frameworks for the gas sector, particularly focused on methane. A potential model is Japan's CLEAN initiative, which emphasizes collaborative decarbonization, monitoring, and transparency. Embracing such standards can enhance Indonesia's environmental credentials and market access.

5. **Integrate Energy Security into Transition Plans**
As Indonesia advances its energy transition agenda, low-emission gaseous fuels—such as blue hydrogen and biomethane—should be integrated as part of the long-term mix. Doing so enables the dual pursuit of energy security and decarbonization, particularly in sectors that are difficult to electrify.

5. Conclusion

The global gas market in 2025 highlights a paradox: even amid supply expansion, energy security remains precarious. For Indonesia, this underscores the necessity of proactive and adaptive policymaking. Diversifying LNG sources, deepening regional cooperation, and accelerating infrastructure development must form the pillars of its response. Beyond market dynamics, the evolving regulatory and environmental landscape demands that Indonesia embed energy security within its broader energy transition strategy—ensuring that the country remains resilient, competitive, and compliant in a rapidly shifting global energy system.

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