ERIA Research Project Report FY2025, No. 41

The Role of LNG and Natural Gas in and Beyond Asia's Energy Transition

Economic Research Institute for East Asia (ERIA) and

The Institute of Energy Economics, Japan (IEEJ)

The Role of LNG and Natural Gas in and Beyond Asia's Energy Transition

ERIA Research Project Report FY2025 No.41

Published in January 2026.

Preface

During the past turbulent years, especially since the Russian invasion of Ukraine in 2022, the world again is reminded that liquefied natural gas (LNG) is the most versatile energy source to respond to people's energy needs. At the same time, the industry is observing growing awareness of the upcoming energy transition. The Association of Southeast Asian Nations (ASEAN) region saw increased LNG imports, with new importers joining the LNG market in 2023. In the 2023 study conducted by the Economic Research Institute for ASEAN and East Asia (ERIA), titled 'Different Impacts of LNG Market Shifts on ASEAN,' the following policy recommendations were presented:

1. Clearly define an important role of LNG and natural gas in energy security and energy transition
2. Secure sufficient long-term supply sources
3. Enhance purchasing power
4. Improve contract terms and conditions

This study on 'The Role of LNG and Natural Gas Towards and Beyond the Energy Transition in Asia', investigates the macro demand and supply structure for LNG and natural gas, its impact on the energy mix in Asian countries, and the trend of low carbon emissions including methane abatement measures in the LNG and natural gas value chain together with the necessity of upstream investment to ensure an ample and stable supply of LNG and natural gas to Asia. The study includes an analysis of the United States' new LNG and natural gas policy and its impact on the Asian LNG market as well.

The authors hope this study will provide new insights for the role of LNG and natural gas in addressing the energy trilemma, taking into account geological influences and economic security perspectives in the whole Asian region.

The Institute of Energy Economics, Japan

Acknowledgements

This study was undertaken based on close discussions with LNG specialists and industry officials in ASEAN, Japan, and the United States. The authors would like to thank all the participants in the series of LNG meetings including the roundtable on 6 October 2024 at LNG PCC in Hiroshima, the workshop on 8 January 2025 in Washington, DC; the meeting on 11 March 2025 at Japan's reception in Houston; the roundtable on 20 June 2025 at LNG PCC in Tokyo; and the online workshop on 14 May 2025.

The presentations or remarks at the above five events – from the region's industry players, government authorities, and stakeholders from other areas that are also active in Southeast Asia and the United States – along with the ensuing discussions were useful and inspiring in developing future strategies and policy measures to support development activities.

The authors would also like to express sincere appreciation to Lucian Puglirearesi, President of the Energy Policy Research Foundation, Inc. and his team; as well as Glen Sweetnam, Senior Vice President of the Asia Pacific Energy Research Centre and researchers in his team, for their kind and generous support for this study, without which this report would not have been possible. All errors and mistakes are the authors' responsibility.

Yusuke Hidaka

Leader of the Working Group

Table of Contents

List of Project Members

Leader	Yusuke Hidaka	Senior Fellow, The Institute of Energy Economics, Japan (IEEJ)
Sub-leader	Hiroshi Hashimoto	Senior Fellow, IEEJ
Sub-leader	Takafumi Yanagisawa	Executive Analyst, Manager, Gas Group, IEEJ
Members	Toshiyuki Sakamoto	Board Member, Director, Climate Change and Energy Efficiency Unit, IEEJ
	Takahiko Tagami	Executive Researcher, Manager of Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ
	Junko Ogawa	Executive Economist, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ
	Satoshi Kihara	Senior Researcher, IEEJ

List of Figures

List of Tables

List of Abbreviations and Acronyms

ASEAN	Association of Southeast Asian Nations
AUSEA	Airborne Ultralight Spectrometer for Environmental Applications
Bcm	billion cubic metres
Bcf/d	billion cubic feet per day
Bcm/y	billion cubic metres per year
CCS	carbon capture and storage
CH_4	methane
CLEAN	Coalition for LNG Emission Abatement toward Net-zero
CO_2	carbon dioxide
COP	Conference of the Parties to the United Nations Framework Convention on Climate Change
CY	calendar year
DES	delivered ex-ship
DOE	Department of Energy
EDF	Environmental Defense Fund
EGAT	Electricity Generating Authority of Thailand
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRINC	Energy Policy Research Foundation, Inc.
ERIA	Economic Research Institute for ASEAN and East Aia
EU	European Union
FID	final investment decision
FLNG	floating LNG
FOB	free on board
FSRU	floating storage and regasification unit
FSU	floating storage unit

FTA	free trade agreement
GHG	greenhouse gas
GIIGNL	International Group of Liquefied Natural Gas Importers
GMP	Global Methane Pledge
GW	gigawatt
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IMEO	International Methane Emissions Observatory
IPCC	Intergovernmental Panel on Climate Change
JOGMEC	Japan Organization for Metals and Energy Security
Lao PDR	Lao People's Democratic Republic
LDAR	leak detection and repair
LNG	liquefied natural gas
MBtu	million British thermal units
MOU	memorandum of understanding
Mscf/d	million standard cubic feet per day
Mt	million tonnes
Mtoe	million tonnes of oil equivalent
Mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt-hour
N_2O	nitrous oxide
OGCI	Oil and Gas Climate Initiative
OGMP 2.0	Oil and Gas Methane Partnership 2.0
PDP	Power Development Plan (Viet Nam)
PGC	Potential Gas Committee
PJ	petajoule
PTT	PTT Public Company Limited, Thailand
Tcf	trillion cubic feet

TTF	Title Transfer Facility
UN	United Nations
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
US	United States

Introduction

The global liquefied natural gas (LNG) and natural gas industry experienced a very turbulent period from 2020 to the beginning of 2023 due to the novel coronavirus (COVID-19) pandemic and its impact on the global economy. Then, the developments were followed by extremely high prices in the period after the Russian invasion of Ukraine in 2022. The global market has calmed since the beginning of 2023, due to reduced gas demand in matured markets in the northern hemisphere and steady development in producing countries, as well as stable operations of LNG production plants around the world without unexpected operational troubles. Such volatility has caused harm to the healthy development of the LNG market in the Association of Southeast Asian Nations (ASEAN) region. By possibly introducing volatility preventative measures and with affordable LNG supply, more stable and healthy development of the regional LNG market could be possible.

During the past turbulent years, the world was again reminded that LNG is the most versatile energy source to respond to people's energy needs. At the same time, the industry is observing growing awareness of the upcoming energy transition. Industry and governments will have to find ways to pursue harmonised goals of economic prosperity and energy transition with cleaner energy sources.

Since the establishment of the Economic Research Institute of ASEAN and East Asia (ERIA) in 2007, energy security in ASEAN and East Asia has always been one of the core policy research areas in which natural gas and LNG have played a significant role. LNG has been one of the most important focal points of ERIA's research activities in the last several years, as it is one of the region's vital products and energy sources.

In support of the initiatives on expanding Asian LNG markets, the Institute of Energy Economics, Japan (IEEJ) has undertaken a series of workshops, research, and policy assessments since 2017.

The demand for natural gas in ASEAN countries is expected to grow faster than the total energy requirement in the region. In parallel with the expansion of renewable energy, the share of natural gas in the energy mix in ASEAN is expected to expand from 19% in 2022 to 28% in 2050, according to the *IEEJ Outlook 2025* published in October 2024.

With modest domestic production growth in ASEAN, it is clear that ASEAN needs stable investment in upstream and infrastructure of natural gas and LNG – receiving terminals, pipelines, and gas-fired power generation facilities – as well as LNG

supply sources from within and outside the region. Both domestic gas production and LNG imports should be even more important in the region in the future.

Natural gas and LNG have traditionally been critical in the region as the resource for export, especially to the region's neighbours – such as Japan, the Republic of Korea (hereafter Korea), Taiwan, China, and India – and now as the driver to fuel the region's rapid economic growth. The region has some of the biggest LNG exporters in the world and now some of the emerging LNG importers. In this regard, in addition to external LNG exports, intraregional LNG trade, as some economies in the ASEAN region have started, will import LNG, including Thailand, Singapore, Malaysia, Indonesia, Myanmar, and now the Philippines and Viet Nam.

Globally, LNG liquefaction plants with significant capacity have started operation in recent years, and the world is expected to see further significant expansion of LNG production in the next decade. Those new projects will compete for LNG customers, and existing LNG production projects will vie for contract renewals.

In other words, this creates additional opportunities for LNG players to make the LNG market more flexible and LNG contract prices more attractive. In the past, LNG used to be marketed and sold to traditional utility markets. The value chain was constructed in a vertically integrated manner. Those with LNG volumes may use their expertise to develop emerging LNG markets and optimise LNG volumes between different international LNG markets.

This study firstly aims to identify how LNG and natural gas can best fit into the energy and transition agenda, especially in the ASEAN region. The study will look at recent and expected developments of price formation in the LNG markets and explore what can be done to promote more healthy development of the market balancing the needs of different stakeholders in the market.

This study also aims to pursue a resilient strategy to address the methane emissions issue across the natural gas value chain in the ASEAN region—a region of significant importance in the global natural gas industry. Whilst methane emissions issues have gained considerable attention in Western Europe and North America, the ASEAN region has been slower to recognise the importance of these issues, with regional governments lagging in policy and regulatory development.

In recent years, international initiatives such as the Global Methane Pledge, the International Methane Emissions Observatory, the Oil and Gas Methane Partnership 2.0, the Coalition for LNG Emission Abatement toward Net-zero, and the ASEAN Energy Sector Methane Leadership Program have highlighted the growing attention to methane emissions management. Within this context, the natural gas value chain is increasingly seen as a 'low-hanging fruit' for emissions reductions across the

spectrum of methane emissions sources. The global gas crisis in 2022 again underscored the importance of sustainability in natural gas supply, alongside supply security.

One key reason for this attention is the suspected higher global warming potential (GWP) of methane over shorter time scales. Whilst methane is estimated to have a GWP of 29.8 over 100 years, its 20-year GWP is significantly higher at 82.5 (US EPA, 2022). Because of methane's shorter atmospheric lifespan compared with CO_2, the 20-year GWP has been increasingly cited in recent discussions.

The momentum behind methane emissions management gained speed in mid-2023, with the issue being addressed at the annual LNG Producer–Consumer Conference in Tokyo and the Energy Asia event in Kuala Lumpur. Several international initiatives are also underway to develop standards for methane (greenhouse gas emissions measurement, reporting, verification, leak detection and repair, and abatement measures.

Ultimately, enhanced efforts to reduce and manage methane emissions should enable natural gas and LNG to play a pivotal role in the energy transition whilst improving energy security and resilience in the ASEAN region and Northeast Asia, which is expected to continue relying on ASEAN LNG supply, albeit to a lesser extent.

The ASEAN region has also seen notable developments in raising awareness of methane emissions, led by the industry itself. Since 2021, the ASEAN Methane Roundtable series (PETRONAS, 2021a), led by Malaysia's PETRONAS, Thailand's PTT, and Indonesia's PERTAMINA, has made significant strides. PETRONAS joined the Oil and Gas Methane Partnership 2.0 (OGMP 2.0) in November 2022 (PETRONAS, 2022). The Japan Organization for Metals and Energy Security and JGC Holdings of Japan have also expressed willingness to cooperate in the region, including site-level emissions measurement programmes.

During this study, two online workshops were held to enhance global and regional understanding of the issue. The study team remains committed to understanding the efforts and initiatives undertaken by companies, industry associations, and government authorities in the region to help develop effective strategy for tackling the issues.

Executive Summary and Key Findings

This report begins by examining recent developments in increasingly volatile global liquefied natural gas (LNG) markets, with a focus on major regions and the underlying drivers of price fluctuations. The analysis highlights that LNG prices have become more volatile in both speed and magnitude than in previous years, reflecting rapidly shifting market balances. Price movements now occur more abruptly and over wider ranges: during periods of tight supply, prices spike to exceptionally high levels, while in periods of oversupply, prices can fall sharply and, in some cases, even enter negative territory, where sellers effectively pay offtakers to lift cargoes.

The report then analyses natural gas supply and demand trends in Southeast Asian economies, taking into account economic growth trajectories and the impacts of the recent global energy crisis. Particular attention is paid to both traditional gas-producing and LNG-exporting countries, as well as emerging LNG-importing markets. In mid-2023, the Philippines and Viet Nam began importing LNG, marking a significant shift in regional gas market dynamics. The future growth of these nascent LNG markets will be closely linked to developments in the global LNG market, particularly in terms of price stability and supply availability.

Next, the report examines the key factors contributing to amplified LNG price volatility. These include the European Union's substantial shift towards increased LNG imports, which is expected to persist at least in the medium term and potentially over the longer term. China's rapid expansion of natural gas demand has also played a central role in global LNG market growth, contributing to seasonal supply tightness during winter months, while fluctuations in China's demand have had significant spillover effects on global markets. Developments in India and neighbouring South Asian countries are also analysed, providing a comparative perspective relative to Southeast Asia and China. In addition, the report reviews the evolution of wholesale gas pricing mechanisms across regions and over time, highlighting structural differences that influence market behaviour.

LNG supply from the United States – widely expected to underpin future growth in global LNG consumption – is examined in detail. Particular attention is given to policy developments under the new United States administration and their potential implications for global LNG markets, including Asia. This analysis is especially relevant for Asian consumers seeking long-term assurance of affordable and reliable LNG supplies to support economic growth. While US LNG supply presents certain challenges, its scale, flexibility in destination, and pricing structures remain highly attractive to emerging LNG-importing countries in the region.

The report also synthesises key findings from four discussion events held in Hiroshima (October 2024), Washington, DC (January 2025), Houston (March 2025), and Tokyo (June 2025). While detailed summaries of each event are presented in Chapter 4, several common themes emerged across all discussions:

- For LNG to play a meaningful role as a transition energy source – particularly in Asia – affordability is essential, requiring stable, sufficient, and cost-effective supply.
- Significant uncertainties remain on both the supply and demand sides of the LNG market. In addition, complex issues such as the allocation of costs associated with greenhouse gas (GHG) emissions reduction for the sustainable use of LNG underscore the importance of regular and structured dialogue amongst LNG sellers and buyers, as well as between governments and industry stakeholders.

Based on these findings, the report proposes the following policy recommendations:

- Clearly define and articulate the role of LNG and natural gas in ensuring energy security and supporting the energy transition.
- Secure sufficient long-term LNG supply sources for ASEAN.
- Enhance ASEAN's LNG purchasing power by aggregating regional demand and co-operating with other Asian countries, including Japan, to optimise cargo procurement.
- Ensure adherence to fundamental methane emissions management practices across the LNG value chain.
- Play a proactive role in global methane emissions management while safeguarding regional energy security.
- Promote the standardisation and harmonisation of methane emissions measurement and reporting guidelines.
- Leverage the expertise of Japanese companies to accelerate methane emissions management efforts.
- Signal a clear preference for lower-emissions gas in procurement and contracting decisions.

The authors hope that these recommendations will serve as a foundation for continued dialogue and concrete initiatives to support the stable development of the LNG industry, particularly in the ASEAN region, during the energy transition.

Chapter 1

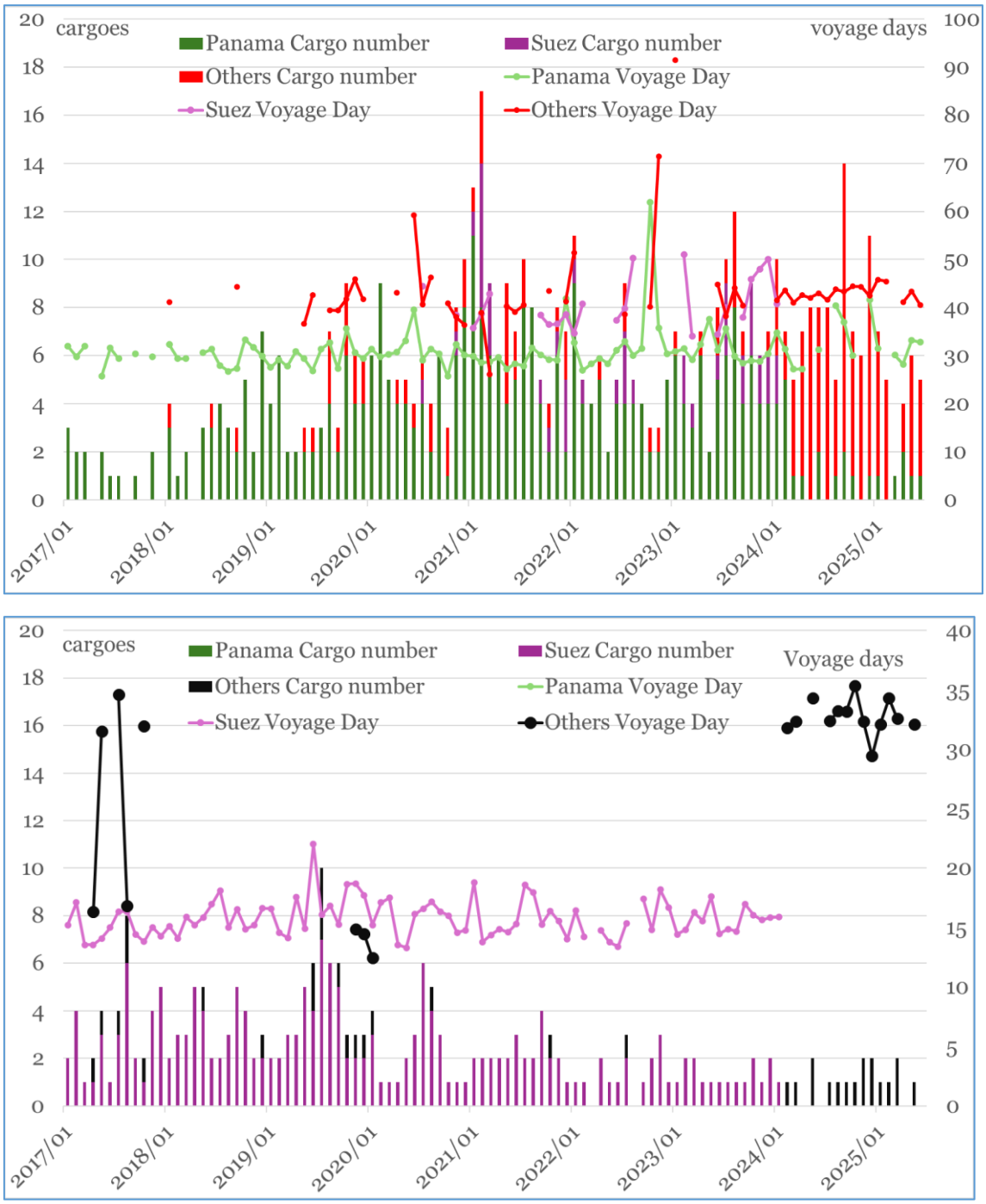
Relatively Calm Period of LNG Prices with Signs of Destabilisation

1.1 Outline of Price Fluctuations

Compared to the previous volatile period in 2022 after the Russian invasion of Ukraine, the global liquefied natural gas (LNG) and natural gas industry has seen relative stability from 2023 to 2025 due to mild weather conditions and improving supply fundamentals, especially in Europe. However, until 2026 when further LNG capacity is expected to be added in the United States and Qatar, global LNG demand and supply are expected to remain tight. Therefore, if unexpected events occur in certain supply areas, the global LNG situation could easily change. Especially during the winter in the northern hemisphere, when global gas demand peaks, LNG prices could instantly surge. In addition, the unforeseen situation in Ukraine continues to provide uncertainty towards the gas supply outlook as well.

Recently, choke point risks have also increased uncertainty for global LNG supply. The number of LNG cargo shipments crossing the Panama Canal and the Suez Canal has decreased due to lower water levels and political tensions, respectively. Consequently, more LNG cargoes are detouring via the Cape of Good Hope, highlighting concerns about the Panama and Suez Canals. The International Energy Agency points out in its Gas Market Report (Q3 2025) that shipping constraints due to these choke point risks could lead to higher LNG supply costs.

Figure 0.1 LNG Cargo Shipments from the United States to Japan, and Qatar to Italy (January 2017–June 2025)



Source: Compiled by the authors based on data from ICIS LNG Forecast (access date: 22 December 2025).

The relative stability of the global LNG market since 2023 has increased the affordability of LNG in the ASEAN region as well, but this stability remains fragile. Viet Nam and the Philippines have started and have been increasing imports of LNG. However, the factors mentioned above, including the uncertainty of supply sources and choke points, could easily diminish the affordability of LNG in the ASEAN region, which could bring about serious effects on economic development and steps towards decarbonisation. In order to stimulate and maintain LNG demand in the ASEAN region, a more stable supply at affordable price levels is required, since LNG receiving infrastructure needs a certain amount of investment in advance.

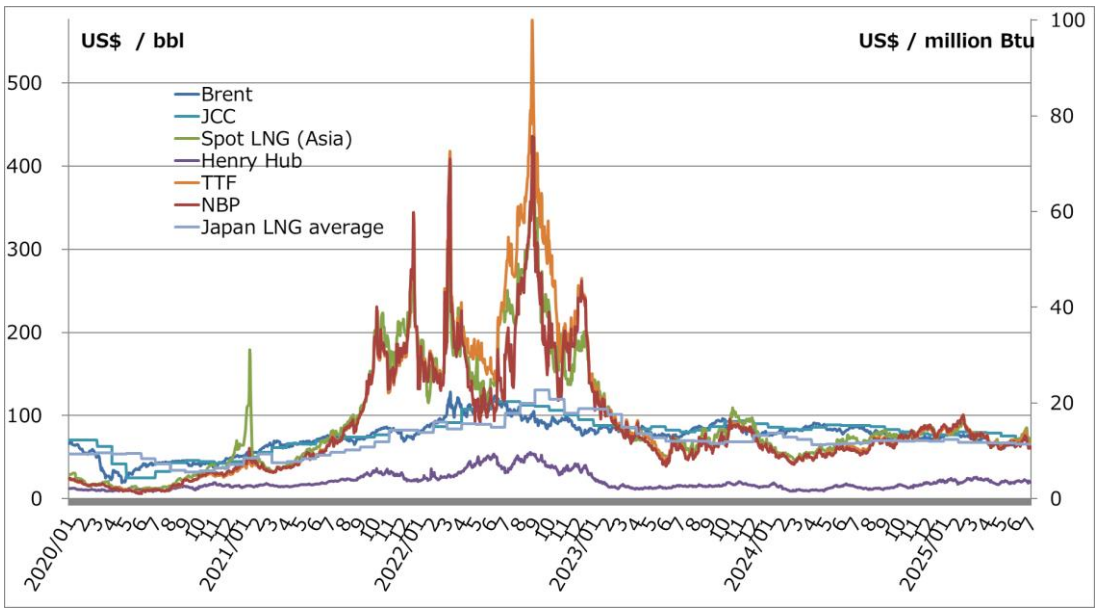
1.2 Global LNG and Gas Prices Move Faster and Wider

In the second half of 2022, after the beginning of the war in Ukraine in the first half of the year, the Title Transfer Facility (TTF) in the Netherlands, the representative index in continental Europe) prices (front-month futures prices) were exceptionally higher than other regional gas prices and more expensive than periods in the past. Assessed Asian spot LNG prices tended to follow higher TTF prices during the period.

From August 2021 until April 2023, spot LNG and gas prices were more expensive than crude oil, although the ordinary pricing range of LNG imported into Asian countries under long-term contracts was linked to some extent to the percentage of oil prices. This demonstrated how extraordinarily high the spot prices were during the period.

Since the second quarter of 2023, spot prices have declined to the rate seen before the turbulent period. However, they are still fluctuating and higher than those of the pre-Ukraine war level, which have made it difficult for sound development of LNG markets and economic development in Southeast Asian countries (Figure 1.2).

Figure 0.2 Spot LNG Prices (January 2021–July 2025)



bbl = barrel, Btu = British thermal unit, JCC = Japan Crude Cocktail, LNG = liquefied natural gas, TTF = Title Transfer Facility, NBP = National Balancing Point.
Source: Analysis by Institute of Energy Economics, Japan.

There were some major spikes in assessed Asian spot LNG prices between 2021 and 2022, but the prices have declined rapidly since the beginning of 2023 (Table 1.1).

From October 2021 until the end of 2022, assessed Asian spot LNG prices were strongly influenced by European spot gas prices, which were heavily affected by several factors, including a relatively cold winter and supply shortage concerns following the outbreak of the war in Ukraine.

Immediately after 24 February 2022, when Russia invaded Ukraine, the TTF rose to record-high levels, driving up assessed Asian spot LNG prices as well.

On 7 March 2022, the TTF (the settlement price of the front-month futures) hit US$72 per 1 million British thermal units (MBtu) (€227.201 per megawatts per hour [MWh]) on fears of Russian pipeline gas supply disruptions, accompanied by assessed Asian spot LNG prices, which temporarily soared to US$85 per MBtu.

As the 2022 summer season began, the TTF rose due to Nord Stream's throughput reduction, marking US$99 per MBtu (€339.196/MWh) on 26 August.

However, after that, European underground gas inventories piled up steadily amidst the record-high temperatures in the 2022–2023 winter season. Assessed Asian spot LNG prices also fell to the mid-US$10s per MBtu range by the middle of July 2023 and have remained around that level since then. This stability is also due to relatively moderate LNG demand of Japan and China.

Table 0.1 Major Spikes in Spot Prices since 2021

	Assessed Asian Spot LNG Prices Price at the Peak and Circumstances in the Asian Market	TTF Price at the Peak and Circumstances in the European Market
October 2021	**US$56/MBtu**	**US$54/MBtu**
	Rise of European spot prices Severe winter	Severe winter expectation Power supply shortages Low inventory in gas storage Supply shortages (concerns) - Pipeline gas supply from Russia Price hike of European Union Emissions Trading System
December 2021	**US$44/MBtu**	**US$60/MBtu**
	Rise of European spot prices Severe winter Supply shortages (concerns) - LNG supply outages - Diversion of LNG to Europe	Severe winter Power supply shortages Low inventory in gas storage Supply shortages (concerns) - Pipeline gas supply from Russia
February 2022	Russian Invasion of Ukraine	
March 2022	**US$84.8/MBtu**	**US$72/MBtu**
	Rise of European spot prices Supply shortages (concerns) - LNG supply outage concerns - Diversion of LNG to Europe	Supply shortages (concerns) - Pipeline gas supply from Russia
August 2022	**US$71/MBtu**	**US$94.2/MBtu**
	Rise of European spot prices	Supply shortages (concerns) - Maintenance of Nord Stream 2 - Maintenance of gas fields in Norway
December 2022	**US$40/MBtu**	**US$46.1/MBtu**
	Severe winter End of zero-COVID-19 policy in China	Decreasing pipeline gas supply from Russia Concerns over power shortages Nuclear outages in some countries
2023–	Both prices have been declining and relatively stable level (around US$11–US$13/MBtu)	

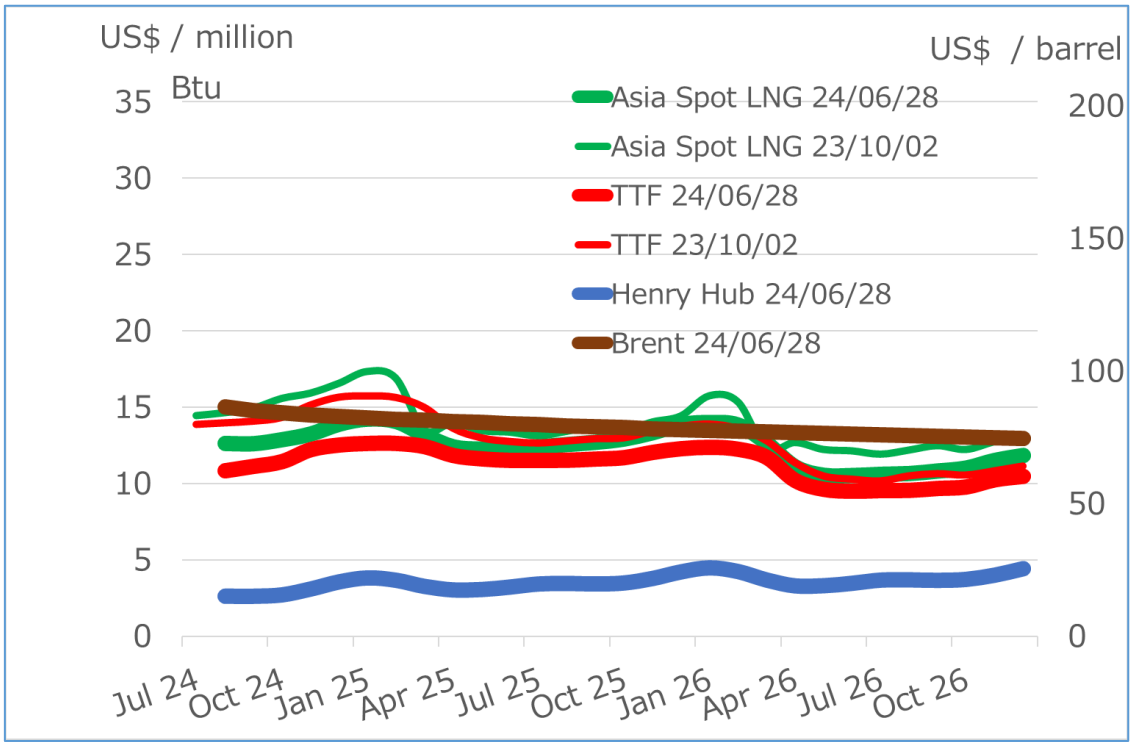
MBtu = million British thermal unit, LNG = liquefied natural gas, TTF = Title Transfer Facility.
Source: Analysis by Institute of Energy Economics, Japan.

1.3. Market Sentiments Can Shift Quickly

Reflecting the relatively stable recent LNG prices mentioned in the previous section, spot price expectations for Asian Spot LNG, Title Transfer Facility, and Henry Hub futures are also stable (Figure 1.3). This forecast is also due to expectations that new LNG projects are also expected to start production and shipment towards 2026.

However, market sentiments can shift very quickly at any time. The fluctuation can be tremendous, especially if multiple factors affecting LNG supply coincide.

Figure 0.3 Changes in Asia Spot LNG, TTF, Henry Hub Forward Curves



Million Btu = million British thermal unit, TTF = Title Transfer Facility.
Source: Based on Data of Chicago Mercantile Exchange.

Chapter 2
Supply–Demand Situation in Southeast Asian Countries

2.1 Outline of Gas Demand in ASEAN

The Association of Southeast Asian Nations (ASEAN) used to be a major liquefied natural gas (LNG) exporting region. However, due to increasing domestic energy demand and relatively slow progress in gas production development in the region, Thailand, Indonesia, Malaysia, Singapore, the Philippines, and Viet Nam have started importing LNG, whilst Myanmar only imported LNG in 2020 and 2021. Whilst it is forecast that ASEAN as a region will continue to be a net natural gas exporter until 2030, the region's LNG imports are expected to grow.

The primary LNG demand sectors in ASEAN are the power and industry sectors. Natural gas is already a major fuel for power generation in many ASEAN countries. Because of sustained demand growth of electricity, the public preference for a cleaner fuel, and depleting domestic production, natural gas will remain as one of preferred choices for new power generation requirements.

2.1.1 Economy and Energy Demand Outlook

Amongst emerging and developing economies, ASEAN has recently achieved remarkable economic development. Its population increased by 10%, whilst its real gross domestic product (GDP) increased by 50% from 2011 to 2021. In accordance with this growth, its primary energy consumption increased by 30% in the same period. Therefore, a stable supply of energy at low cost is key to ASEAN's economic development. Meanwhile, as actions for climate change grows its importance globally, ASEAN is also facing the challenge of curbing greenhouse gas (GHG) emissions whilst increasing its energy supply.

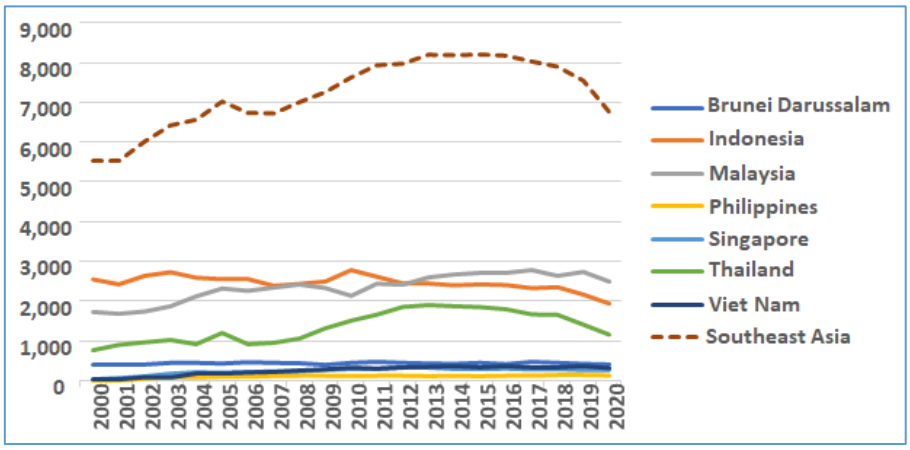
Even in the ASEAN region, where energy consumption continues to increase, more and more countries have been setting carbon neutrality goals since the United Nations Climate Change Conference (COP26) in the United Kingdom in 2021. So far, eight of the 10 ASEAN Member States – Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Singapore, Thailand, and Viet Nam – have already declared net-zero emissions goals.

To reconcile their increasing energy demands whilst pursuing carbon neutrality goals, natural gas, a lower-emissions fossil fuel, is expected to play an important role, especially during the energy transition. In fact, there has been strong gas demand growth in the ASEAN region for more than 20 years, driven by significant

economic and population growth. Gas demand doubled, especially in the power sector, between 2000 and 2020 (Figures 2.1 and 2.2).

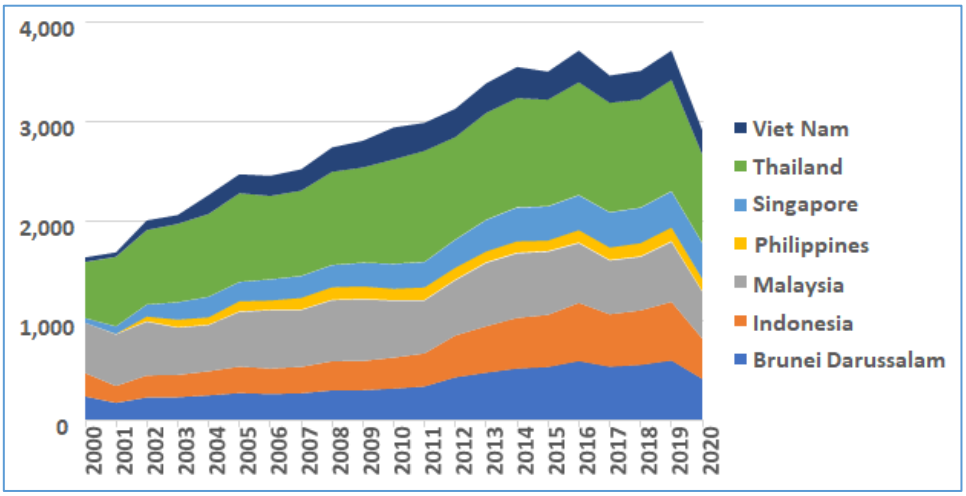
As of 2022, natural gas accounted 19% of primary energy supply in ASEAN. Going forwards, it will be consumed mainly to meet the high-temperature heat demand of industrial furnaces, which are extremely difficult to electrify in the industry sector, and as feedstock for petrochemicals. According to the *IEEJ Outlook 2025*, either in the Reference Case and Advanced Technologies Case, the portion of natural gas will increase (Figure 2.3).

Figure 0.1 Total Gas Supply by Economy in Southeast Asia (PJ)



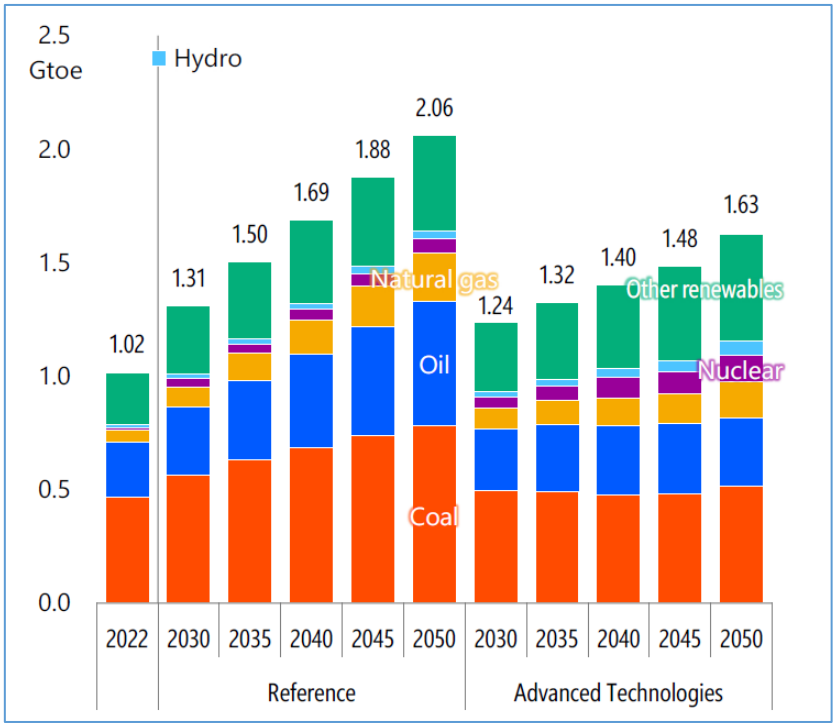
PJ = petajoule.
Source: Based on data from the Asia Pacific Energy Resource Centre.

Figure 0.2 Gas Consumption for Electricity Generation (PJ)



PJ = petajoule.
Source: Based on data from the APEC Energy Working Group Expert Group on Energy Data and Analysis.

Figure 0.3 Final Energy Consumption in ASEAN

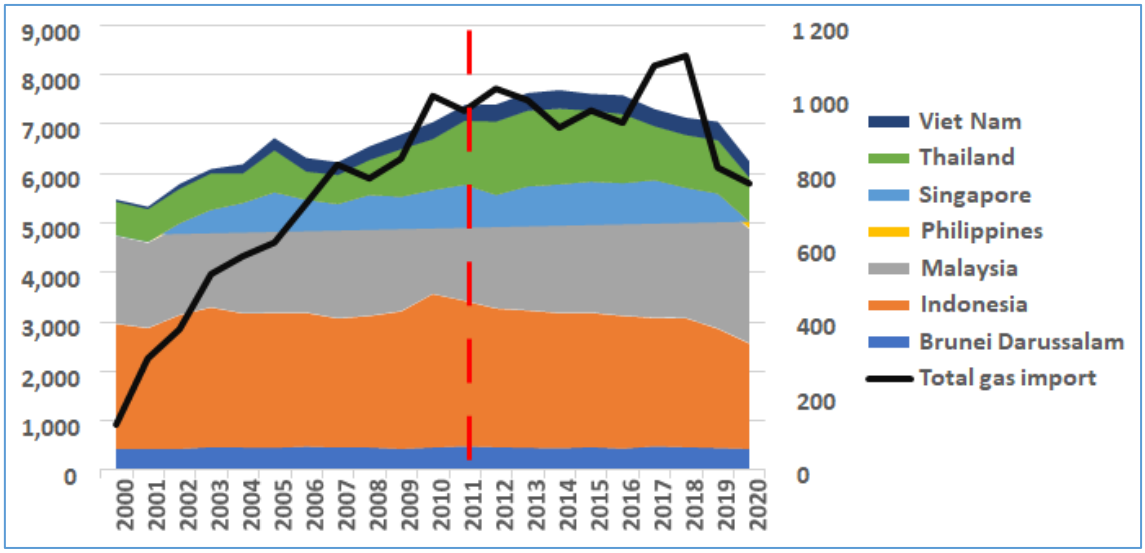


Gtoe = gigatonnes of oil equivalent.
Note: Reference is the base case in the IEEJ Outlook.
Source: IEEJ (2024).

2.1.2 Production and Imports of Natural Gas

Indonesia, Malaysia, and Thailand consume more than 80% of the total demand for natural gas of Southeast Asian countries. The region has been an LNG importer since 2011, when Thailand first imported LNG. Before 2011, Malaysia, Singapore, and Thailand had imported gas from Indonesia, Myanmar, and joint development areas with neighbouring countries. Within the region, some countries import LNG; others export it. Each economy wants to diversify its gas sources based on its specific circumstances.

Figure 0.4 Gas Production and Imports (PJ)



PJ = petajoule.
Note: Left axis shows gas production and right axis shows gas imports.
Source: Based on data from the APEC Energy Working Group Expert Group on Energy Data and Analysis.

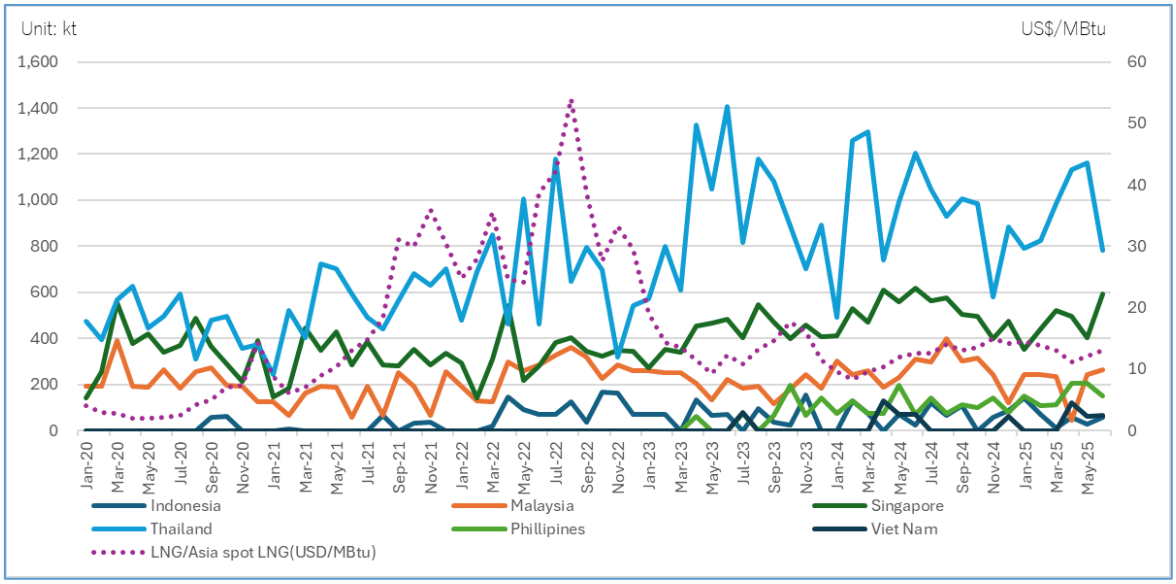
2.1.3 LNG Spot Prices and Imports

From the second half of 2021 to 2022, limited LNG supplies and the war in Ukraine caused assessed spot LNG prices in Asia to rise to unprecedented levels. Despite those high LNG prices, the Southeast Asian LNG importing countries did not reduce their LNG imports. Furthermore, Indonesia, Malaysia, and Thailand increased LNG imports in 2022, although the growth rates may have been lower than anticipated. In 2023, Thailand and Singapore significantly increased LNG imports.

As Figure 2.4 shows, since 2023, taking advantage of the lower assessed spot prices, Thailand increased its imports due to a decline in domestic natural gas production. In May 2023, the Philippines imported its first LNG from the United Arab Emirates. Viet Nam also started importing LNG in July 2023.

By May 2023, assessed Asian LNG spot prices had declined significantly to the level seen in the first half of 2021 and have remained stable since. This price decline has incentivised several LNG importers, particularly Thailand, to accelerate LNG imports to sustain their energy security. Concurrently, Thailand also has increased its hydropower imports from the Lao PDR. Malaysia has increased domestic gas production to meet its power generation and industrial demands. The Philippines has increased its coal imports to sustain its power generation due to the decline of gas production at the Malampaya gas field. Viet Nam has benefited from increased power generation from renewable energy sources, particularly hydropower. Viet Nam's domestic oil and gas output declined significantly during the same period.

Figure 0.5 LNG Spot Prices and Imports by Country



kt = kilotonne, LNG = liquefied natural gas, MBtu = metric million British thermal unit.
Source: Based on data from Cedigaz and Investing.com.
https://jp.investing.com/commodities/lng-japan-korea-marker-platts-futures-historical-data (accessed 25 July 2025).

2.1.4 LNG-receiving Terminals in Southeast Asia

Several countries in the region have decided to build LNG-receiving terminals due to factors, including:

- Increasing gas demand
- Declining domestic gas production due to matured oil and gas fields
- Diversification of gas supply
- Geographic separation of gas supply and demand centres

Although Southeast Asia's LNG purchases are far behind the world's major importing countries in Northeast Asia, given its geographical proximity to those nations and their import cargo routes, ASEAN nations could make effective use of these LNG terminals.

2.2 Thailand

2.2.1 Economy and Energy Demand Outlook

According to the *IEEJ Outlook 2025*, Thailand's primary energy consumption is forecast to increase by an average of 1.0% per year The forecast is based on an assumed economic growth rate (2015 prices) of 3.1% annually from 2022 to 2050. The energy mix in 2050 will comprise 9% coal, 36% oil, 24% natural gas, 3.5% nuclear, 0.9% hydro, 20% biomass and waste, 2.9% solar, wind, etc. (Table 2.1).

2.2.2 Natural Gas Industry

PTT, a state-owned enterprise under the Ministry of Energy, controls the gas business in Thailand. Natural gas resources in Thailand are expected to decline as domestic reserves reach a plateau. Since natural gas will continue to be consumed mainly for power generation, the government is working to expand domestic production, diversify import sources, and improve gas infrastructure.

To address the gas demand, the government is working to secure supplies both domestically and internationally. Thailand started gas imports from Myanmar through pipelines in 1998 and started importing LNG in 2011, with ongoing expansion of receiving terminals. Concerning LNG, Thailand has decided to participate in an offshore gas field and LNG project with significant potential in Mozambique and is taking measures to meet future demand growth.

Thailand's energy policy sets out several measures to maintain the longevity of domestic gas fields for 30 years or more based on 'proven and probable' reserves. The policy also seeks to manage natural gas procurement in line with domestic needs, monitor the development of current gas fields, and reduce the share of gas-fired power generation to below 70%. Additionally, the policy also includes strengthening relations with gas-producing countries and promoting the introduction of natural gas in the transport and other private sectors.

Foreign investment in Thailand is permitted in upstream gas development. As for existing gas fields, most production comes from offshore gas fields in the Gulf of Thailand. However, some onshore gas fields with relatively high production volumes, such as Phu Horm, started production in 2006. In addition to PTTEP (exploration and production unit of PTT) as the main operator, foreign companies such as Chevron, ExxonMobil, and Mitsui Oil Exploration Company are the project stakeholders.

Table 0.1 Primary Energy Consumption in Thailand

	(Mtoe)							Shares (%)		
	1990	2000	2010	2022	2030	2040	2050	1990	2022	2050
Total*	42	73	118	133	142	160	175	100	100	100
Coal	3.8	7.7	16	18	17	17	16	9	13	9
Oil	18	32	45	55	55	60	63	43	41	36
Natural gas	5	17	33	33	40	43	42	12	25	24
Nuclear	-	-	-	-	-	1.8	6.2	-	-	3.5
Hydro	0.4	0.5	0.5	0.6	1.3	1.5	1.7	1	0.4	0.9
Geothermal	0	0	0	0	0	0	0	0	0	0
Solar, wind, etc.	-	-	0	0.7	1.8	3.5	5.2	-	0.5	2.9
Biomass and waste	15	15	23	23	24	30	36	35	17	20
Hydrogen	-	-	-	-	0	0	0	-	-	0

Mtoe = million tonnes of oil equivalent.

Note: *Trade of electricity and heat not shown.

Source: IEEJ (2024).

In the domestic gas business sector, PTT is responsible for almost all gas transmission and distribution sections, with the total length of pipelines in the country reaching 4,000 kilometres. The PTT group has played a dominant role in the construction, ownership, and operation of gas transportation and LNG terminals and is involved in development of some gas fields.

However, given the limitations on domestic gas resources, the Ministry of Energy, has been progressively developing rules for third-party use of onshore gas pipelines and LNG terminals. Besides, PTT was an early player in natural gas development in neighbouring Myanmar, acquiring partial interests in the Yadana and Yetagun gas fields, and has been importing gas through pipelines since 1998. PTT also started importing gas from the Zawtika gas field in August 2014. PTT maintains the equity interest in the Myanmar gas fields and gas imports from them, after other foreign partners exited the country in 2023 and 2024.

In December 2021, PTT announced a 5-year investment plan for 2022–2026, with a total investment of B102,165 million. By business segment, the largest investment (45%) will be in the gas business, including gas pipelines connecting power plants and developing the second LNG-receiving terminal at Nong Fab in the eastern province of Rayong.

2.2.3 LNG Business

In 2011, PTT completed construction of an LNG-receiving terminal with a capacity of 5 million tonnes per annum (Mtpa) and started operation at Map Ta Phut, Rayong Province. The rapid increase in LNG imports has led to construction of more LNG terminal capacity. PTT previously monopolised LNG imports but has been opened up for third parties.

In January 2020, the Ministry of Energy instructed PTT to consider procuring LNG on the spot market. The ministry indicated that if PTT imported LNG at a lower price, it would temporarily reduce offshore production and extend the longevity of gas fields in the Gulf of Thailand.

In April 2021, the Electricity Generating Authority of Thailand (EGAT), a state-owned enterprise, and PTT announced that they would jointly conduct a feasibility study to develop a floating storage and regasification unit (FSRU) (Praiwan, 2021a). The FSRU would be located offshore in the Gulf of Thailand and supply LNG to a power plant in Phunphin District, Surat Thani Province, southern Thailand. In July 2021, EGAT announced it would take a stake in the second LNG terminal project under construction by PTT in the Nong Fab area of the eastern province of Rayong (Praiwan, 2021b).

In August 2021, the National Energy Policy Committee of Thailand approved the import of LNG by seven state-owned and private companies to make the LNG market more competitive (Praiwan, 2021c). The seven companies are PTT, EGAT, B.Grimm Power, Gulf Energy Development, Hinkong Power, EGCO, and Siam Cement.

In July 2022, Thailand's National Energy Policy Committee approved a plan for PTT to import an additional 1 million tonnes (Mt) of LNG under a long-term contract. Earlier, 5.2 Mt of LNG imports had been authorised for PTT. The purpose of the plan was to stabilise the rising prices of LNG.

In September 2024, PTT concluded term LNG purchase contracts with Oman LNG and Brunei LNG, respectively, covering a period between 2025 and 2029.

A joint venture between Gulf Energy and PTT, Gulf MTP LNG Terminal Company, plans to start construction of the country's third LNG receiving terminal in 2025, targeting operation start in 2029.

2.3 Malaysia

2.3.1 Economy and Energy Demand Outlook

The *IEEJ Outlook 2025* forecasts Malaysia's primary energy consumption to increase by an average of 1.6% per year, based on an assumed economic growth rate (2015 prices) of 3.5% annually from 2022 to 2050. The energy mix in 2050 will comprise 9.6% coal, 20% oil, 64% natural gas, 2.3% nuclear, 2.3% hydro, 1.8% biomass and waste, and 0.9% solar, wind, etc. (Table 2.2).

Table 0.2 Primary Energy Consumption in Malaysia

	(Mtoe)							Shares (%)			
	1990	2000	2010	2022	2030	2040	2050	1990	2000	2022	2050
Total*	21	48	72	99	120	140	156	100	100	100	100
Coal	1.4	2.3	15	24	24	21	15	6.4	4.8	24	9.6
Oil	11	19	25	25	30	31	31	54	40	25	20
Natural gas	6.8	25	31	47	60	77	100	32	51	47	64
Nuclear	-	-	-	-	-	3.7	3.7	-	-	-	2.3
Hydro	0.3	0.6	0.6	2.7	2.9	3.4	3.6	1.6	1.2	2.7	2.3
Geothermal	-	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	-	0.2	0.4	0.9	1.4	-	-	0.2	0.9
Biomass and waste	1.2	1.3	0.8	1.2	2.5	2.6	2.7	5.8	2.6	1.2	1.8
Hydrogen	-	-	-	-	-0.0	-0.0	-0.0	-	-	-	-0.0

	(Mtoe)							Shares (%)			
	1990	2000	2010	2022	2030	2040	2050	1990	2000	2022	2050
Total*	21	48	72	99	120	140	156	100	100	100	100
Coal	1.4	2.3	15	24	24	21	15	6.4	4.8	24	9.6
Oil	11	19	25	25	30	31	31	54	40	25	20
Natural gas	6.8	25	31	47	60	77	100	32	51	47	64
Nuclear	-	-	-	-	-	3.7	3.7	-	-	-	2.3
Hydro	0.3	0.6	0.6	2.7	2.9	3.4	3.6	1.6	1.2	2.7	2.3

Geothermal	-	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	-	0.2	0.4	0.9	1.4	-	-	0.2	0.9
Biomass and waste	1.2	1.3	0.8	1.2	2.5	2.6	2.7	5.8	2.6	1.2	1.8
Hydrogen	-	-	-	-	0	0	0	-	-	-	0

Mtoe = million tonnes of oil equivalent.
Note: * Trade of electricity and heat not shown.
Source: IEEJ (2024).

2.3.2 Natural Gas Industry

As the decline in production from mature oil and gas fields poses a major challenge, the government has introduced measures to promote upstream investment and tax incentives. PETRONAS Carigali (the national energy company's unit) runs the upstream sector. Malaysia is Southeast Asia's largest natural gas producer, with production reaching 81.1 billion cubic metres (Bcm) in 2023 (Energy Institute, 2023).

In August 2017, Sarawak state announced the establishment of Petros, an oil and gas company wholly owned by the state (Sarawak Government, 2017). The state, which had only participated in some downstream projects until then, started full participation in exploration and development projects of oil and gas.

In March 2021, PETRONAS and China National Offshore Oil Corporation signed a memorandum of understanding (MOU) for partnership in energy security, mainly in LNG and upstream sectors, and in developing environment-friendly energy (CNOOC, 2021). The companies cooperate in key strategic areas such as LNG projects, oil and gas exploration, production, refining, engineering services, specialty chemicals, and lubricants.

In April 2022, Petronas announced its withdrawal from the Yetagun gas field operations off the southern coast of Myanmar, where the company held a 40.9% interest as the main operator of the project (PETRONAS, 2022a). PETRONAS shares the gas field with Myanmar Oil and Gas Enterprise and Japanese and Thai companies. However, international criticism was mounting that the revenues were funding the military regime in Myanmar.

In September 2022, Sarawak Shell, a subsidiary of Shell plc and together with PETRONAS, made the final investment decision (FID) to develop the Rosmari-Marjoram gas project, located in Malaysia, 220 kilometres from the coast at Bintulu (Shell, 2022). This project, powered by renewable energy, is expected to produce 800 million standard cubic feet per day (Mscf/d) of gas starting in 2026.

In September 2022, Mubadala Energy announced that it had discovered a gas reservoir offshore Malaysia, in Block SK320, offshore Sarawak (Mubadala Energy, 2022). The Cengkih-1 exploration well, where the gas was discovered, is one of the fields in the SK320 block. It is located near the Pegaga field, which recently confirmed initial reserves of an additional 1 trillion cubic feet (Tcf). Mubadala Energy operates the SK320 concession, holding a 55% interest. PETRONAS and a Shell subsidiary hold the remainder.

2.3.3 LNG Business: Exports

Table 2.3 shows LNG liquefaction projects in Malaysia. PETRONAS FLNG 1 was the world's first floating production facility, raising hopes for the country's commercialisation of stranded gas fields. In March 2021, PFLNG2, PETRONAS' second floating LNG production and storage unit, became operational, and the first cargo was shipped to Thailand.

Table 0.3 LNG Projects in Malaysia

Liquefaction Terminals	Capacity (Mtpa)	Operation Start	Stakeholders
MLNG I (Satu) (Trains 1-3)	8.4	1983	MLNG (PETRONAS 90%, Sarawak state government 5%, Mitsubishi 5%)
MLNG II (Dua) (Trains 4-6)	9.6	1995	MLNG Dua (PETRONAS 80%, Mitsubishi 10%, Sarawak state government 10%)
MLNG III (Tiga) (Trains 7, 8)	7.6	2003	MLNG Tiga (PETRONAS 60%, Sarawak state government 25%, ENEOS 10%, DGN 5% (Mitsubishi: JAPEX = 4: 1))
PETRONAS LNG 9 (Train 9)	3.6	2017	PETRONAS 65%, ENEOS 10%, PTTGL 10%, Sarawak state govt. 10%, Sabah state government 5%
PETRONAS FLNG 1 (PFLNG SATU) (FLNG)	1.2	2017	PETRONAS
PETRONAS FLNG 2 (PFLNG DUA) (FLNG)	1.5	2021	PETRONAS
PETRONAS FLNG 3 (PFLNG Tiga) (FLNG) (Unnamed yet)	2.0	2026 (Under Planning)	PETRONAS
ZFLNG (Unnamed yet)	2.0	NA	PETRONAS, Sabah state government

FLNG = floating natural gas, LNG = liquefied natural gas, Mtpa = million tonnes per annum, NA = not available.
Source Analysis by Institute of Energy Economics, Japan.

In April 2022, PETRONAS and Sabah Oil & Gas Development Corp, owned by the Sabah state government, signed an MOU for a near-shore floating LNG (FLNG) facility in Sabah. The facility will have an LNG production capacity of 2 Mtpa, with an FID revealed in early January 2023 (JGC Holdings Corporation, 2023b). The FLNG facility is under construction at the Samsung Heavy Industries shipyard in Geoje Island, Korea. The third FLNG facility by PETRONAS is targeted to commence commercial

operations by the second half of 2027. The FLNG facility will be moored at the Sipitang Oil and Gas Industrial Park in Sabah.

In September 2022, YPF, Argentina's state-owned oil company, signed a joint study and development agreement with PETRONAS for LNG-related projects in Argentina (PETRONAS, 2022b). The agreement covers unconventional gas production, pipeline and infrastructure development, LNG production, marketing, and logistics. Argentina has the world's second-largest reserve of unconventional gas.

In October 2022, PETRONAS declared a force majeure for gas supply to MLNG Dua (PETRONAS, 2022c) due to a pipeline leak on 21 September 2022 caused by soil movement near the Sabah–Sarawak gas pipeline KP201. This incident affected the gas supply to MLNG Dua's production facilities at the PETRONAS LNG complex in Bintulu, Sarawak. However, the force majeure only affected gas supplies to MLNG Dua, whilst other LNG production facilities in the PETRONAS LNG complex are operating as planned. The incident affected supplies to LNG buyers under contract.

2.3.4 LNG Business: Imports

LNG imports by PETRONAS began in 2013 to help alleviate gas shortages on the Malay Peninsula, whilst Malaysia is the world's fifth largest LNG producer in 2023. The LNG-receiving terminals are the Melaka terminal (operational in 2013, 3.8 Mtpa) and the Pengerang terminal (operational in 2017, 3.5 Mtpa), both owned by PETRONAS.

The country's major demand centres, such as Kuala Lumpur, are located on the Malay Peninsula (west side of the country), whilst its major natural gas resources exist in Sarawak (east side of the country). Initially, the demand on the Malay Peninsula used to be supplied from the production in basins offshore from the peninsula. However, as the production started declining whilst the demand gas demand increased, Malaysia needed to find another supply source to meet the demand on the peninsula. Pipeline connection from Sarawak to the Malay Peninsula was difficult because of the distance (over 1,000 kilometres).

In October 2020, Petrolife Aero Sdn Bhd, a licensed natural gas and LNG importer to Malaysia under the Gas Supply (Amendment) Act, announced that it would start LNG import and gas supply operations through PETRONAS-owned receiving terminals in January 2021 (Petrolife Aero LNG, 2020). The company signed a 2-year contract with PETRONAS to send the regasified LNG to the industry sector. Earlier, Malaysia's LNG market had been dominated by PETRONAS.

In May 2022, PETRONAS signed a sales and purchase agreement with the United

States-based Venture Global LNG. The contract lasts 20 years and involves procuring 1 Mtpa of LNG from Venture Global's facility in Louisiana, United States. In June 2025, PETRONAS signed another SPA with, this time, Commonwealth LNG also for 20 years and 1 Mtpa. In the same month, PETRONAS also concluded a non-binding head of agreement with Woodside for 15 years starting in 2028, for 1 Mtpa from Woodside's portfolio. In July 2025, PETRONAS signed additional sales and purchase agreement with Venture Global for 20 years for 1 Mtpa from Venture Global's CP2 project.

2.4 The Philippines

2.4.1 Economy and Energy Outlook

The *IEEJ Outlook 2025* forecasts the Philippines' primary energy consumption to increase by an average of 2.5% per year, based on an assumed economic growth rate (at 2015 prices) of 4.7% annually from 2022 to 2050. The energy mix in 2050 will comprise 20% coal, 42% oil, 15% natural gas, 11% geothermal, 1.5% hydro, 7.4% biomass and waste, and 3.1% solar, wind, etc. (Table 2.4).

Table 0.4 Primary Energy Consumption in the Philippines

	(Mtoe)								Shares (%)		
	1980	1990	2000	2010	2022	2030	2040	2050	1990	2022	2050
Total*	22	27	39	42	63	80	107	126	100	100	100
Coal	0.3	1.3	4.6	7	19	21	26	25	4.7	30	20
Oil	10	9.7	16	14	20	29	42	52	36	32	42
Natural gas	-	-	0	3.1	2.6	5.4	11	19	-	4.2	15
Nuclear	-	-	-	-	-	-	-	-	-	-	-
Hydro	0.3	0.5	0.7	0.7	0.9	1.3	1.5	1.9	2	1.4	1.5
Geothermal	1.8	4.7	10	8.5	9	10	13	13	18	14	11
Solar, wind, etc.	-	-	-	0	0.2	2	2.9	3.8	-	0.4	3.1
Biomass and waste	9	10	7.6	8.7	11	10	9.8	9.3	39	18	7.4
Hydrogen	-	-	-	-	-	0	-	-	-	-	-

Mtoe = million tonnes of oil equivalent.
Note: * Trade of electricity and heat not shown.
Source: IEEJ (2024).

2.4.2 Natural Gas Industry and LNG Business

The Philippine Energy Plan 2023–2050 (DOE 2024) sets an indigenous natural gas production target at 0.2 Tcf/year. The government imported LNG to augment domestic natural gas supply starting in 2023.

In December 2021, the government announced its intention to invest PHP502 billion over the next 20 years in developing new gas fields to replace the Malampaya gas field (Velasco, 2021).

In November 2022, Shell completed its withdrawal from the Malampaya gas field by selling its 100% stake in Shell Philippines Exploration to Malampaya Energy XP, a subsidiary of Prime Infrastructure (Shell Global, 2022).

In May 2023, the Philippines Department of Energy announced that it had signed the Renewal Agreement for the Malampaya Service Contract (SC 38). The 25-year production contract, which was set to expire in February 2024, has been renewed until February 2039. In addition, to continuing the production operations, the SC 38 consortium is required to conduct a minimum work programme consisting of geological and geophysical studies and the drilling of at least two deep water wells during the initial renewal period from 2024 to 2029.

2.4.3 LNG-receiving Terminals

Table 2.5 shows the LNG-receiving terminals in the Philippines.

In June 2017, the country's energy minister announced the intention to make the country a hub for LNG trade in Southeast Asia, building the country's first LNG-receiving terminal and related facilities by 2020. The construction and operation of the terminal will be undertaken by the Philippine National Oil Company and others.

In September 2022, the government announced that the LNG import terminal projects of First Gen, Atlantic Gulf & Pacific Company (AG&P) of Manila, and Excelerate Energy would each begin commercial operations progressively after 2023. Shell Energy Philippines announced it will invest US$66 million to build an LNG import terminal, with construction to commence in 2024 (Offshore Technology, 2022). AG&P announced in April 2023 the arrival of the commissioning cargo for the first LNG import terminal in Batangas Bay. AG&P said that Golar Glacier and the Ish floating storage unit performed a ship-to-ship LNG transfer to cool down the floating storage unit (FSU). In June 2023, First Gen announced that it received BW Batangas floating storage and regasification unit (FSRU) in Batangas Bay. The FSRU was chartered by First Gen subsidiary FGEN LNG Corporation as part of its Interim Offshore LNG Terminal Project. FGEN LNG received the first delivery of LNG in August.

Table 0.5 LNG Projects in the Philippines

Receiving Terminal	Capacity (Mtpa)	Storage (kl)	Operation Start	Stakeholders
Philippines LNG (FSU)	5.0	137,500	2023	Atlantic Gulf & Pacific
<Phase 2>		120,000	Under Construction	
Batangas (FSRU)	3.8	162,000	2023	First Gen 80%, Tokyo Gas 20% (FSRU Owner: BW Gas)
	3.0	NA	2026 (Under Planning)	Vires Energy Corporation
	3.8	170,000	Under Planning	Shell
Pagbilao LNG	2.2	130,000	2024 (Under Construction)	Energy World Corporation
Mariveles LNG	0.2–0.4	NA	2024 (Under Construction)	Samat LNG
Cebu LNG (FSRU)	NA	NA	Under Planning	Phinma Petroleum and Geothermal (PPG)
Ilijan LNG (FSRU)	NA	NA	Under Planning	San Miguel Corporation (SMC)
Luzon LNG (FSRU)	NA	150,000	Under Planning	Excelerate Energy

FSU = floating storage unit, FSRU= floating storage and regasification unit, kl =kilolitre, LNG = liquefied natural gas, Mtpa = million tonnes per annum, NA = not available.

Source: Analysis by Institute of Energy Economics, Japan.

2.5 Viet Nam

2.5.1 Economy and Energy Demand Outlook

The *IEEJ Outlook 2025* forecasts Viet Nam's primary energy consumption to increase by an average of 3.2% per year, based on an assumed economic growth rate (at 2015 prices) of 5.4% annually from 2022 to 2050. The energy mix in 2050 will comprise 35% coal, 27% oil, 17% natural gas, 3.5% nuclear, 5.4% hydro, 6.2% biomass and waste, 5.2% solar, wind, etc. (Table 2.6).

Table 0.6 Primary Energy Consumption in Viet Nam

	(Mtoe)							Shares (%)		
	1990	2000	2010	2022	2030	2040	2050	1990	2022	2050
Total*	18	29	59	102	151	199	247	100	100	100
Coal	2.2	4.4	15	46	63	77	87	12	45	35
Oil	2.7	7.8	18	27	41	53	66	15	27	27
Natural gas	0.0	1.1	8.1	7.6	18	28	43	0.0	7.5	17
Nuclear	-	-	-	-	-	4.2	8.6	-	-	3.5
Hydro	0.5	1.3	2.4	8.2	11	12	13	2.6	8.1	5.4
Geothermal	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	0.0	3.2	7.4	11	13	-	3.2	5.2
Biomass and waste	12	14	15	9.4	11	13	15	70	9.2	6.2
Hydrogen	-	-	-	-	-0.0	-	-0.0	-	-	-0.0

	(Mtoe)							Shares (%)		
	1990	2000	2010	2022	2030	2040	2050	1990	2022	2050
Total*	18	29	59	102	151	199	247	100	100	100
Coal	2.2	4.4	15	46	63	77	87	12	45	35
Oil	2.7	7.8	18	27	41	53	66	15	27	27
Natural gas	0	1.1	8.1	7.6	18	28	43	0	7.5	17
Nuclear	-	-	-	-	-	4.2	8.6	-	-	3.5
Hydro	0.5	1.3	2.4	8.2	11	12	13	2.6	8.1	5.4

Geothermal	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	0	3.2	7.4	11	13	-	3.2	5.2
Biomass and waste	12	14	15	9.4	11	13	15	70	9.2	6.2
Hydrogen	-	-	-	-	0	-	0	-	-	0

Mtoe = million tonnes of oil equivalent.
Note: * Trade of electricity and heat not shown.
Source: IEEJ (2024).

2.5.2 Natural Gas Industry

In January 2017, the government approved the Master Plan for Vietnam Gas Industry Development to 2025, with an outlook up to 2035. The plan states that PetroVietnam and other developers should gather 17–21 Bcm of gas in 2026–2035 by collecting gas extracted from domestic fields.

In September 2019, a presentation at a symposium about the potential for developing Viet Nam's gas market indicated that being fully self-sufficient in natural gas in the 2020s would be difficult. Consequently, the country would rely on imports for 1–4 billion cubic metres per year (Bcm/y) in 2021–2025. According to the country's master plan, gas-fired power generation is expected to be 15,000 megawatts (MW) in 2025, accounting for 19% of total power generation. This capacity is expected to increase to 19,000 MW in 2030, requiring 22 Bcm of natural gas, with half of this amount expected to come from LNG imports.

2.5.3 LNG-receiving Terminals

Table 2.7 shows the LNG-receiving terminals in Viet Nam.

In July 2023, the Thị Vải LNG terminal received Viet Nam's first LNG import cargo (PV Gas, 2023). The shipment comprised 70,000 tonnes of Indonesian LNG purchased by state-run PetroVietnam Gas. From July 2023 until June 2025, the terminal received a total of 10 cargo shipments. The Thị Vải terminal has a 1 Mtpa capacity and will expand to 3 Mtpa.

Viet Nam plans to gradually phase out carbon-intensive coal power under PDP8. To help offset the shift, the plan aims for LNG to account for around 15% of its current power generation capacity by 2030, up from 0%.

Table 0.7 LNG Projects in Viet Nam

Receiving Terminal	Capacity (Mtpa)	Storage (kl)	Operation Start	Stakeholders
Thị Vải	1.0	180,000	2023	PetroVietnam Gas
(Phase 2)	2.0	180,000	2026 (Under Planning)	PetroVietnam Gas
Hai Linh	2.0-3.0	657,000	NA	Hai Linh
Bạc Liêu (FSRU)	3.0	NA	2024 (Under Planning)	Delta Offshore Energy
Khanh Hoa LNG	2.2	180,000	2030–2035 (Under Planning)	Petrolimex, ENEOS
Ca Na LNG	4.8	720,000	2024 (Under Planning)	EVN
Son My	3.0	320,000	2024 (Under Planning)	PetroVietnam Gas, AES

	(Phase 2)	3.0	NA	2027–2030 (Under Planning)	
	(Phase 3)	3.0	NA	2031–2035 (Under Planning)	
Long Son		3.5	NA	2025 (Under Planning)	GENCO3
Ca Mau		1.0	NA	2026 (Under Planning)	PV Power
Thai Binh (FSRU)		0.2-0.5	NA	2026–2030 (Under Planning)	NA
Ninh Thuan		6.0	NA	Under Planning	Gulf Energy
Thua Thien Chan May LNG		2.9	NA	2024 (Under Planning)	Chan May LNG
Cai Mep Ha		9.0	800,000	2023 (Under Planning)	T&T Group, Gen X Energy
	(Phase 2)			2026 (Under Planning)	
	(Phase 3)			2030 (Under Planning)	
Tien Lang (FSRU)		6.0	NA	2027 (Under Planning)	Exxon Mobil, JERA
	(Phase 2) (FSU)		NA	2030 (Under Planning)	
Cat Hai		NA	200,000	2025 (Under Planning)	Vingroup
Cam Pha		NA	200,000	2027 (Under Planning)	Quang Ninh LNG Power (PV Power, Colavi, Marubeni, Tokyo Gas)
Mui Ke Ga (FSRU)		NA	NA	2025 (Under Planning)	Energy Capital Vietnam (ECV), Gunvor
Long An		NA	NA	2025 (Under Planning)	VinaCapital, GS Energy
Nam Dinh		0.7	50,000	2025 (Under Planning)	JAPEX, ITECO
Hai Lang		1.5	NA	2027 (Under Construction)	T&T Group, KOGAS, KOSPO, Hanwha Energy

FSU = floating storage unit, FSRU= floating storage and regasification unit, kl = kilolitre, LNG = liquefied natural gas, Mtpa = million tonnes per annum, NA = not available.
Source Analysis by Institute of Energy Economics, Japan.

2.6 Indonesia

Indonesia, once the largest LNG supplier in the world until 2005 before the top position was taken over by Qatar in 2006, became the second LNG importer in ASEAN in 2012, following Thailand in 2011. This shift occurred because of the geographical discrepancy of its demand centre and natural gas resources. Most of its natural gas demand exists in the western part of the country such as Sumatra and Java, whilst its natural gas resource development activities are increasingly being held in the eastern part of the country.

As of August 2025, Indonesia had four conventional-scale LNG receiving terminals in operation, three of which are floating terminals and one (Arun) is onshore. These are supplemented by two small-scale terminals dedicated to domestic coastal LNG transport. The country's actual reception of LNG was 0.762 Mt from other countries and 4.9 Mt from its own LNG production plants in 2024.

2.7 Singapore

In Singapore, fossil fuel imports have been the dominant energy supply source as the country is not endowed with energy resources. Singapore started importing natural gas by pipeline from Malaysia in 1992 and from Indonesia in 2001. In the first half of the 2000s, Singapore experienced several supply disruptions from Indonesia. Even after the recovery of the supply, both Indonesia and Malaysia were considered to have limited availability of natural gas for export.

With natural gas playing an increasingly important role in power generation, the Singapore government decided in 2006 to import LNG to further diversify its gas supply. Although the plan was once suspended after the Lehman Brothers crisis in 2008, it was restarted under the strong initiative by the Singapore government, and the country started importing LNG in 2013. Singapore has been active to expand its receiving terminal facility to allow LNG bunkering and develop a more active market for LNG trading.

2.8 Myanmar

Despite achieving significant growth in natural gas production and reaching self-sufficiency by 2020, Myanmar has struggled to meet its domestic energy needs due to long-term export commitments to Thailand and China. Myanmar began exporting natural gas via pipelines to Thailand in 1999 and to China in 2013 under contracts with developers. By 2015, the country's gas production had grown sixfold compared to 2000 levels. However, this upward trend did not last, with production declining by 18% from its peak in 2019 through 2023.

The major existing offshore gas projects are Yadana Project, Yetagun Project, Shwe Project, and the Zawtika Project, with 75% of production exported to Thailand and China. The Yetagun Project ceased operation in 2021 due to depletion. Myanmar has 3,500 kilometres of natural gas pipeline length, 45 compressed natural gas (CNG) filling stations, and over

27,000 CNG vehicles.

Myanmar used to have one Thanlyin LNG floating storage unit (FSU). In May and June 2020, Myanmar received its first LNG cargoes from Malaysia. The FSU supplied LNG to an onshore regasification terminal, which fed two power plants in Yangon: 400 MW Thaketa and 350 MW Thanlyin. The LNG-to-power project was financed, constructed, and operated by CNTIC VPower, a joint venture of China National Technical Import and Export Corporation and Hong Kong's VPower Group. Myanmar has not imported LNG since 2021.

Chapter 3
The Global LNG Market Shift

3.1 Factors in the Global LNG Market Shift – from Time to Time Leading to Instability

There have been various factors leading to the ongoing fundamental shifts in the global liquefied natural gas (LNG) market. One of the fundamental changes has been the shift of demand centres from the industrialised nations, mostly represented by the Organisation for Economic Co-operation and Development countries notably in Northeast Asia and Western Europe, to more emerging economies, notably China and India, with the future trend towards the ASEAN region. Generally, prices are determined by market relationships, mainly supply and demand, under various circumstances. Traditionally the relationships have been between established LNG producers and established LNG consumers tied with point-to-point sales contracts of multiple decades.

Along with the proliferation of LNG markets into more emerging economies and LNG production projects into different countries, the traditional relationship has evolved into a more multi-point configuration of many players with different roles depending on situations in the market.

LNG production often requires significant lead times, which can create challenges when supply and demand are imbalanced If there is such imbalance, or if supply is insufficient to meet fluctuating demand, there will be a product shortage, and prices will rise. In a market where more LNG buyers have procured less volumes compared to potential demand and/or more LNG sellers have secured less offtake commitments compared to potential supply capacity, reactions to specific supply and demand situation can be amplified. Specifically, the price volatility during 2021–2022 resulted from the inability of supply increase to meet a rapid demand increase over a short period.

Specific factors of the global LNG market shift in the volatile period include:

- ✓ Long-term structural increases in gas demand, based on economic growth and resulting needs for clean and high-heating value energy sources; and persistent lack of expansion of long-term supply capacity
  - ➢ Long lead times and massive investment for LNG projects
  - ➢ Global shortages of funding sources
  - ➢ Decarbonisation uncertainty
  - ➢ Tendencies in society to hamper investment in fossil fuel development, including potential legislation and regulations to restrict those activities, as well

as movements in society to oppose fossil fuel development

- ➢ Europe's historical dependence on relatively less expensive Russian pipeline gas, which had discouraged investment in LNG projects
- ➢ Buyers' hesitations to commit large volumes of offtakings from one LNG project
- ➢ Increasing shares of spot and short-term transactions of LNG

- ✓ Short-term sudden increases in gas demand leading to a massive shift to LNG in Europe
- ✓ Chinese gas demand increased after the pandemic restrictions
- ✓ Seasonal demand fluctuations and those caused by drought and severe winter; planned and unplanned outages and unexpected troubles at LNG production plants

The following sections discuss the factors mentioned above regarding the demand and supply sides and some key factors in the global LNG market shift. Table 3.1 and Figure 3.1 show some of those factors and their interrelationships.

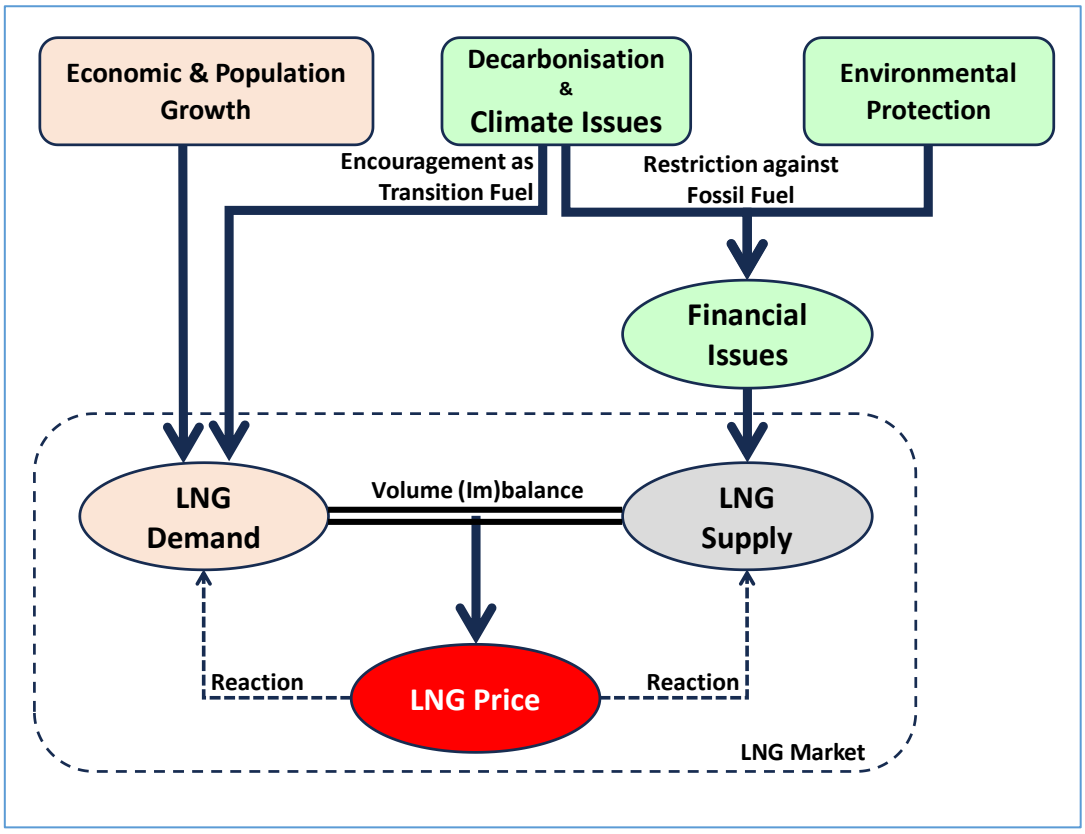
Table 0.1 Examples of Factors in the Global LNG Market Shift

	Short-term Issues	Long-term Issues
Supply issues	Feed gas shortage issues in LNG production at some projects Unplanned outages at some LNG projects LNG marine transportation restrictions at canals and channels New projects ramping up in the next 1–2 years Delays of LNG production projects under construction Declining Russian piped gas supply to Europe and increasing piped gas supply to China	Additional projects in North America Maintain stability and enable expansion of Australian LNG production Realisation of LNG projects in Africa LNG-related policies in producing countries Protection measures for domestic energy security (e.g. reform of Australian Domestic Gas Security Mechanism and the reform of Petroleum Resource Rent Tax)
Demand issues	LNG and natural gas demand recovery pace in China Nuclear developments in Japan, Korea, and France Analysis of European gas demand reduction (structural reduction due to efforts or demand destruction by higher prices) Demand fluctuation in emerging price-sensitive markets	Transition scenarios changing demand outlooks significantly Demand centres shifting to developing economies Preference for shorter long-term contracts
Price issues	Increasingly greater fluctuation of prices due to increasing volatility and increasing gas-on-gas pricing	Changing pricing arrangements in long-term contracts

Climate issues	Greater needs to enhance MRV in the LNG value chain Short-term emissions reduction measures (recovery of waste)	Clearer standards of transition-proof LNG projects and more strict environmental regulation (e.g. modified safeguard mechanism in Australia, which requests further reduction of GHG emissions, LNG export permission pause by the United States for reviewing environmental standards)
Financial issues	Diversifying channels of funding responding to the needs of LNG projects Presenting economic advantage and environmental superiority of LNG projects as investment and lending opportunities	Filling the gap between buyers' preference for flexibility and shorter duration of contracts, increasing buyer profiles including lower credit and needs to secure long-term commitment by higher rated buyers

GHG = greenhouse gas, LNG = liquefied natural gas, MRV = measurement, reporting, and validation.
Source: Analysis by Institute of Energy Economics, Japan.

Figure 0.1 Interrelationships amongst Factors Causing Price Volatility



LNG = liquefied natural gas.
Source: Analysis by Institute of Energy Economics, Japan.

3.2 Demand Side

3.2.1 Outline of Demand Side

Over the past 50 years, LNG consumption has grown faster than natural gas consumption, which, in turn, has increased faster at a higher rate than the total primary energy consumption including natural gas in the world.

In the long run, natural gas demand is expected to continue increasing, especially in developing countries, due to their economic and population growth and the resulting need for clean and high-heating value energy sources. On the other hand, some developed countries may phase out or reduce natural gas demand by around 2050 due to decarbonisation efforts and increased use of renewable energy. As a result, the centre of natural gas consumption is expected to shift from developed to developing countries that are more price-sensitive but require large amounts of heat sources.

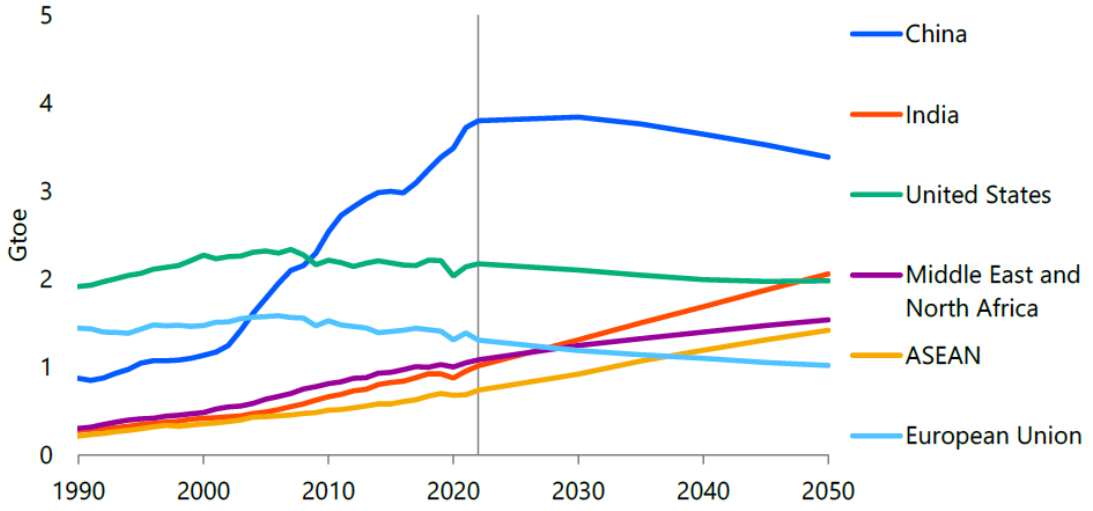
Short-term or sudden changes in circumstances may also significantly impact demand trends. For example, Europe's rapid phase-out of dependence on Russian resources, China's demand recovery caused by ending the zero-COVID policy, and expected or unexpected seasonal demand fluctuations like drought, severe winter, etc. This was clearly shown by the price volatility seen during 2023, as explained in Chapter 2.

Long-term structural increase in LNG demand

Transition scenarios are affecting demand outlooks significantly. To cope with climate change and economic growth, the role of LNG as a transition fuel is becoming increasingly important. The pursuit of carbon neutrality and net-zero emissions targets will involve transitioning from a reliance on fossil fuel for power generation to a clean energy system, with LNG playing a key role as a transition fuel. A careful look at affordability, accessibility, and energy security is needed.

The *IEEJ Outlook 2025* forecasts primary energy consumption in the ASEAN region to increase at an annual rate of 2.4% between 2022 and 2050 whilst GDP continues to grow at 4.2% per annum (Figure 3.2).

Figure 0.2 Primary Energy Consumption in Selected Countries and Regions



ASEAN = Association of Southeast Asian Nations, Gtoe = gigatonnes of oil equivalent.
Source: IEEJ (2024).

Whilst energy saving and the increased consumption and supply of renewable energy will progress, demand for natural gas will continue to rise. Natural gas, being the lowest carbon fossil fuel, will be increasingly adopted as part of climate change action. Demand for natural gas in ASEAN countries is expected to grow faster than the total energy requirement in the region. According to the *IEEJ Outlook 2025*, in the ASEAN region, despite an expansion of renewables, the share of natural gas in the energy mix is expected to expand from 19% in 2022 to 28% in 2050 (Table 3.2).

Table 0.2 Primary Energy Consumption Mix (ASEAN)

	(Mtoe)							Shares (%)		
	1990	2000	2010	2022	2030	2040	2050	1990	2022	2050
Total*	217	354	511	736	921	1,192	1,419	100	100	100
Coal	12	31	85	208	248	289	311	5.7	28	22
Oil	88	154	191	239	278	332	379	40	32	27
Natural gas	30	74	125	139	197	279	394	14	19	28
Nuclear	-	-	-	-	-	9.7	18	-	-	1.3
Hydro	2.3	4.4	6.8	19	25	29	32	1.1	2.6	2.2
Geothermal	6.6	18	25	38	69	129	142	3.1	5.1	10
Solar, wind, etc.	-	-	0	4.7	14	23	31	-	0.6	2.2
Biomass and waste	78	72	79	89	91	101	111	36	12	7.8
Hydrogen	-	-	-	-	0.1	0.1	0.1	-	-	0

Mtoe = million tonnes of oil equivalent.
Source: IEEJ (2024).

According to the *IEEJ Outlook 2025*, Asian LNG consumption will increase from 273 million tonnes (Mt) in 2021 to 490 Mt in 2050. In contract, Asian natural gas production is expected to increase from 517 billion cubic metres (Bcm) in 2021 to 825 Bcm by 2050 (+ 308 Bcm) (Table 3.3), whilst natural gas consumption in the region will grow from 859 Bcm in 2021 to 1,566 Bcm by 2050 (+ 707 Bcm) (Figure 3.3). This indicates a significant shortfall in natural gas supply, highlighting the need for increased LNG imports. Figure 3.4 shows that Asia's imports could increase significantly. The import dependency will rise from around 40% today to nearly 50% by 2050. It is, therefore, certain that ASEAN should maintain steady investment in upstream infrastructure for LNG, such as receiving terminals, pipelines, and gas-fired power generation facilities, and secure sources of LNG supply from within and outside the region. Some ASEAN Member States, even existing LNG producing and exporting countries, have started and will start importing LNG.

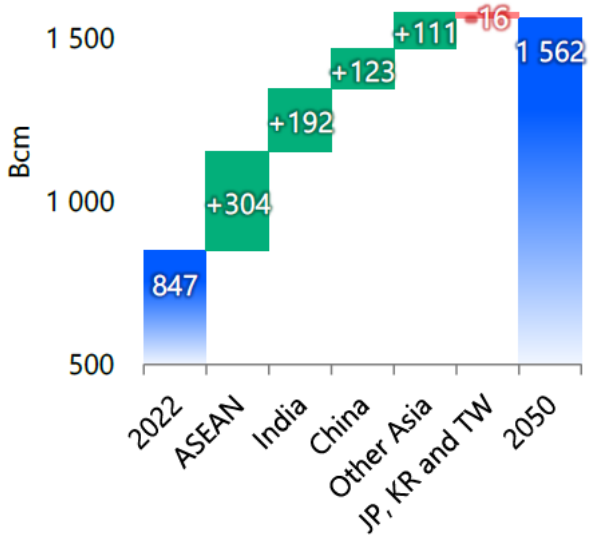
Table 0.3 Natural Gas Production

(Bcm)

	2022	2030	2040	2050	2022-2050	
					Changes	CAGR
World	4210	4364	4797	5407	1197	0.9%
North America and Mexico	1272	1337	1426	1497	225	0.6%
Latin America excluding Mexico	161	174	225	313	152	2.4%
Europe	214	143	130	100	-114	-2.7%
Europe/Central Asia	914	848	864	909	-5	0.0%
Russia	689	618	610	609	-80	-0.4%
Middle East	709	777	860	1013	304	1.3%
Africa	254	279	386	548	294	2.8%
Asia	521	642	722	823	302	1.6%
China	220	240	248	251	31	0.5%
India	34	45	71	100	66	4.0%
ASEAN	196	220	249	269	73	1.1%
Oceania	166	165	185	204	38	0.7%

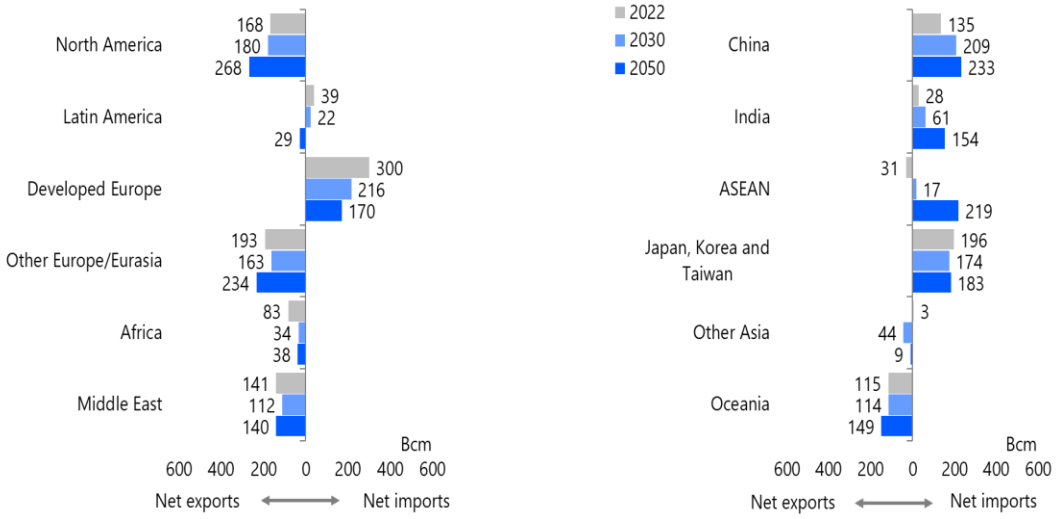
ASEAN = Association of Southeast Asian Nations, Bcm = billion cubic metres, CAGR = compound annual growth rate.
Source: IEEJ (2024).

Figure 0.3 Natural Gas Consumption



ASEAN = Association of Southeast Asian Nations, Bcm = billion cubic metres.
JP, KR, and TW stands for Japan, Korea, and Taiwan.
Source: IEEJ (2024).

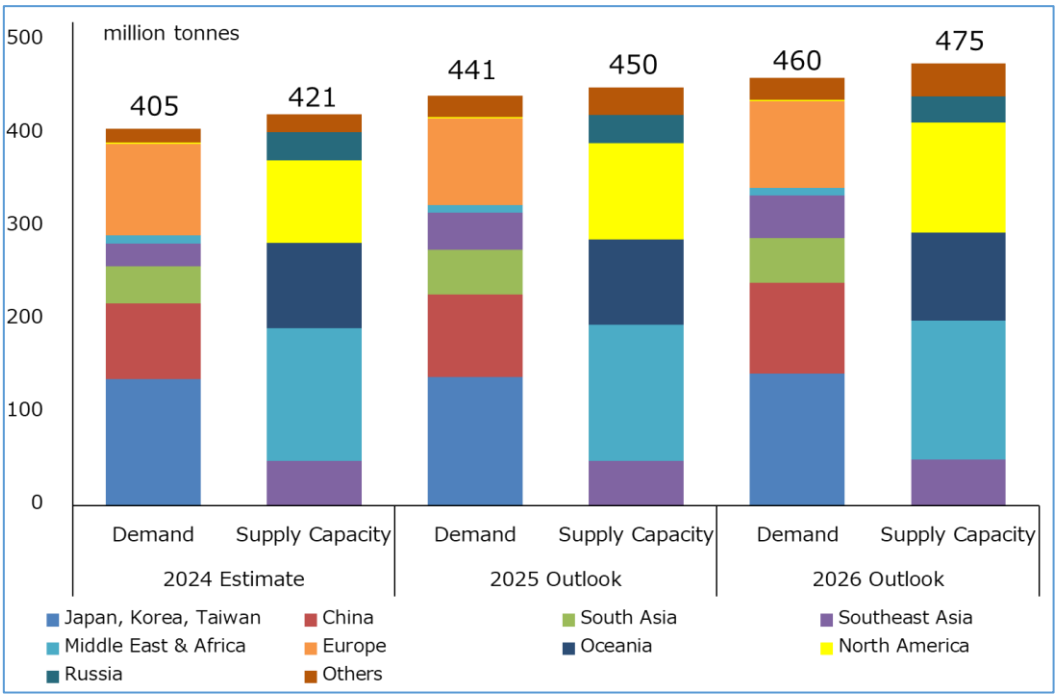
Figure 0.4 Net Exports and Imports of Natural Gas



ASEAN = Association of Southeast Asian Nations, Bcm = billion cubic metres.
Source: IEEJ (2024).

The supply–demand balance in the global LNG market is expected to remain tight until 2026. (Figure 3.5) As supply capacity has little margin, there are concerns over impediments to LNG production capacity and the impacts of international conflicts. There are uncertainties over potentially suppressed demand due to economic stagnation and high prices.

Figure 0.5 Short-term LNG Trade Outlook



LNG = liquefied natural gas.
Source: IEEJ (2024).

3.2.2 European Union: A Powerful Buyer of LNG since 2022

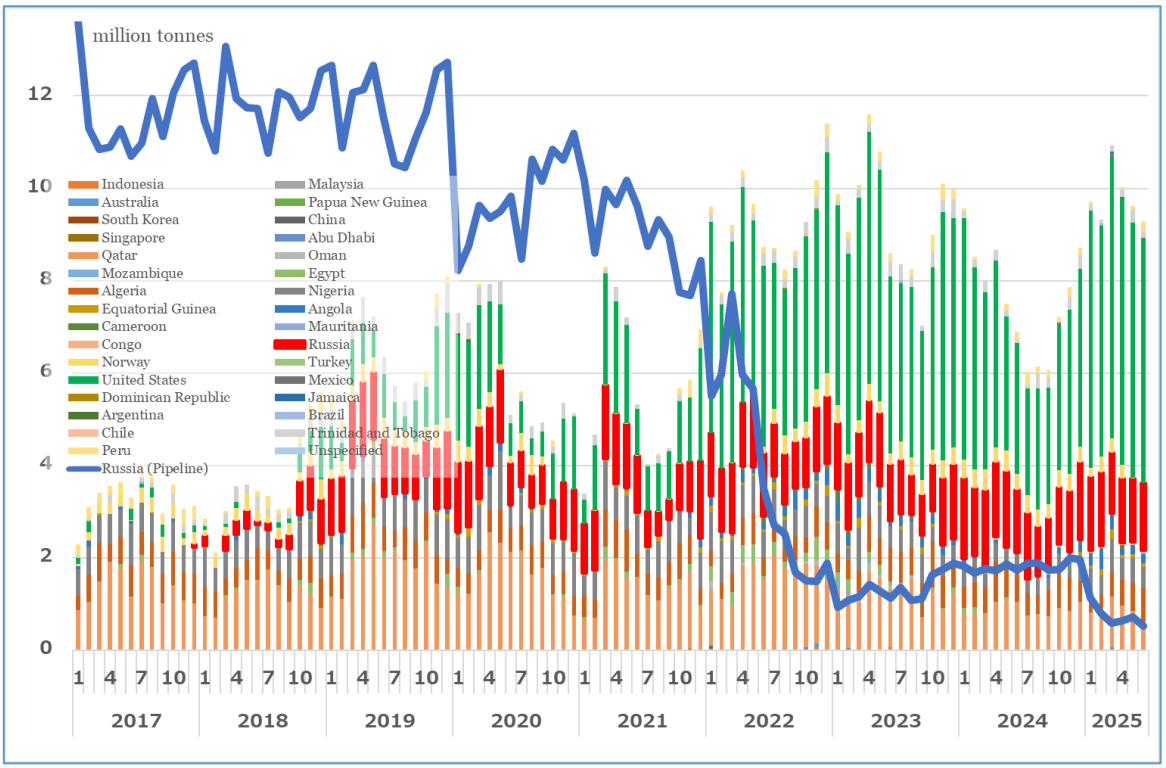
Since the Russian invasion of Ukraine in February 2022, Europe has emerged as an enormous LNG buyer with strong purchasing power. The purchasing power of Europe is expected to stay strong for at least several years, but may be phased out by around 2050 with the progress of its decarbonisation ambitions.

Previously, economic growth in Europe depended relatively on less expensive Russian pipeline gas, discouraging investment in LNG production and upstream development. But the situation has changed. Imports of Russian pipeline gas to the European Union began declining sharply in 2021, from more than 10 million tonnes per month until 2019. As Russia's use of gas supplies as a political weapon in the Russia–Ukraine war raised Europe's strong concern, Europe reduced Russia's share of total gas imports from 45% in 2021 to less than 10%. In September 2022, apparent sabotage destroyed the Nord Stream 1 pipeline connecting Russia and Germany directly under the Baltic Sea. In addition, Nord Stream 2 remains non-operational because the German government withheld its opening permission in February 2022 and its pipeline blast in September 2022. Russian pipeline gas supply to Europe expected to decrease further in 2023. As a result, LNG offtake from other parts of the world by Europe has been increasing, mainly from the United States.

Unless there are major changes in Russia's political regime or major disruptions in other countries' supply sources of natural gas and LNG, the European trend of phasing out from Russia will continue for a few years and over the medium to long term. However, the region’s current purchasing power may be reduced by around 2050 due to decarbonisation progress.

Despite broader sanctions on Russia, LNG exports from Russia have not been subject to these sanctions, so Europe has continued to import Russian LNG. The country now has two large-scale operating LNG export facilities: Yamal LNG, led by Novatek, and Sakhalin 2 LNG, led by Gazprom. These are supplemented by smaller-scale facilities, Vysotsk and Portovaya, operated by Novatek and Gazprom, respectively. France, Spain, and other EU members have been importing LNG from the Yamal project as part of their portfolio contracts. EU member countries imported around 16–17 Mt each of Russian LNG during 2022 to 2024, increasing from below 15 Mt in 2021 (Figure 3.6).

Figure 0.6 Monthly Imports of LNG and Russian Pipeline Gas to Europe



LNG = liquefied natural gas.
Note: Europe = European Union + United Kingdom.
Source: Based on data of Cedigaz LNG Services, Eurostat, Trade Stats of GB, Gazprom flow figures.

3.2.3 China: A Big Influencer of the LNG Market

China is one of the major players that will shape the global LNG market in coming years. The country was the world's largest LNG importer in 2021 and 2023, solidifying its significant presence in the international LNG market. In 2023, LNG represented 25% of China's total natural gas demand, yet natural gas accounted for 9% of the total primary energy supply. These figures suggest that, despite its increasing presence and influence in the international LNG market, LNG supplies only 2.3% of the country's total energy supply. Because of the small share, the demand for LNG in China has a significant potential.

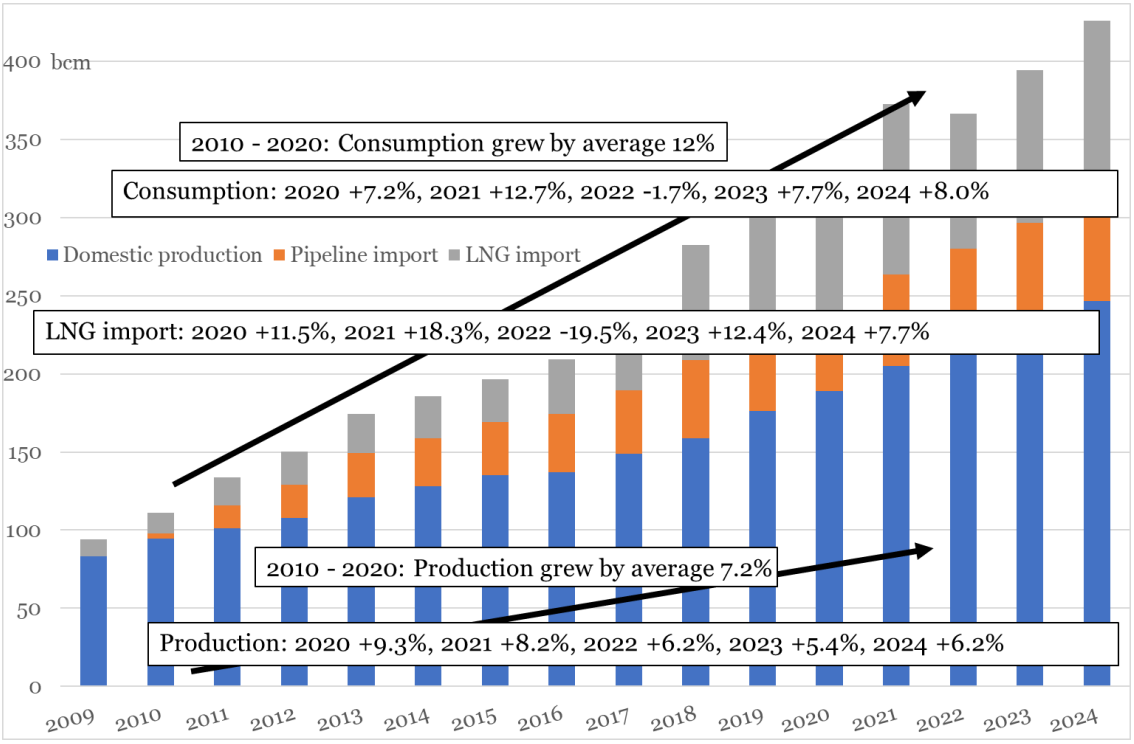
China's demand trend can easily impact the global LNG market. In 2021, China surpassed Japan in LNG imports, becoming the world's largest LNG importer for the first time. But in 2022, the COVID-19 pandemic and high LNG prices significantly reduced its LNG imports, with Japan returning to the world's largest importer. Without the decline in LNG imports in 2022, spot prices of LNG would likely have been even higher, and it might also have been difficult for Europe to secure large volumes of LNG. With its vast population, robust economy, and influential government policies, China's impact on the global supply–demand situation is substantial.

China's future LNG demand is affected by various factors. The most significant one is the country's macroeconomy. In China, natural gas is used mainly in the power and industry sectors, both of which are more influenced by economic activities than the residential or commercial sectors. Consequently, macroeconomic conditions will affect the country's natural gas demand more evidently. Energy and the environment policy are also important factors. The surge in China's LNG imports in 2016 and 2017 was largely due to the government's policy to restrict coal consumption to address the air pollution problem in northeastern parts of the country. On the other hand, the country apparently slowed LNG import offset by increasing domestic gas production, pipeline gas imports from Russia, and use of coal. The development of its natural gas resources also affects the natural gas balance of the country in the long-run and, consequently, the volume of LNG imports. China will need to develop the gas fields requiring more challenges including unconventional gas resources in the future.

Another significant uncertainty is the volume of natural gas and the timing of additional gas from Russia by pipeline. Based on an agreement made in 2014, China started receiving pipeline gas supply from Russia through an international pipeline, the Power of Siberia, in late 2019. The targeted eventual volume will be 38 Bcm per year, which is equivalent to 28 million tonnes of LNG. The plateau volume will be achieved in a few years, depending on the availability of natural gas in eastern Siberia. Depending on the buildup schedule and volumes of the Russian supply of pipeline gas, China may need to be more dependent on the spot LNG market to cover for the volume shortfall.

Between 2010 and 2024, the natural gas consumption increased nearly four times. The net imports have accounted for more than 40% of the total gas consumption since 2018 (Figure 3.7).

Figure 0.7 Demand and Breakdown of Supply Source in China, 2009–2024



Bcm = billion cubic metre, LNG = liquefied natural gas.
Source: Institute of Energy Economics, Japan analysis of data from the National Statistics Bureau.

China has abundant domestic natural gas production and import capacity through pipelines from Russia and Central Asia. As Russia seeks destinations for its natural gas, China will leverage its position as a buyer to purchase pipeline gas more cheaply. Furthermore, due to its strong government control, China has many options to respond to LNG price fluctuations. In other words, there is a significant possibility that a sharp change in LNG prices could lead to a considerable increase or decrease in China's LNG import attitude, accelerating a cycle of causing an even greater impact on the global LNG supply–demand. Indeed, China can conclude several large-scale, long-term LNG purchase contracts from a capital perspective and as a political decision of the state.

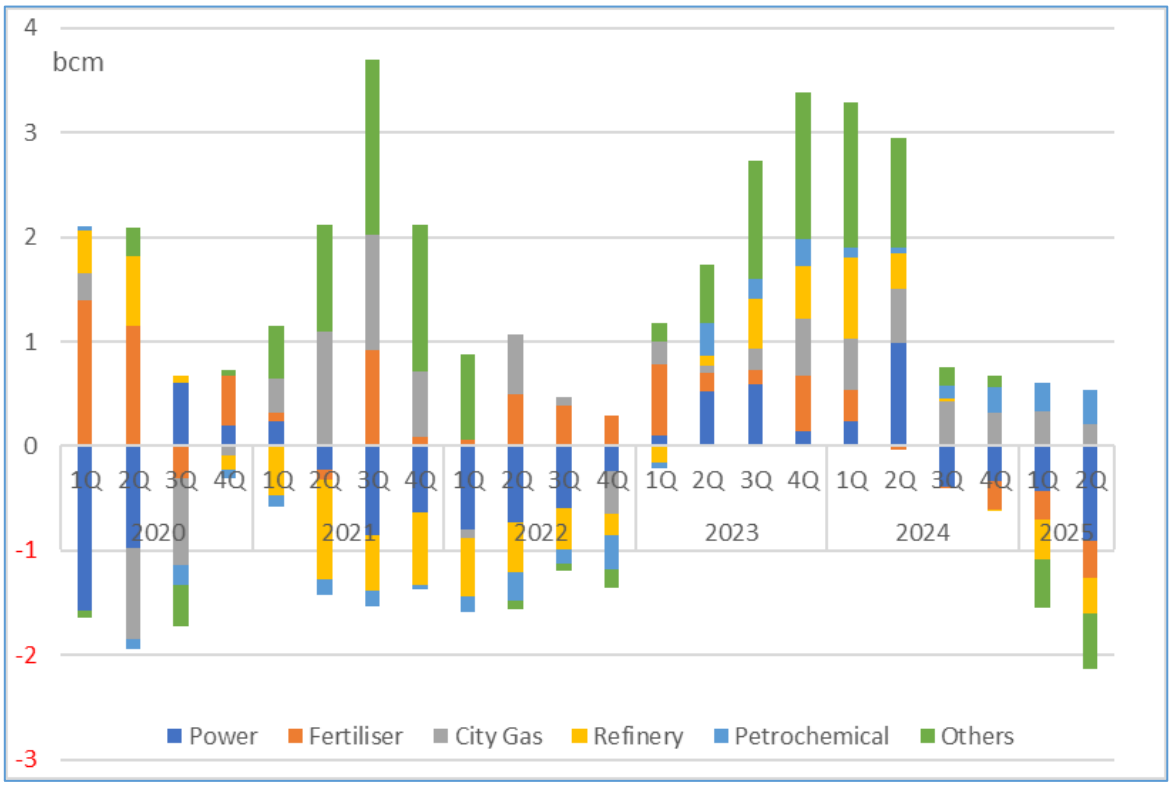
3.2.4 India and South Asia

South Asia, including India, Bangladesh, and Pakistan, reduced LNG purchases by 16% in 2022 before increasing LNG imports by 9% year-on-year in 2023 and by 3.8% year-on-year in the first half of 2024. In 2022, buyers in the region withdrew from spot markets altogether, and suppliers under long-term contracts often defaulted on cargo deliveries to obtain higher profits in other markets. Price-sensitive countries such as India, Bangladesh, and Pakistan also experienced substantial declines in LNG import volumes. Slower economic growth and switching to coal for power generation due to high LNG prices were the main reasons for demand destruction in the region.

India

With its huge population and economy, India's LNG demand significantly impacts the LNG market. India's fertiliser and city-gas sectors increased gas consumption. In 2022, overall gas consumption in the country decreased by 5.0% or 3 Bcm, with a notable decline in gas use for power generation of –24% or –2.4 Bcm. Although LNG imports and domestic gas production by the main producer, the Oil and Natural Gas Corporation, declined, private sector gas production increased by 25% or 2.1 Bcm. In 2023 and the first half of 2024, overall gas consumption in the country increased by 15.5% or 8.8 Bcm. Gas use for all the sectors increased, such as by 18.4% or 1.4 Bcm for power generation, by 7.9% or 1.5 Bcm for fertiliser, by 8.6% or 1 Bcm for city gas, by 22.6% or 0.9 Bcm for refinery. Since the second half of 2024, such trend has been changed and firstly the decline has been seen in the power sector and then in the other sectors. (Figure 3.8).

Figure 0.8 India's Gas Demand by Sector (year-on-year changes)



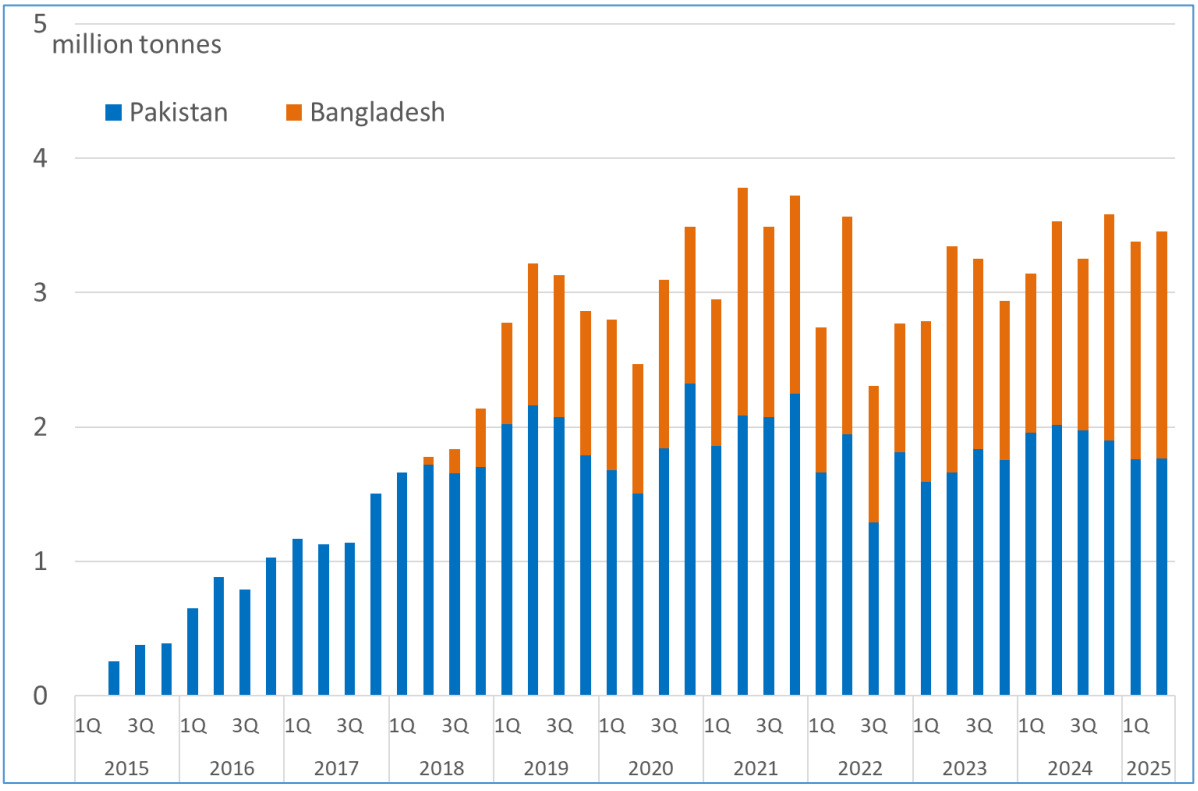
Bcm = billion cubic metre.
Note: Y axis represents year-on-year changes of quarterly gas demand by sector with the plus numbers indicating increases and the negative numbers indicating decreases.
Sources: Institute of Energy Economics, Japan analysis of data from the Ministry of Petroleum and Natural Gas of India.

Bangladesh and Pakistan

Regarding LNG procurement, there has been a relatively sharp contrast between Southeast Asia and two South Asian countries – Bangladesh and Pakistan. Whilst ASEAN Member States increased LNG imports by 2.5 Mt in 2022, Bangladesh and Pakistan lost almost the same amount, with signs of more difficulties in procurement (Figure 3.9 and Figure 3.10). Bangladesh and Pakistan sometimes suffer from electricity shortages, planned or effectively forced blackouts, and a vicious cycle of poor electricity supply, further weakening the poor economy. This shows an excellent example of how extremely high LNG prices can impact relatively weaker economies in Asia.

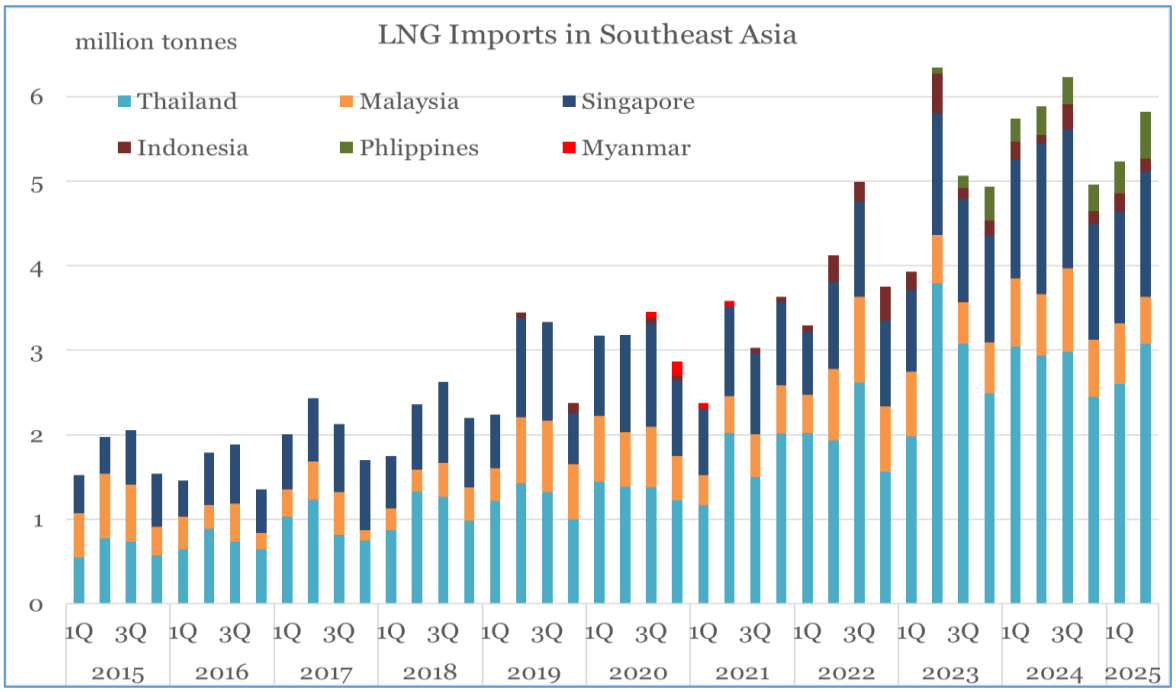
If a country has a lower credit rating, it is difficult for an LNG importer in such a country to secure a long-term LNG purchase contract and secure LNG cargo in the spot market.

Figure 0.9 LNG Imports by Bangladesh and Pakistan



LNG = liquefied natural gas.
Source: Based on Cedigaz and trade statistics of various countries.

Figure 0.10 LNG Imports by Southeast Asian Countries



LNG = liquefied natural gas.
Source: Based on Cedigaz and trade statistics of various countries.

3.3 Supply Side

3.3.1 Outline of Supply Side

It is impossible to produce LNG beyond contracted capacities during normal times nor to expand supply capacity in a short period. Long lead times and significant capital investment are required before an LNG production site becomes operational. In other words, it is difficult to expand or change supply capacity elastically in response to fluctuations in demand.

For instance, buyers nowadays want to diversify their portfolio and prefer to take 1 or 2 Mt per year from a specific project. LNG buyers hesitate to commit large volumes of off-takings from a single LNG project, leading to slower LNG production development and delaying final investment decisions (FIDs).

Europe's dependence on Russian pipeline gas hindered seeking other natural gas sources, which might be more expensive.

Furthermore, planned, and unplanned outages and unexpected troubles at LNG production sites occur occasionally, also causing impacts on supply trends.

In addition, especially since 2023, choke point risks are currently emerging as serious issues such as the Panama Canal due to its lower water level and the Suez Canal due to political tensions. As the International Energy Agency also points out in its *Gas Market*

Report (Q3 2025), the shipping constraints due to these choke point risks could increase LNG supply costs, which would diminish flexibility and affordability of LNG supply to Asia as well.

3.3.2 Impact of Decarbonisation

Decarbonisation efforts are expected to be costly and are always deemed more expensive than not decarbonising. The decarbonisation impact contributes to the reluctance to increase upstream investment. It is challenging to extract funding sources to meet the massive financing needs for decarbonising various sites worldwide. Decarbonisation uncertainty – whether economies have to decarbonise, when to complete it, to what extent, etc. – has made companies prefer short-term commodity procurement to upstream investment, which would bind capital for extended periods. Besides, today's society strongly tends to hamper and oppose investment in fossil fuel development, sometimes including potential legislation and regulations to restrict those activities. Coal divestment by international financial institutions and those in developed countries is now an irreversible trend. There are also signs of caution towards natural gas, although such signs have somewhat receded since dealing with the recent tight gas supply–demand balance. If natural gas divestment becomes a decisive trend as top priority is placed on climate action again, Asia's energy transition and energy security will become more costly, potentially weakening its relative economic power.

3.3.3 Selected Examples of Factors Causing Expansion or Shortage of LNG Supply

Several elements can positively or negatively impact global LNG supply. Here are some of those factors, the effects of which will last for some time or longer. For instance, examples include additional projects or expansion of existing projects in North America, maintenance of stability and production increases in Australia, the realisation of a vast number of deep-sea projects in Africa, and rising issues of regulations and strict policies on development projects. Figure 3.11 is a brief recap of the factors.

Middle East

- ✓ Qatar
  - ➢ Significant expansion (North Field East and North Field South) projects are expected from 2026 onwards. Additional expansion (North Field West) has also been announced in 2024. Total expansion volume is expected to be 64 Mtpa, bringing Qatar production volume to 142 Mtpa by 2030.
  - ➢ Major international companies, including western major corporations and Chinese biggest companies have joined the projects.
  - ➢ Significant volumes are expected to be offered on a term basis, for as long as 27 years, extending into the 2050s.

- ✓ Iran
  - ➢ Huge gas resources have been prevented from development due to sanctions.
  - ➢ Russia and China pursue deeper cooperation with Iran, including LNG projects.
- ✓ Eastern Mediterranean Nations
  - ➢ Israel, Egypt, and the EU agreed to increase LNG exports from Egypt in June 2022.
  - ➢ There has been an idea to lay a subsea pipeline between Israel and Türkiye.

Asia–Pacific

- ✓ Australia
  - ➢ Several LNG-related legislative reforms entered into force in 2023, potentially increasing burdens on LNG projects.
  - ➢ LNG project promoters are concerned about the actual impacts of these reforms, which need further clarification.

Americas

- ✓ Canada
  - ➢ The government promotes investment towards the electrification of gas fields and LNG facilities and business opportunities for decarbonisation.
  - ➢ LNG Canada, an LNG export project shipped its first cargo in June 2025.
- ✓ United States
  - ➢ After Freeport LNG returned to full operation, the United States became the world's largest LNG exporter in 2023.
  - ➢ More long-term offtake commitments have been made, and further deals are expected to facilitate investment decisions.
  - ➢ The government promotes investment towards electrifying gas fields and LNG facilities.
  - ➢ The government ended the 1-year pause of LNG export permits to non-free trade agreement (FTA) countries in January 2025.
- ✓ Mexico
  - ➢ New Fortress Energy achieved its first LNG production from the Altamira floating LNG (FLNG) facility in July 2024 (New Fortress Energy, 2024).
  - ➢ The Energia Costa Azul project on the west coast is expected to start LNG exports in 2026.

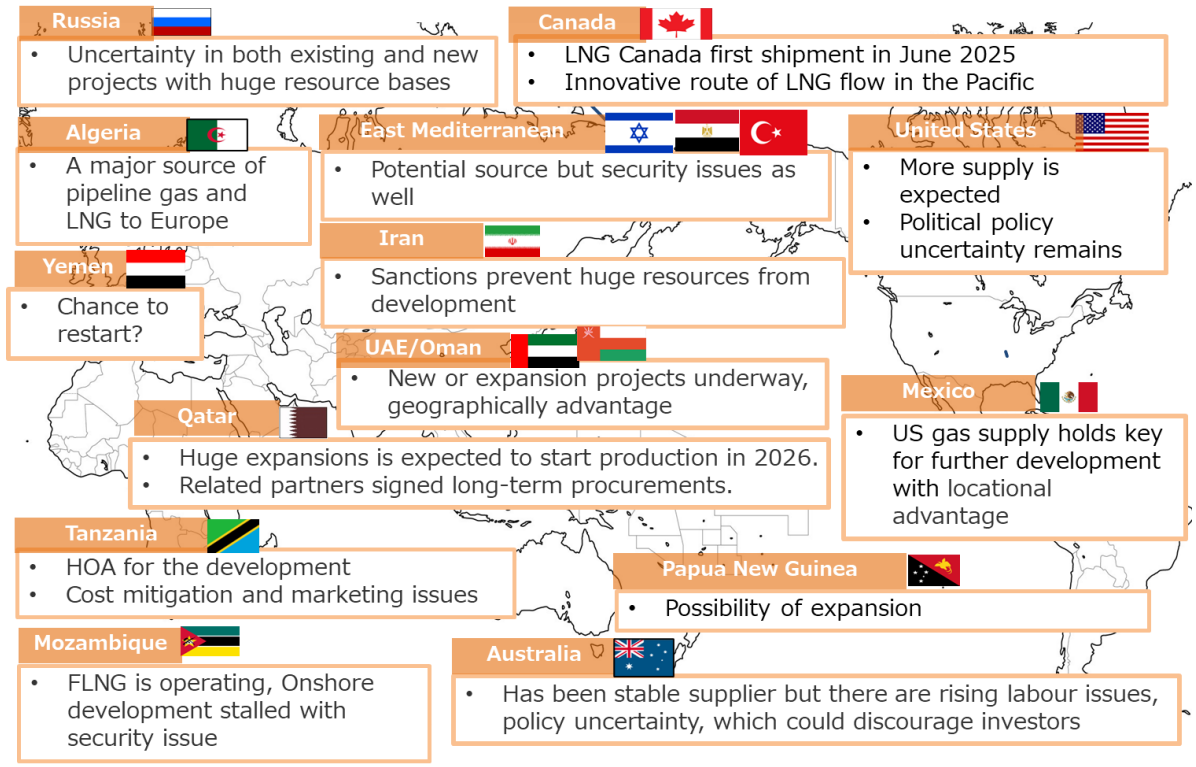
Europe

- ✓ Russia
  - ➢ Uncertainty over new LNG production projects due to sanctions.
  - ➢ Possibility of unexpected interruptions in LNG supply.

Africa

- ✓ Algeria
  - ➢ Exports to Europe increasing since 2022.
  - ➢ Political tussles with Morocco, leading to curtailment of gas supply.
- ✓ Tanzania
  - ➢ International partners agreeing with the government over the LNG export project.
- ✓ Mozambique
  - ➢ Coral South FLNG facility in LNG export operation since November 2022.
  - ➢ Mozambique LNG 1 (land-based) construction has been suspended since April 2021.

Figure 0.11 Examples of Factors to be Considered on the Supply Side



FLNG = floating liquefied natural gas, HOA = head of agreement, LNG = liquefied natural gas, UAE = United Arab Emirates, US = United States.
Source: Analysis by Institute of Energy Economics, Japan.

3.3.4 Selected Occasional Supply Disruptions

Since 2020, there have been outages at many supply facilities worldwide, significantly impacting LNG spot markets and prices for a short period. Such cases occur occasionally, planned, or unplanned. Figure 3.11 is a brief recap of the factors.

Asia-Pacific

- ✓ Australia
  - ➢ Gorgon and Wheatstone – labour disputes culminated in industrial action posing uncertainty over supply in September 2023, although actual disruption was minimal.
  - ➢ Prelude – the floating LNG production facility was shut down for an investigation by the Australian Maritime Safety Authority after a fire in December 2021, resuming operations only in May 2022. It was followed by a labour dispute affecting LNG shipments in July 2022.
  - ➢ North West Shelf Train 2 was permanently shut down in the first half of 2025, due to declining gas supply from the existing gas fields.
- ✓ Indonesia
  - ➢ Tangguh – the construction of LNG facility Train 3 was delayed due to COVID-19 by more than 1 year.
- ✓ Malaysia
  - ➢ MLNG – production at the Bintulu LNG facility experiencing a shortage of feed gas from some gas fields in the latter half of 2021. A force majeure notice of some LNG shipments to LNG buyers was issued in October 2022 due to a failure at one of the pipelines to deliver gas to the plant, although the actual impacts were limited.
- ✓ Peru
  - ➢ Peru LNG –interruption of LNG production for 4 months in 2021.
- ✓ Russia
  - ➢ Sakhalin 2 – there has been uncertainty over its operation after the unilateral strengthening of Russian control of the project in 2022, along with the uncertainty about project engineering integrity after 2022.

Americas

- ✓ Trinidad and Tobago
  - ➢ Atlantic LNG – one of the three LNG production trains has been shut down since mid-2021 for an indefinite period due to a shortage of feed gas.
- ✓ United States
  - ➢ Calcasieu Pass LNG – failures in power generation and heat recovery steam generator units in March 2023.
  - ➢ Freeport LNG – a fire incident in June 2022 suspended operation for 9 months.

Europe

- ✓ Norway
  - ➢ Hammerfest LNG –suspension of LNG production from September 2020 to June 2022 after a fire.

Africa

- ✓ Algeria
  - ➢ Skikda LNG – temporary shutdown of Train 1 for 1 month in 2021.
- ✓ Egypt
  - ➢ Shortage of gas for LNG production turning the country into a net LNG importer again in 2024.
- ✓ Equatorial Guinea
  - ➢ EGLNG –suspension of LNG production due to an interruption in the supply of feed gas for 1 month in 2021.
- ✓ Nigeria
  - ➢ NLNG – LNG production fell by 20% during 2021 due to a shortage of feed gas. The Train 7 project has faced delays due to flood and terrorists destroying the pipeline, with commencement of production expected around 2025.

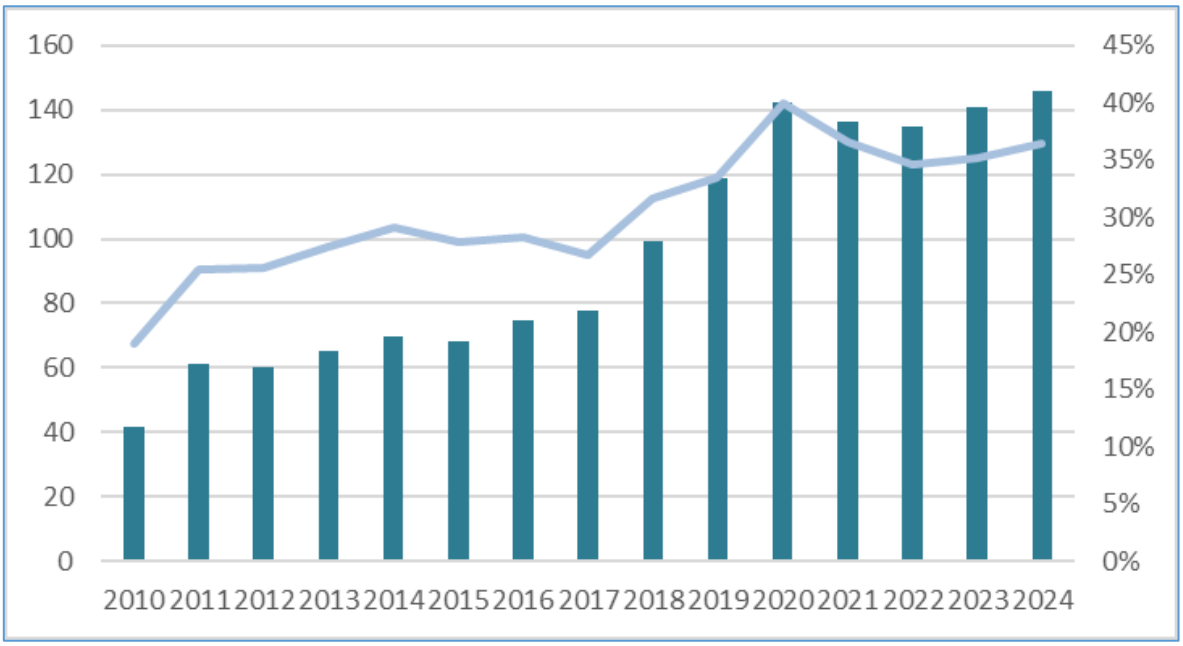
3.4 Evolving Ways of LNG Transactions

3.4.1 Increasing Spot and Short-term Transactions

Due to the political and regulatory demands for decarbonisation and the need of a more effective procurement portfolio, some buyers – both in mature and emerging markets – are unwilling to make commitments to purchase LNG for 15–20 years. As a result, spot and short-term transactions have been increasing in recent years, which has resulted in higher volatility of spot LNG prices. In other words, the more dependent you are on spot transactions, the more you are affected by spot price changes.

According to the *GIIGNL Annual Report 2024*, the world's LNG-consuming markets imported 401 Mt in 2024, with 146 Mt (36%) of which was imported on a spot or short-term basis (Figure 3.12).

Figure 0.12 Share of Spot and Short-term vs Total LNG Trade (Mtpa/%)



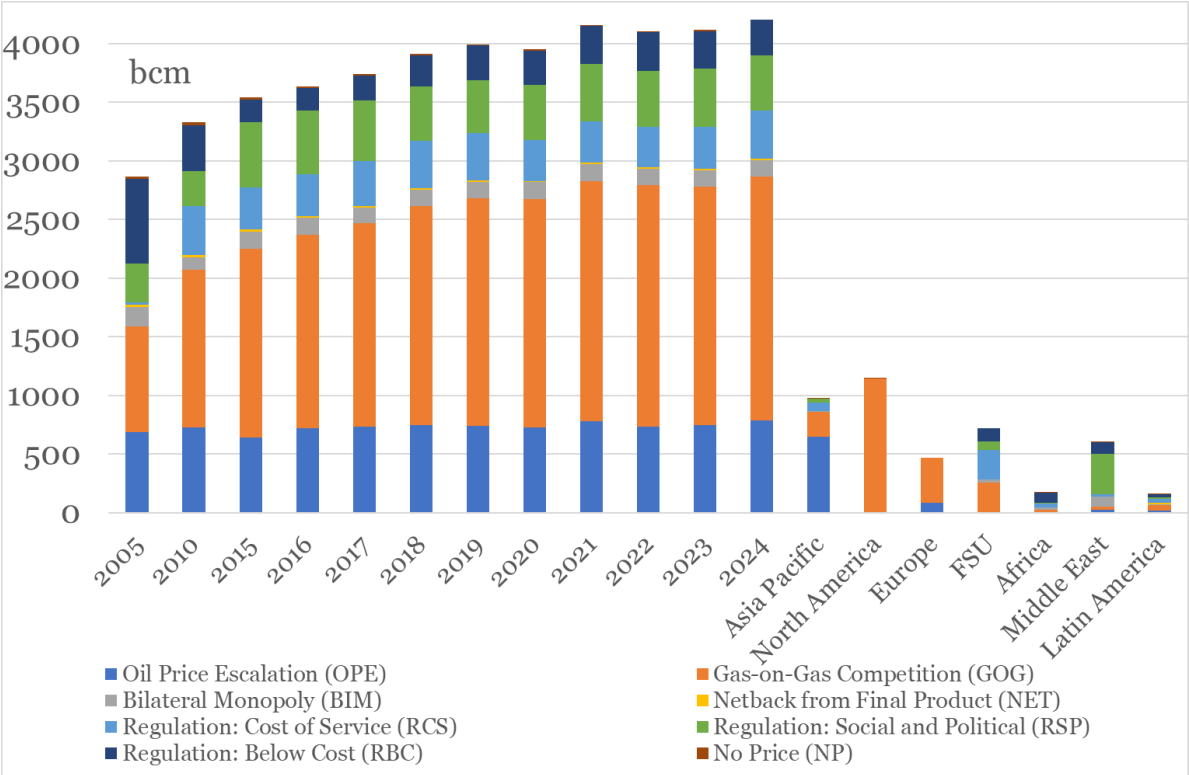
LNG = liquefied natural gas, Mtpa = million tonnes per annum.
Note: The line shows the share of spot and short-term LNG, whilst the bars show the volume of spot and short-term LNG trade.
Source: GIIGNL (2025).

3.4.2. Wholesale and Imported Gas Prices Are Set Differently

Changes in pricing arrangements for long-term contracts and greater fluctuation of prices due to increasing volatility and increasing gas-on-gas pricing have been observed.

On a global basis, more gas has been priced through gas-on-gas competition. In the Asia-Pacific region, more gas is priced out of oil prices. The increasing inflow of LNG from the US has pushed the diversification of gas prices in different regions. Interactions with other global regions cause more significant fluctuations in regional gas prices (Figure 3.13).

Figure 0.13 Gas Pricing Mechanism



Bcm = billion cubic metres, FSU = Former Soviet Union
Source: Based on IGU (2022).

3.4.3. Balancing Between Needs of Flexibility and Long-term Commitment

The industry needs to fill the gap between buyers' preferences for flexibility and shorter duration of contracts and sellers' requirements to secure long-term offtake commitments before making investment decisions, thereby stabilising the LNG market on a mid-to-long-term basis. Especially, increasing buyer profiles, including lower credit, requires project developers to secure certain amounts of long-term commitment from higher-rated buyers.

To secure funding for more LNG production projects, presenting the economic advantage and environmental superiority of LNG projects as investment and lending opportunities will be more important. This will also accompany the need for some measures to make clean LNG even cleaner:

- Clearer standards of transition-proof and cleaner LNG projects
- Greater need to enhance measurement, reporting, and verification (MRV) (or MMRV, if monitoring is added as a requirement) of GHG emissions in the LNG value chain
- Short-term emissions reduction measures (recovery of wasted gas, for example)

Chapter 4.
LNG Policy Shift in the United States and its Possible Impact on the Asian LNG Market

4.1 Outline and Characteristics of LNG from the United States

Liquefied natural gas (LNG) represents more than just a fuel source, particularly when it comes to the United States (US) and Asia. LNG can reduce particulate and carbon emissions, promote economic prosperity, and energy security for the United States and its Asian trading partners. Today, it represents both a cost-effective strategy to address near-term climate concerns and energy security risks.

The pursuit of carbon neutrality (or, more broadly, greenhouse gas [GHG] neutrality) and net-zero emissions in the Association of Southeast Asian Nations (ASEAN) will rely on transitioning from fossil fuel to cleaner energy. The increasing source of LNG supply from the US is important for energy security in the region. Expanding LNG use will have good implications for energy security and the environment. Then, it will be a key policy direction for the region to strengthen energy security in the Asia-Pacific and strengthen ties with the United States.

The US has become the world's largest producer and exporter of natural gas, and with that role comes responsibility. The country says it will maintain its energy security commitments to its overseas allies and partners as they confront growing demand, constrained supply, and increased price volatility. In 2023 and 2024, LNG exports from the US reached 84.5 and 85.4 million tonnes (on delivered basis in importing economies), respectively, the highest ever annual exported volume from one LNG exporting country for 2 years in a row, representing more than one-fifth of all LNG exports globally. When all current LNG projects in the US are complete later this decade, LNG exporting capacity from the US will be roughly 180 million tonnes per year, a little more than double the current levels. The US administration has authorised exports of 350 million tonnes per annum (Mtpa), four times the current LNG production and export levels in the country, although there could be concern over a future policy change, which had been seen in the temporarily halt of export authorisation in 2024.

Key Characteristics of LNG from the United States for Customers

1) Affordable – reasonable price, at least at the free on board (FOB) point
2) Clean – possibly near-zero carbon LNG
3) Reliable
   – the shale revolution, a resource to produce for the next 30 years or longer
   – produced by thousands of operators driven by market forces

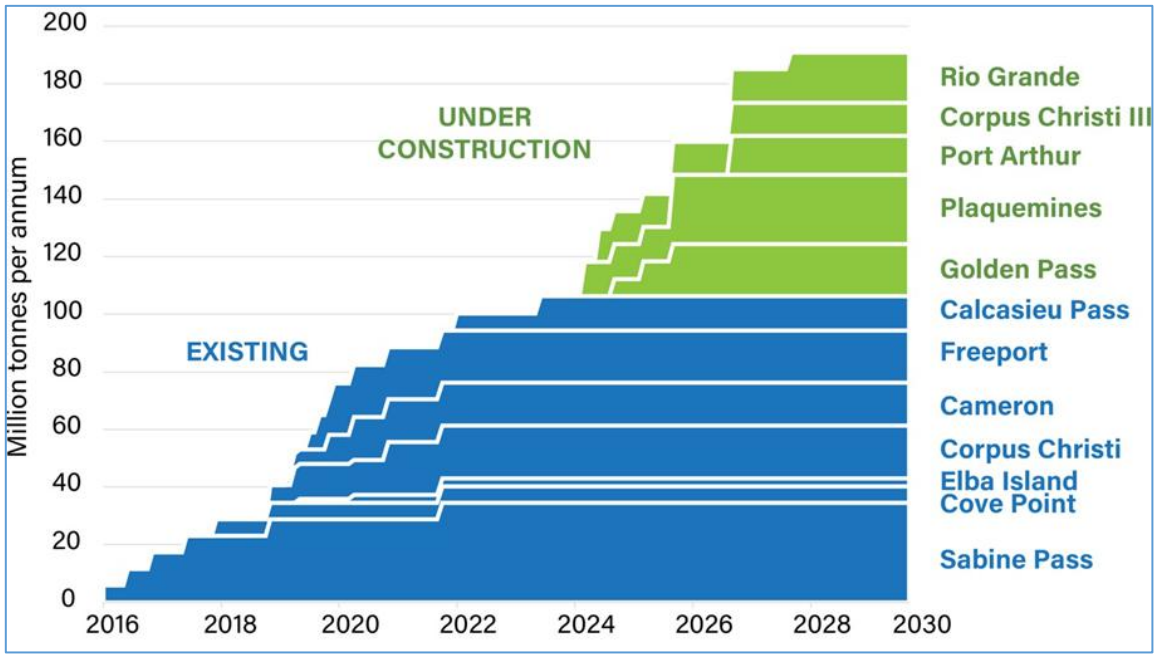
4.2 Volume of LNG from the United States

The US boasts a total LNG liquefaction nameplate capacity of 102.6 Mtpa, compared with Qatar's 77 Mtpa and Australia's 90+ Mtpa. This amount is equivalent to approximately 140 billion cubic metres of natural gas per year, or a little over one-fifth of global LNG liquefaction capacity in 2024. Given that the first US exporting terminal came online in 2016, the pace and scale of investment poured into LNG infrastructure is unprecedented.

Since the first FID for Sabine Pass back in 2012, US LNG developers have spent approximately US$135 billion for existing and under-construction terminals, based on various industry sources. In addition to the export facilities, US companies spent billions of dollars to support the LNG supply chain through investments in upstream and midstream.

According to data from the Energy Information Administration (EIA), the LNG export infrastructure capacity is projected to double by 2030. The terminals under construction could add another 80 Mtpa by the end of this decade. To meet long-term global LNG demand, the US needs to ramp up its infrastructure further by eliminating political obstacles to new LNG terminals (Figure 4.1).

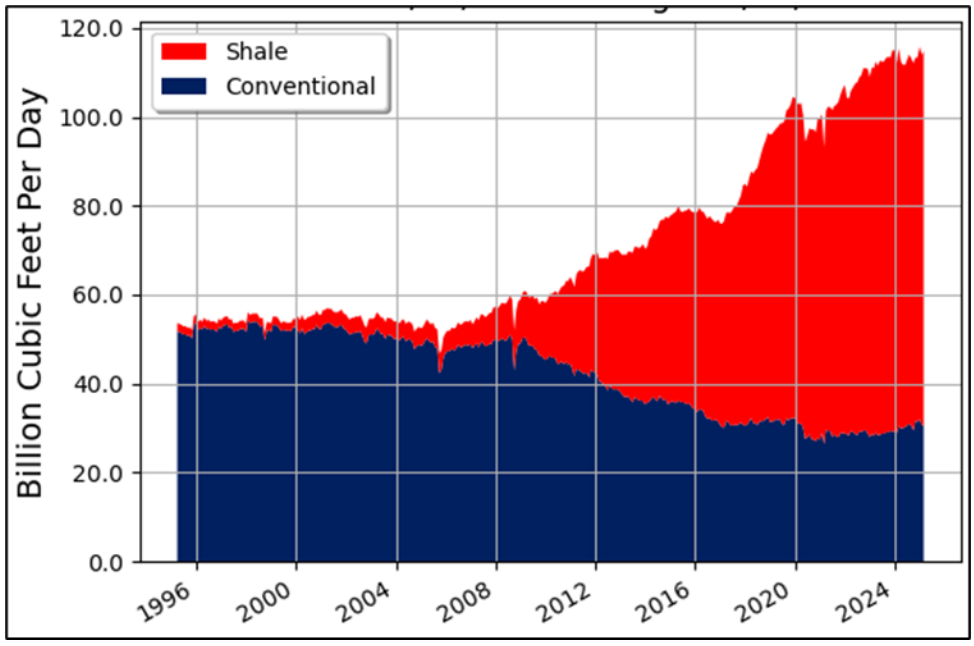
Figure 0.1 Existing and Under Construction LNG Export Terminals in the United States



LNG = liquefied natural gas.
Source: Energy Policy Research Foundation Inc, analysis from Energy Information Administration data.

The US' resource base does not limit the capacity to expand natural gas and LNG exports (Figure 4.2).

Figure 0.2 Monthly Natural Gas Production – Conventional vs Shale, United States (Bcf/d)

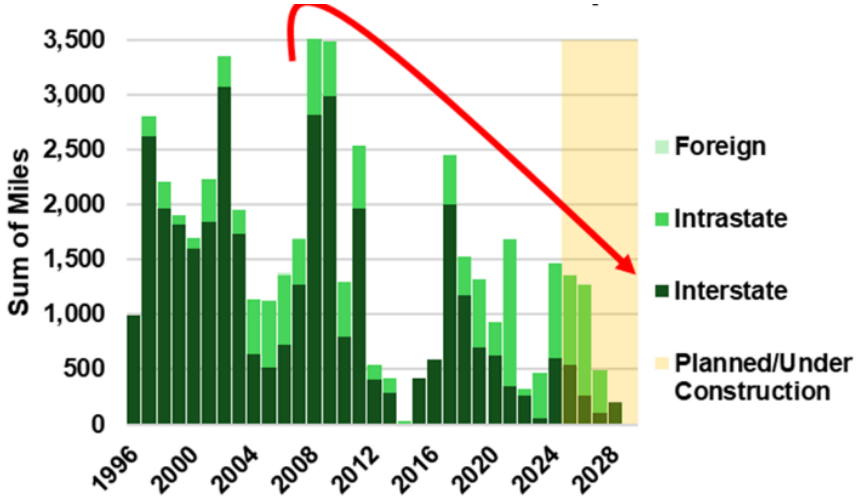


Bcf/d = billion cubic feet per day.
Source: Energy Policy Research Foundation analysis from Energy Information Administration data.

Future natural gas supplies from the US to partners in worldwide markets depend entirely on the capability to build sufficient pipeline infrastructure and development of market demand to support the construction of new LNG export facilities.

With the 2000s surge in US hydrocarbon production, US producers sped to add needed natural gas pipeline capacity. Natural gas pipeline additions peaked at 3,600 miles (5,800 kilometres) in 2008. Subsequently, there were secondary peaks in the late 2010s (Figure 4.3).

Figure 0.3 Miles of Natural Gas Pipelines Added, United States



Source: Energy Policy Research Foundation Inc, analysis from Energy Information Administration data.

Since then, the combination of setbacks from the COVID-19 pandemic coupled with more restrictive permitting has led to a curtailment in new capacity. Currently, projections up to 2030 show minimal planned and/or under construction additions.

But with the expansion in expected power demand and the potential for liquids export growth, additional capacity will be required. In a 2024 report, the Grid Modernization Initiative projected 128 gigawatts of new electricity generation would be needed by 2030 in response to the accelerating power needs from data centres (US Department of Energy, 2024). The fastest way to deliver this generation would be through the commissioning of natural gas plants.

In addition, there is currently another 0.283 bcm/d of new LNG capacity under construction set to be commissioned by 2030. Without additional pipelines, shortfalls are expected, leading to power curtailments. Even with enough pipeline capacity, the expected growth in power demand may cause more gas to be used domestically, and less available for transport. Current consensus is that to meet rising data centre demand driven by artificial intelligence, the only near-term power option is large-scale construction of combined cycle gas plants. If the US does not match this increase in demand with an increase in gas production, the lack of diversity in the near-term power mix could become a threat worldwide to energy security as one of the most liquid and reliable forms of energy (US LNG) is reduced or taken off the global market.

4.3 Current and Historical LNG Export Trends

4.3.1 Outline of LNG Exports from the United States

The US is fully integrated into the North American natural gas market, where natural gas flows without major obstacles across the borders with Canada and Mexico through pipelines. Table 4.1 shows that the United States continues to import large volumes of natural gas from Canada and export large volumes of natural gas to Mexico..

Table 0.1 United States' Natural Gas Production, Imports, and Exports, 2022–2024

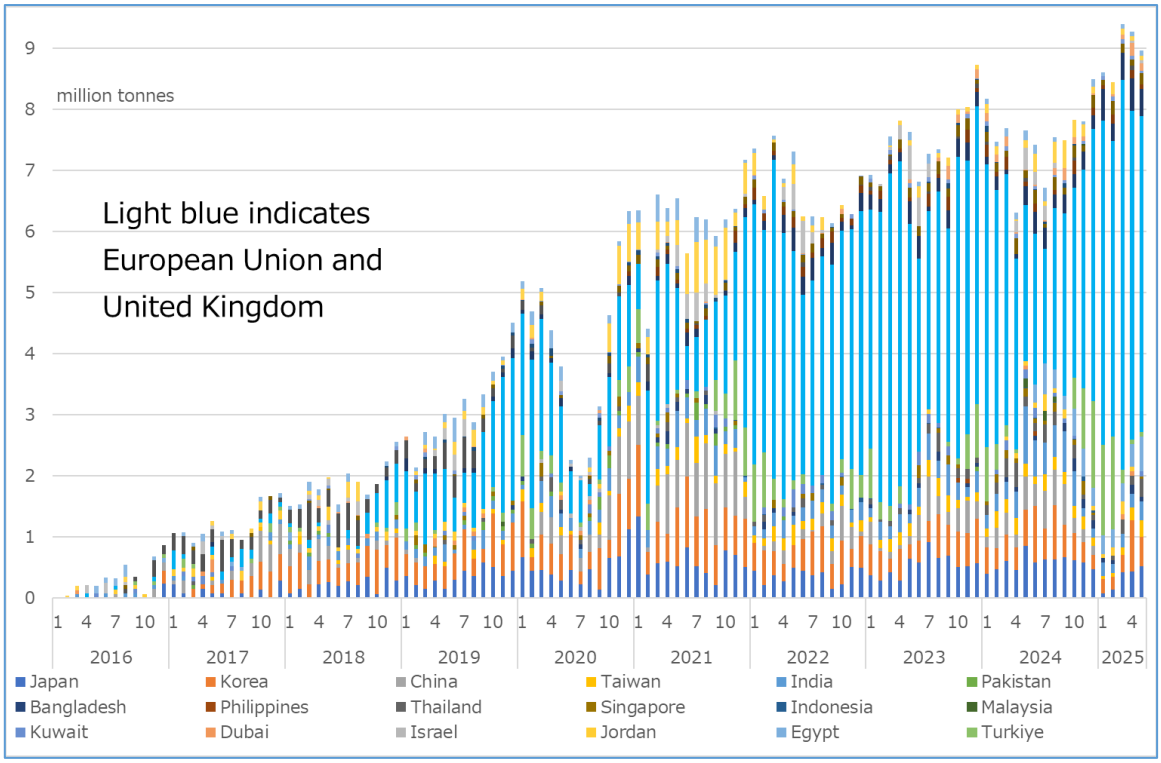
Category	CY 2022	CY 2023	CY 2024	CY 2025	CY 2026P
Dry Gas Production (Bcf/d)	99.3	103.6	103.2	104.9	106.4
LNG Imports (Bcf/d)	0.1	0.0	0.0	0.0	0.1
LNG Exports (Bcf/d)	10.6	11.9	11.9	14.6	16.0
Pipeline Gas Imports (Bcf/d)	8.2	8.0	8.5	8.9	8.9
Pipeline Gas Exports (Bcf/d)	8.3	8.9	9.1	9.9	10.5
Other (Bcf/d)	-1.0	0.1	-0.2	0.8	1.5
Total Supply (Bcf/d)	87.7	90.9	90.5	90.2	90.3
Total Total Demand(Bcf/d)	88.5	89.4	90.5	31.3	90.7
Working Gas Storage Change (Bcf)	-285	532	-18	-400	-151

Bcf/d = billion cubic feet per day, CY = calendar year, LNG = liquefied natural gas.
Source Energy Policy Research Foundation analysis from Energy Information Administration data.

Regarding LNG exports, around 60% of LNG from the US was directed to Europe in 2022 and 2023, reflecting lower transportation costs and rising values due to the Russian invasion of Ukraine and the loss of Russian supplies to the European continent. Whilst in 2024, the portion directed to Europe declined to around 50%, but it still remains the main destination of LNG from the US. Whilst the portion directed to Asia was nearly 50% in 2021 before the Ukraine crisis, it declined to below 30% in 2022 and 2023, and slightly increased to around 30% in 2024 (Figure 4.4).

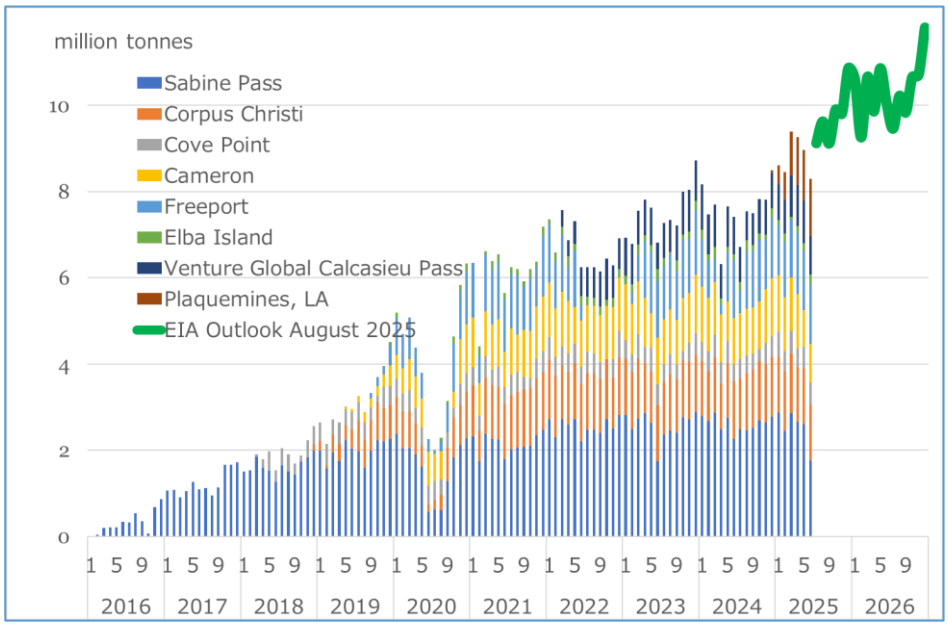
As shown in Figure 4.5, the volume of LNG exports from the US has been increasing and is expected to continue to increase along with the start of new projects.

Figure 0.4 LNG Exports from the United States by Destination, 2016–2025



Source: Compiled based on data from the US Department of Energy.

Figure 0.5 LNG Exports from the United States by Project

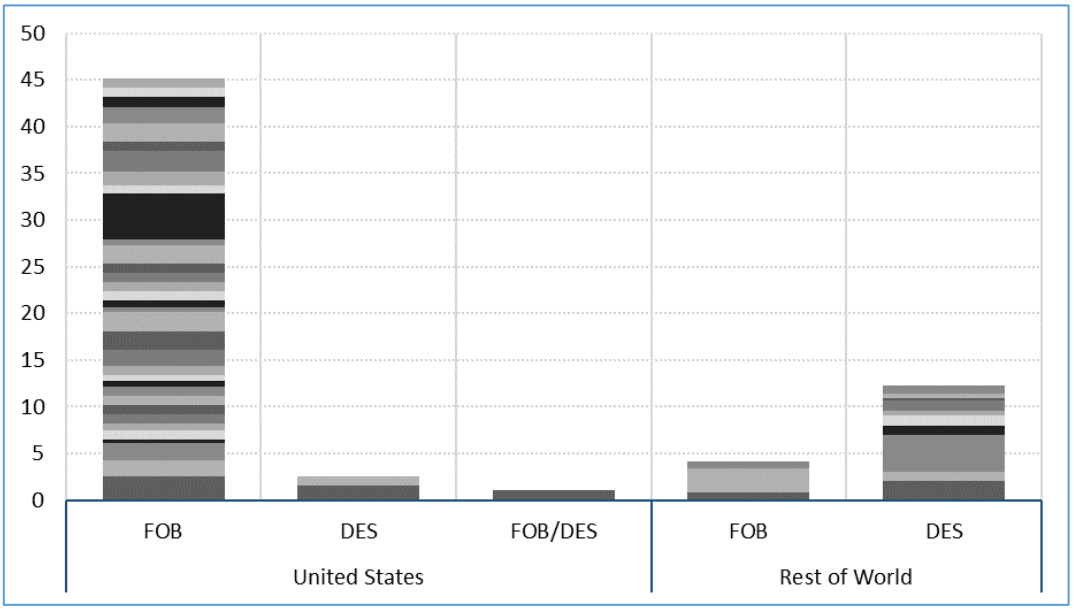


EIA = Energy Information Administration, LNG = liquefied natural gas.
Source: Compiled based on data from the US Department of Energy and Energy Information Administration.

4.3.2 Destination-free Clause

Most LNG contracts originating from the US do not restrict LNG cargo destinations under free-on-board (FOB) transactions, allowing importers to reroute or resell LNG purchased from the US. This is an improvement over the traditionally more dominant delivered ex-ship (DES) contracts. With more LNG project promotors in the US signing long-term contracts in recent years, the share of FOB contracts is rising. For example, 45 medium- and long-term contracts were signed in 2022, of which 39 were signed by exporters from the US. Of the 39 contracts, only two were made on a DES basis. In contrast, only three of the remaining 16 contracts by other countries were made on an FOB basis (Figure 4.6).

Figure 0.6 Medium- and Long-term LNG Contracts Signed in 2022 by Destination Clause Type (Mtpa)



DES = delivered ex-ship, FOB = free on board, LNG = liquefied natural gas, Mtpa = million tonnes per annum.
Source: Energy Policy Research Foundation analysis from GIIGNL data.

4.4 Update of United States' LNG Export Policy under Trump 2.0 Administration

4.4.1 Lifting the Pause

At the time of writing, several policy priorities affecting LNG exports during the current administration have been spelled out by President Donald J. Trump's executive orders that he announced early in his second term. These executive orders served to roll back energy restrictions from the previous administration, as well as unlocking future energy resources by increased and faster permitting, leasing of federal lands, and providing the energy industry access to previously restricted areas. Three specific executive orders had the most effect on this trade issue.

Executive Order (E.O.) 14154, 'Unleashing American Energy,' lifted the 'pause' on issuing LNG export permits for trade with countries that do not have a free trade agreement with the United States. This executive order specifically mentions President Trump's 'energy dominance' phrase mentioned many times in both his campaigns and was considered a direct response to the industry's complaints about the effect on the LNG markets, as well as others. The executive order is broad and covers many topics related to energy including minerals, but section eight covers restarting reviews of applications for LNG export projects 'as expeditiously as possible' as well as setting strict limits for environmental reviews of deepwater ports designed for the export of LNG. E.O. 14154 also supports the approval of an application to construct an offshore, deepwater LNG project in the US Gulf,

which is pending with the Maritime Administration.

Section 2(d) of Executive Order 14153, 'Unleashing Alaska's Extraordinary Resource Potential,' prioritises the development of Alaska's LNG potential. Interestingly, this includes the sale of LNG to other parts of the United States, which would require LNG tankers built in the United States to comply with the Jones Act. At present, the US does not build LNG tankers, so compliance with the Jones Act regarding LNG is currently impossible. However, whilst buildout of LNG export capacity on the US west coast mainland is unlikely, E.O. 14153 would allow for a shorter route for US LNG exports to Asia if Alaska's LNG export capabilities were to be realised.

Finally, and probably most importantly, Executive Order 14156, 'Declaring a National Energy Emergency,' promotes the development of fossil fuels and infrastructure, including natural gas, for domestic use and allies. This extremely broad executive order covers a range of energy issues and identifies inadequacy of the US energy and critical minerals resources as a threat to national and economic security. The order contains six substantive sections, but the ones that pertain to the LNG export issue are section two, which covers emergency approvals, and section three, 'Expediting the Delivery of Energy Infrastructure.'

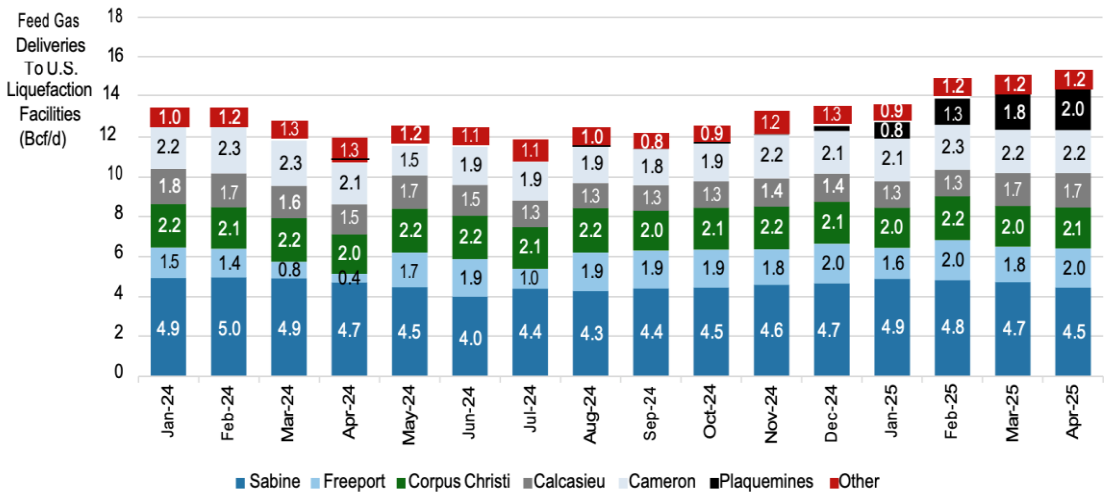
Section two states that 'The heads of executive departments and agencies…shall identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands.' The intent of this is to unlock the resources under federal government control and to allow for significantly increased energy production. Section three directs agencies to use all relevant lawful emergency and other authorities to: expedite the completion of authorised and appropriate energy projects; facilitate energy production and transportation through the west coast, northeast, and Alaska; and report on these activities to the Assistant to the President for Economic Policy. Clearly, if the goals of Executive Order 14156 are met, the increased resources could be leveraged with the other executive orders to allow for much greater LNG export. These changes have already begun to take effect at the US Department of Energy, inspiring confidence within the US LNG industry. In addition, on 11 June 2025, US Secretary of the Interior Doug Burgum and Secretary of Energy Chris Wright, chair and vice-chair of the National Energy Dominance Council respectively, announced with global CEO and chairman of JERA Co., Inc, Yukio Kani and US LNG producers the 'finalization of four 20-year agreements between JERA and US companies to purchase up to 5.5 million tons per year of American LNG.'

4.4.2 Short-term Trend after the Lift of the Pause

Feed gas deliveries to US liquefaction facilities averaged 0.42 bcm/d over the first 4 months of calendar year (CY) 2025, 0.05 bcm/d above year-ago levels (Figure 4.7). This aligns directionally with forecasts from the Energy Information Administration's (EIA) May

Short Term Energy Outlook calling for US LNG exports to rise from 90.44 Mtpa in CY 2024 to 110.96 Mtpa in CY 2025 (Figure 4.7).

Figure 0.7 Overall Feed Gas Deliveries to United States' Liquefaction Facilities Have Moved Higher in Recent Months (feed gas deliveries in billions of cubic feet per day)



Bcf/d = billions of cubic feet per day.
Source: Energy Policy Research Foundation analysis from Bloomberg data.

Table 0.2 EIA Projects a Substantial Increase in United States' LNG Exports in 2025 year-on-year

(billions of cubic feet per day; storage numbers are in billions of cubic feet)

CATEGORY	CY 2022	CY 2023	CY 2024	CY 2025P	CY 2026P
Dry Gas Production (Bcf/d)	99.3	103.6	103.2	104.9	106.4
LNG Imports (Bcf/d)	0.1	0	0	0	0.1
LNG Exports (Bcf/d)	10.6	11.9	11.9	14.6	16
Pipeline Gas Imports (Bcf/d)	8.2	8	8.5	8.9	8.9
Pipeline Gas Exports (Bcf/d)	8.3	8.9	9.1	9.9	10.5
Other (Bcf/d)	-1	0.1	-0.2	0.8	1.5
Total Supply (Bcf/d)	87.7	90.9	90.5	90.2	90.3
Total Demand (Bcf/d)	88.5	89.4	90.5	91.3	90.7
Working Gas Storage Change (Bcf)	-285	532	-18	-400	-151

Bcf/d = billions of cubic feet per day, CY = calendar year.
Source: Energy Policy Research Foundation analysis from Energy Information Administration data.

We should continue to see the concrete impact by the lift of the pause, but at the moment , it seems that some uncertainties related with the pause would be relatively eased. Of course, the uncertainties for future policy change by the United States and some other uncertainties related with tariff issues remain.

Table 0.3 United States' Liquefaction Projects Appearing to Approach Operation and Financial Investment Decisions

PROJECT	OWNER	ESTIMATED INITIAL IN-SERVICE DATE	CAPACITY (BCF/D)	FID DATE RECEIVED	EST. FID DECISION DATE
Plaquemines 1	Venture Global	CY 2024	1.3	May-22	
Freeport Debottlenecking	Freeoprt LNG	CY 2024	0.2	n/a	
CCL Stage 3	Cheniere	CY 2024	1.3	Jun-22	
Plaquemines 2	Venture Global	CY 2025	1.3	Mar-23	
Golden Pass Train 1	ExxonMobil / Qatar Petroleum	CY 2025	0.7	Feb-19	
Godlen Pass Train 2	ExxonMobil / Qatar Petroleum	CY 2026	0.7	Feb-19	
Golden Pass Train 3	ExxonMobil / Qatar Petroleum	CY 2027	0.7	Feb-19	
Rio Grande T1	Next Decade	CY 2027	0.7	Jul-23	
Port Arthur Phase 1 T1	Sempra	CY 2027	0.9	Mar-23	
Port Arthur Phase 1 T2	Sempra	CY 2028	0.9	Mar-23	
Rio Grande T2	Next Decade	CY 2028	0.7	Jul-23	
Rio Grande T3	Next Decade	CY 2029	0.7	Jul-23	
Louisiana LNG Phase 1	Woodside	CY 2029	2.2	Apr-25	
Commonwealth LNG	Kimmeridge	TBD	1.3	-	CY 2025
CP2 Phase 1	Venture Global	TBD	1.3	-	CY 2025
Texas LNG	Glenfame	TBD	0.5	-	CY 2025
Rio Grande T4	Next Decade	TBD	0.7	-	CY 2025
CCL Midscale T8-9	Cheniere	TBD	0.4	-	CY 2025
Lake Charles LNG	Energy Transfer	TBD	2.2	-	CY 2025
Port Arthur Phase 2	Sempra LNG	TBD	1.8	-	CY 2025
Delfin FNLG 1	Delfin Midstream	TBD	0.6	-	CY 2025
CP2 Phase 2	Venture Global	TBD	1.3	-	CY 2025
Sabine Pass Stage 5	Cheniere	TBD	1.8	-	Cy 2026/CY 2027
Plaquemines Expansion	Venture Global	TBD	2.4	-	CY 2027
Cameron Phase 2	Sempra	TBD	0.9	-	TBD
Freeport LNG T4	Freeport LNG	TBD	0.7	-	TBD
Louisiana LNG Phase 2	Woodside	TBD	1.4	-	TBD
Alaska LNG	Glenfame/AGDC	TBD	2.6	-	TBD
Delfin FLNG 2-3	Delfin Midstream	TBD	1.2	-	TBD

Rio Grande T5	Next Decade	TBD	0.7	-	TBD
Rio Grande T6	Next Decade	TBD	0.7	-	TBD
Rio Grande T7	Next Decade	TBD	0.7	-	TBD
Rio Grande T8	Next Decade	TBD	0.7	-	TBD
Gulfstream LNG	Gulfstream LNG	TBD	0.5	-	TBD
Magnolia LNG	Glenfame	TBD	1.2	-	TBD
FLNG	New Fortress Energy	TBD	0.4	Jan-21	
Qilak LNG	Qilak LNG	TBD	0.5	-	TBD
Delta LNG	Venture Global	TBD	3.2	-	TBD
CP3	Venture Global	TBD	3.9	-	TBD
Argent LNG	Argent LNG	TBD	3.2		TBD
Gulf Phase 1-2	Kinder Morgan	TBD	1.4	-	TBD
Crown FLNG	Crown LNG	TBD	1.2	-	TBD
PIC Americas	PIC Americas	TBD	0.9	-	TBD
Total	-	-	52.7	-	-

Bcf/d = billions of cubic feet per day, CY = calendar year, FID = final investment decision, TBD = to be determined.
Note: Company and media reports. The potential decision date is estimated.
Source: Energy Policy Research Foundation analysis.

4.4.3 Highlights from IEEJ, ERIA, EPRINC Events

1. Roundtable on 6 October 2024 at LNG PCC in Hiroshima

For LNG to play an important role as a transition energy source, particularly in Asia, where there are other options such as coal and renewable energy, a stable and sufficient supply at low cost is necessary.

In addition, in order for the LNG market to remain stable in the future with the goal of achieving net zero, it is important to ensure the continuity of investment and financing by presenting a scenario that clarifies the role of LNG as a transition energy source.

As for portfolio players, whilst there are expectations that they will fulfil the supply and demand adjustment function, concerns were raised about whether a fair relationship with buyers will be maintained as their influence grows.

Whilst the necessity of GHG emissions measures is shared, there are differences in opinions and enthusiasm regarding the method of cost burden. However, both parties shared the importance of continued exchange of opinions between sellers and buyers through a common platform, including such differences.

2. Workshop on 8 January 2025 in Washington, DC

As for the policy outlook for the Trump 2.0 administration, the view was shared that the pause will be lifted and US gas production and LNG exports will be expanded, but it was also confirmed that there remains uncertainty as to whether there will be an immediate effect due to concerns over the legal framework and litigation risks in the United States.

On the other hand, it was also shared that there is uncertainty about global LNG supply, and that the trend in US LNG exports will have a significant impact on the global energy market.

In addition, as a medium- to long-term outlook, it was shared that the world, especially Asia, will see an expansion in LNG demand. On the other hand, there is a wide range of demand outlooks amongst each institution, and financial institutions also expressed the view that renewable energy is more cost-competitive than gas-fired power in some countries.

In terms of finance, it was also revealed that there is a cautious attitude towards lending to gas and LNG projects due to the net-zero target.

3. Meeting on 11 March 2025 at Japan's reception in Houston

Regarding the US LNG policy and the synergy of Japan–US cooperation in the Asian market, the outlook for the US administration's LNG policy would be positive for the affordable LNG supply from the United States, which would be important in Asia's energy transition.

On the other hand, there could be some issues such as the continuity of US policy, verification of the business viability of individual LNG projects, and the relatively restrained stance on financing as seen in some international governmental statements.

4. Roundtable on 20 June 2025 at LNG PCC in Tokyo

Rising costs and prices of LNG projects are an issue for affordability and stabilisation of the LNG market. There is hope for cost containment efforts through technological development in production and sales, and for strengthened government support for imports and power generation infrastructure.

There is the importance of flexibility, the growing importance of gas-fired power due to an increase in variable renewable energy in Asia, and the need to consider it as an energy security package that includes coal.

The expansion of the Coalition for LNG Emission Abatement toward Net-zero as a spontaneous initiative by the companies is a positive sign for global methane reduction. In particular, from the perspective of production and sales, there are voluntary efficiency efforts as a cost reduction measure, which has been also contributing to reducing GHG emissions.

On the other hand, decarbonisation measures are generally costly, and how buyers and sellers should share the cost burden is a continuing issue. There is hope for stronger government support in these areas.

Regarding Russian natural gas and LNG, this is premised on the end of the war, but as Russia is one of the largest energy suppliers, normalising supplies is essential to stabilising the energy market.

Chapter 5.
Methane Emissions

5.1 Global Methane Emissions

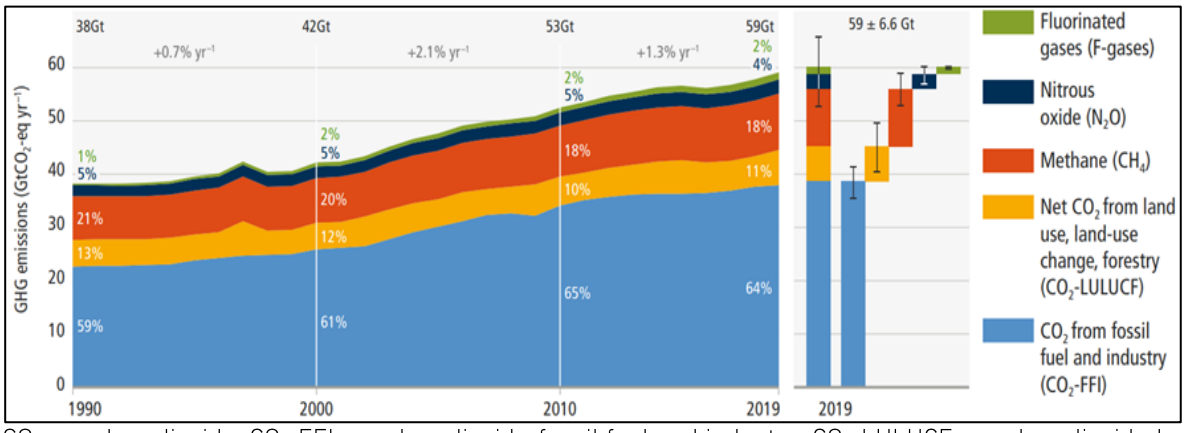
5.1.1 Methane Emissions Update

Section 5.1 provides an analysis of estimated data compiled by various research institutes worldwide and summarises the current state and challenges of methane emissions management globally, with a particular focus on the ASEAN region.

Intergovernmental Panel on Climate Change

The Intergovernmental Panel on Climate Change (IPCC) is a United Nations body dedicated to assessing the scientific evidence related to climate change (IPCC, 1988). Its primary objective is to provide policymakers with regular scientific assessments on the latest developments in climate change research. Established in 1988 by the World Meteorological Organization and the United Nations Environment Programme (UNEP) (IPCC, 1988), as of July 2024 the IPCC includes participation from 195 countries and regions. The IPCC evaluates the latest scientific findings on climate change and produces two types of reports: periodic assessment reports and thematic special reports. These comprehensive scientific assessments have been released every 5 to 7 years since the First Assessment Report in 1990. The Sixth Assessment Report synthesis was published in March 2023. Policymakers worldwide frequently cite IPCC reports, which serve as the basis for international negotiations, including the United Nations Framework Convention on Climate Change (UNFCCC), as well as for domestic policy development.

Figure 0.1 Global Net Anthropogenic Greenhouse Gas Emissions (1990–2019)



CO_2 = carbon dioxide; CO_2-FFI = carbon dioxide-fossil fuel and industry; CO_2-LULUCF = carbon dioxide-land use, land-use change, and forestry; GHG = greenhouse gas; Gt = gigatonnes.
Source: IPCC Sixth Assessment Report (Working Group III) (2022).

The IPCC Sixth Assessment Report (Working Group I), published in August 2021, assessed that 'there is no doubt that the increases in atmospheric CO_2, methane, and nitrous oxide (N_2O) since the pre-industrial era have been caused by human activities.' The report also states that the composition of global GHG emissions in 2019 consisted of 75% CO_2 (64% of which is from fossil fuels), 18% methane, 4% N_2O, and the remaining 2% fluorinated gases and others (Figure 5.1). Whilst most GHG emissions are derived from fuel and industry-related CO_2, methane has a global warming potential 28 times higher than that of $CO_2$and accounts for about 20% of total emissions.

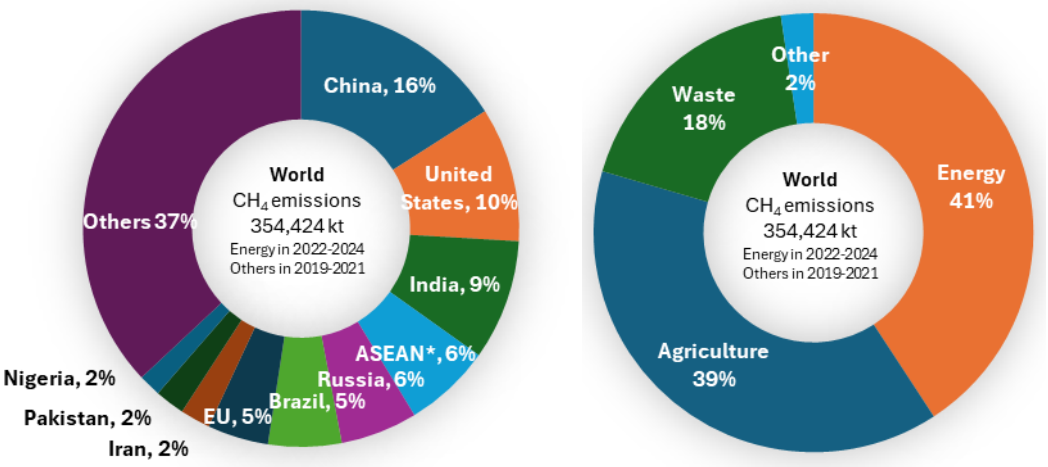
The IPCC is in its seventh assessment cycle, which formally began in July 2023 with the election of the new IPCC and taskforce bureaus at the IPCC's plenary session in Nairobi (IPCC, 2024).

Global Methane Tracker

The International Energy Agency (IEA) released the latest version of its Global Methane Tracker in May 2025, covering all sources of methane from human activities. For the energy sector, the tracker includes the IEA's estimates of methane emissions from the supply or use of fossil fuels (natural gas, oil, and coal) and bioenergy (such as solid bioenergy, liquid biofuels, and biogases) and, starting in 2025, abandoned facilities. The IEA claims that the tracker 'provides our latest estimates of emissions from across the sector – drawing on the most recent data and readings from satellites and ground-based measurements' (IEA, 2025).

For non-energy sectors such as waste, agriculture, and other sources, the tracker provides reference values based on publicly available data sources, providing a comprehensive picture of methane emissions. The IEA's approach to estimating methane emissions from global oil and gas operations relies on generating country-specific and production type-specific emissions intensities, which are then applied to production and consumption data on a country-by-country basis.

Figure 0.2 Global and ASEAN Methane Emissions (Share by Country) (2024)



ASEAN = Association of Southeast Asian Nations, CH_4 = methane, EU = European Union.
Note: The ASEAN countries included in the chart are Brunei Darussalam, Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam. Cambodia, Lao People's Democratic Republic, Myanmar, and Singapore are not included due to unavailability of data.
Source: Compiled from IEA (2025).

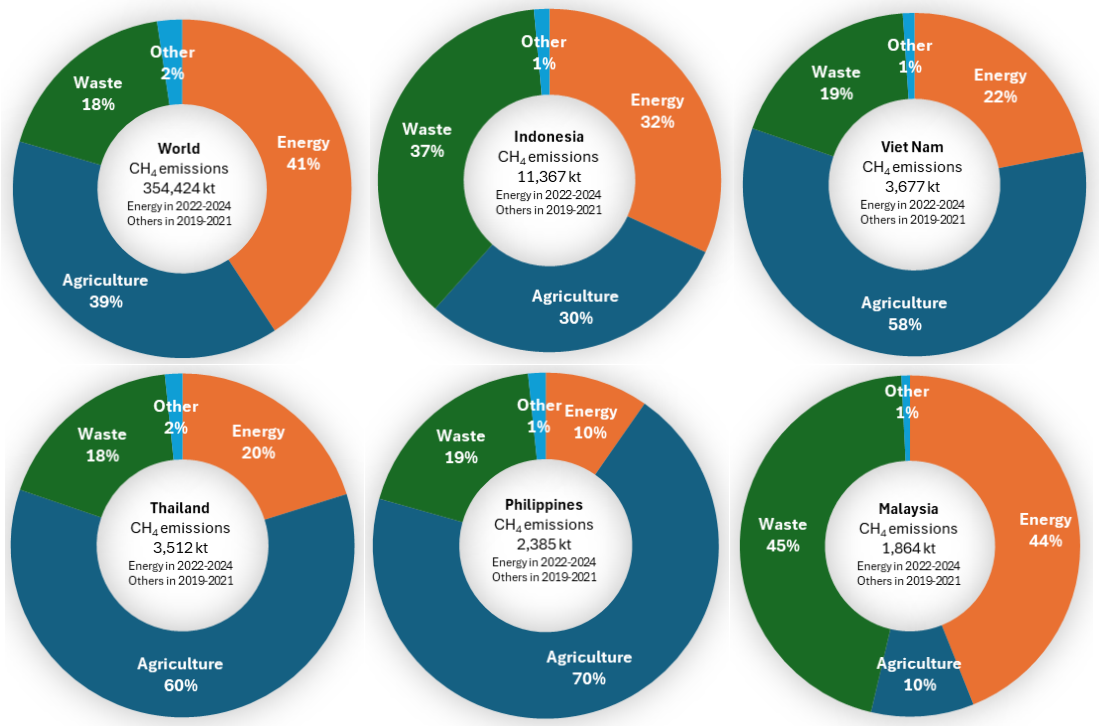
Figure 5.2 shows global methane emissions, estimated at 354.42 million tonnes in 2024, up 1.4% from 349.48 million tonnes the previous year. The largest emitter was China with 56.6 million tonnes (16% of the global total), followed by the US with 35.3 million tonnes (10%), India with 31.61 million tonnes (9%), and ASEAN with 22.87 million tonnes (6% of the global total). Within ASEAN, Indonesia accounted for the largest share with 11.37 million tonnes (50% of the ASEAN total), followed by Viet Nam with 3.68 million tonnes (16%) and Thailand with 3.51 million tonnes (15%).

Figure 5.3 summarises methane emissions by sector (agriculture, energy, waste, and others) for the world and selected ASEAN countries. Energy is the largest source of methane emissions worldwide, accounting for 41%, followed by agriculture at 39%, waste at 18%, and other sources at 2%. However, the areas of focus vary by country: in Indonesia, 30% of emissions come from agriculture; in Viet Nam, 58%; in Thailand, 60%; in the Philippines, 70%; and in Malaysia, 45% from waste.

According to the IEA, methane emissions from the energy sector totalled 144.6 million tonnes in 2024. Oil, coal, and natural gas account for 29%, 26%, and 21% of the energy industry's total emissions, respectively (Figure 5.4). In 2024, methane emissions from the natural gas sector reached 30.02 million tonnes, marking a 15.3% increase from the previous year's 26.03 million tons. This rise is attributed not only to increased natural gas production but also to improvements in measurement accuracy—such as the use of satellite technology—which have made it possible to detect emissions that previously went unnoticed. Globally, methane emissions from the natural gas sector occur primarily in the upstream segment, which accounts for 69% of total emissions. The midstream and downstream segments make up the remaining 31%. A similar trend is observed in ASEAN,

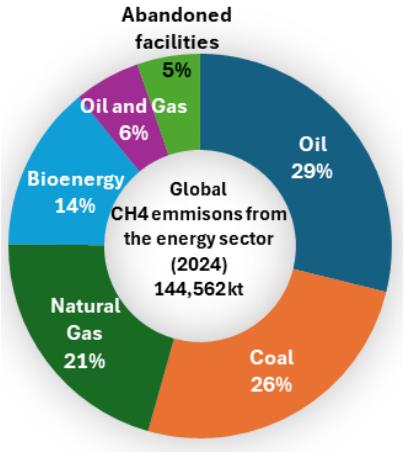
where the upstream segment accounts for 65% of methane emissions, whilst the midstream and downstream segments collectively account for 35% (Figure 5.5).

Figure 0.3 Methane Emissions by World and Selected ASEAN Countries (2024)



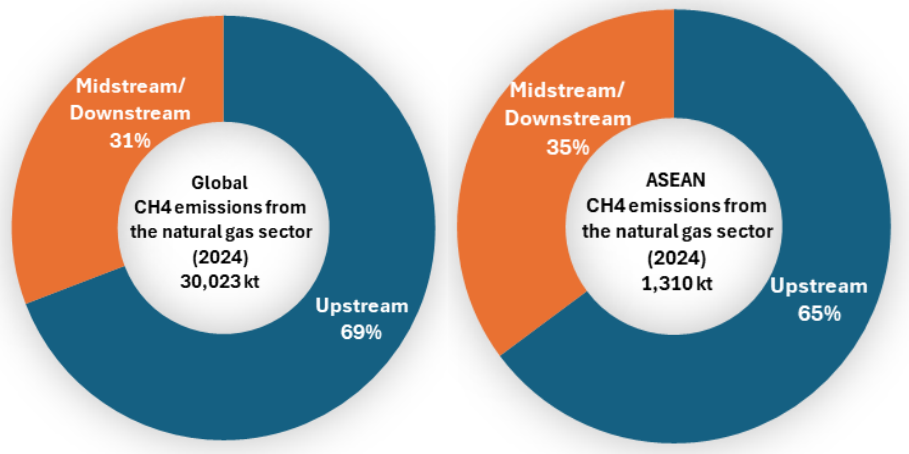
CH_4 = methane.
Note: Some data are not applicable.
Source: Compiled from IEA (2025).

Figure 0.4 Composition of Global Energy Sector Methane Emissions (2024)



CH_4 = methane.
Source: Compiled from IEA (2025).

Figure 0.5 Composition of Methane Emissions in the Natural Gas Sector (World, ASEAN) (2024)



ASEAN = Association of Southeast Asian Nations, CH_4 = methane, kt = kilotonne.
Source: Compiled from IEA (2025).

5.1.2 Natural Gas Production and Consumption in ASEAN Countries

Table 5.1 shows that Malaysia leads natural gas production in ASEAN, followed by Indonesia and Thailand, whilst Thailand is the largest consumer, followed by Indonesia and Malaysia. According to the IEA, methane emissions from the gas sector in ASEAN stand at 0.47 million tonnes in Malaysia, 0.42 million tonnes in Indonesia, and 0.34 million tonnes in Thailand.

Malaysia and Indonesia are recognised as key leaders in methane emissions management within ASEAN, demonstrating strong commitments to reducing emissions across the natural gas value chain.

In recent years, LNG imports have increased in Thailand, Singapore, and other ASEAN countries, with the Philippines and Viet Nam beginning LNG imports in 2023. As the region undergoes its energy transition, natural gas consumption in ASEAN is expected to increase, making it an even more important energy source.

Table 0.1 Natural Gas Production and Consumption by ASEAN Countries (2024)

(billion cubic metres)

	Production	LNG Export Volume	Pipeline Export Volume	Consumption	LNG Import Volume	Pipeline Import Volume
Brunei	10.4	6.4	-	-	-	-
Indonesia	71.4	16.5	3.9	47.3	-	-
Malaysia	80.4	36.0	-	46.2	4.2	0.4
Myanmar	14.8	-	10.0	-	-	-
Thailand	28.5	-	-	48.2	15.8	5.3
Viet Nam	6.1	-	-	6.1	-	-
Philippines	-	-	-	3.2	-	-
Singapore	-	-	-	13.0	8.4	6.0
Cambodia	-	-	-	-	-	-
Lao PDR	-	-	-	-	-	-

Lao PDR = Lao People's Democratic Republic, LNG = liquefied natural gas.
Source: Compiled from the 2025 The Energy Institute Statistical Review of World Energy (The Energy Institute, 2025).

5.1.3 Transparency and Accuracy of Methane Emissions

According to the IEA, whilst many countries and companies are working to improve the methods used to report methane emissions, in many parts of the world, emissions are still reported using approaches that rely little or not at all on direct measurement data. Measured emissions are generally found to be higher than the amounts officially reported. The IEA estimates that the total global energy-related methane emissions are approximately 80% higher than the total reported by countries to the UNFCCC.

The discrepancies between reported data and estimated emissions stem from various factors, which should be addressed through more systematic and transparent use of measured data. According to the Japan Organization for Metals and Energy Security's (JOGMEC) carbon intensity guidelines (JOGMEC, 2023), many GHG emissions calculations do not incorporate direct measurement but rely on secondary data, multiplying activity levels with standard emissions factors. Whilst using secondary data is more straightforward, it may not accurately reflect actual operating conditions, leading to potential misrepresentation of a project's emissions.

In 2023, an Oil and Gas Methane Partnership 2.0 (OGMP 2.0) member company in the United States compared methane emissions reported at Level 3 (general emissions factors) and Level 4 (asset-specific methods using measurements and simulations) (UNEP, 2023). The findings revealed that Level 4 emissions were 2.3 times higher than Level 3 estimates, with significant differences in source attribution.

There is a growing requirement for direct measurements of methane emissions to improve transparency and accuracy. Initiatives such as OGMP mandate reporting by source, incorporating some actual on-site measurements in emissions calculations.

5.1.4 Summary of Methane Emissions

The methane emissions reported by companies to the UNFCCC are significantly lower than the IEA's Global Methane Tracker estimates, suggesting that underestimation of emissions factors and unreported or unknown methane sources may be contributing factors. To address these issues, there is an urgent need for transparent data collection through direct measurements. Technological advancements, such as the use of satellites, have increased the quality of data, and the trend towards improving data accuracy is expected to continue.

Most methane emissions in the LNG value chain occur upstream. If natural gas is to remain a key clean energy source, it is essential to reduce methane emissions, particularly from upstream operations. According to Energy Institute statistics, ASEAN collectively ranks as the world's fourth-largest LNG exporter. It is also the fourth-largest methane emitter after China, the United States, and India, according to the IEA. Therefore, methane reductions in ASEAN could have a significant global impact.

The combined methane emissions of the top-three ASEAN countries in the natural gas sector— Malaysia, Indonesia, and Thailand—were around 1.23 million tonnes per year as of 2024, according to the IEA's Methane Tracker. A 30% reduction in these emissions, which the IEA notes is achievable at net-zero cost globally, could free up an additional 0.37 million tonnes of natural gas annually. This amount would be equivalent to 2%–3% of ASEAN's LNG imports as of 2024. Thus, reducing methane emissions could play an important role in strengthening ASEAN's energy security.

Malaysia and Indonesia, despite being amongst the largest producers and consumers of natural gas in ASEAN, have achieved notable success in methane management, including maintaining relatively low emissions levels. It is anticipated that other ASEAN countries will follow their lead in implementing methane emissions management initiatives.

As LNG imports continue to rise in Thailand, Singapore, and other countries, and as the Philippines and Viet Nam begin importing LNG, natural gas consumption is expected to increase during the energy transition. This makes methane emissions management a key priority for the region.

5.2 Policies for Methane Emissions Management

5.2.1 Policies and Regulations Outside ASEAN

Updates on methane emissions reduction policies in Australia, Canada, China, the European Union, Korea, and the United States are shown in the following sections.

Trends in the United States

The final rule aimed at reducing methane emissions and other pollutants from oil and gas operations was published in the Federal Register on 8 March 2024, whilst the Inflation Reduction Act introduced new powers under Section 136 of the Clean Air Act to address methane emissions in the petroleum and natural gas sectors through the creation of the

Methane Emissions Reduction Program, as both detailed in the previous years' reports. The moves in the Methane Emissions Reduction Program are summarised in Table 5.2.

Table 0.2 Moves in the Methane Emissions Reduction Program

	Biden Administration	Trump Administration	Source
Financial and Technical Assistance Clean Air Act (CAA) Section 136(a)-(b)	15 December 2023 – Formula Grants of a total of $350 Million for States to Support Methane Mitigation from Marginal Conventional Wells 20 December 2024 – Competitive Grants of $850 Million for Methane Emissions Monitoring and Mitigation		EPA, Financial Assistance from the Methane Emissions Reduction Program. Retrieved on 30 June 2025 https://www.epa.gov/inflation-reduction-act/financial-assistance-methane-emissions-reduction-program
Waste Emissions Charge (WEC) CAA Section 136(c)-(g)	18 November 2024 – Final Rule for Waste Emissions Charge for Petroleum and Natural Gas Systems (published in the Federal Register)	14 March 2025 – President Trump signs joint Congressional resolution disapproving final WEC rule 12 May 2025 – EPA issues final rule removing WEC regulation from Code of Federal Regulations	EPA, Waste Emissions Charge. Retrieved on 30 June 2025 https://www.epa.gov/inflation-reduction-act/waste-emissions-charge
Greenhouse Gas Reporting Program (GHGRP) Subpart W CAA Section 136(h)	14 May 2024 - Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas System (published in the Federal Register)	12 March 2025 – Reconsideration of the Greenhouse Gas Reporting Rule - Subpart W	EPA, Methane Emissions Reduction Program and GHGRP Subpart W (Petroleum and Natural Gas Systems). Retrieved on 30 June 2025 https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program-and-ghgrp-subpart-w-petroleum-and

Source: Compiled by authors.

Regarding financial assistance, on 20 December 2024, the Environmental Protection Agency and the Department of Energy announced approximately US$850 million for 43 projects that will help small oil and gas operators, Tribes, and other entities across the country to reduce, monitor, measure, and quantify methane emissions from the oil and gas sector.

Regarding the Waste Emissions Charge, on 18 November 2024, 'Final Rule for Waste Emissions Charge for Petroleum and Natural Gas Systems: Procedures for Facilitating Compliance, Including Netting and Exemptions' was published in the Federal Register. The Waste Emissions Charge final rule, however, was disapproved by a joint resolution of Congress pursuant to the Congressional Review Act. President Trump signed the Joint Resolution of Disapproval on 14 March 2025.

Regarding the Greenhouse Gas Reporting Program (GHGRP) Subpart W (Petroleum and Natural Gas Systems), on 14 May 2024, 'Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems' was published in the Federal Register. On 12 May 2025, the EPA announced the agency is reconsidering the mandatory GHGRP, including 'Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems.'

Trends in the European Union

On 15 July 2024, the 'Regulation (EU) 2024/1787 of the European Parliament and of the Council of 13 June 2024 on the reduction of methane emissions in the energy sector and amending Regulation (EU) 2019/942' was published in the Official Journal (European Union, 2024).

On 16 June 2025, at the Energy Council of the European Union, the Bulgarian, the Czech, Greek, Hungarian, Romanian, Slovakian, and Slovenian delegations informed ministers about the challenge in implementing the Methane Regulation (Council of European Union, 2025a). In the Presidency conclusions on strengthening the Energy Union through reinforcing energy security, the Presidency of the Council of the European Union reiterated that 'the existing energy acquis may be in need of simplification, including under the Omnibus programme, [...], for example in the context of the Methane regulation, [...].' (Council of European Union, 2025b).

It is still to be confirmed if an Energy Omnibus will be published.

Trends in Canada

In December 2023, Environment and Climate Change Canada published a Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap, whilst Regulations Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) were published in the Canada

Gazette for consultation on 16 December 2023.

On 4 November 2024, Canada announced the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations (Government of Canada, 2024). Key components of the proposed national cap-and-trade system for oil and gas greenhouse gas pollution are shown in Table 5.3.

Table 0.3 Key Components of the Proposed National Cap-and-trade System for Oil and Gas Greenhouse Gas Pollution

Coverage / Applicability	● A national cap-and-trade system would apply to upstream oil and gas activities including onshore and offshore oil and gas production; oils and production and upgrading; natural gas production and processing; and the production of LNG. ● Large operators (producing above an annual threshold of 365,000 barrels of oil equivalent) would have to remit allowances to cover their emissions.
Allocation and remittance	● The cap-and-trade system will freely allocate emissions allowances to facilities covered by the system. ● The proposed regulations would use data reported by operators for 2026 to set the first oil and gas GHG pollution cap level. The oil and gas GHG pollution cap for the first compliance period, 2030-2032, would be set at 27% below emissions reported for 2026, which is estimated to be equivalent to 35% below 2019 emissions. The final oil and gas GHG pollution cap level would be published before the end of 2027. ● The proposed regulations allocate allowances to covered operators using specified distribution rates –defined in allowances per unit of production – for each type of covered activity. Allowances will be distributed before the start of each year (starting in 2029 for 2030, the first compliance year). Allowances would be pro-rated across all covered operators' facilities based on historical production volumes. ● At the end of each year, each facility will need to remit to the government one allowance for each tonne of carbon pollution it has emitted.
Contribution to a decarbonisation programme and the use of offsets	● Operators can contribute to a decarbonisation programme or use GHG offset credits to cover a small portion of their emissions (up to 10% for the decarbonisation programme and up to 20% for offsets, for a maximum of 20% for both options). ● The decarbonisation programme would fund projects that support the reduction of emissions from the sector
Banking	● Emissions allowances and offsets could be banked for use in a limited number of future years. D ecarbonisation units would not be tradable or bankable.

Schedule	● The system would be phased in for the first 4 years (2026–2029).
	● During that period, operators would be required to register and report their emissions and production.
	  ● Large emitters will start reporting in 2027 for their 2026 emissions and production levels.
	  ● Reporting for small operators would start in 2029 for their 2028 levels.

	• Operators would need to submit verified annual reports to Environment and Climate Change Canada for their facilities for every calendar year. • Reports would be due on 1 June of the following year.

Source: Environment and Climate Change Canada (2024).

Trends in Australia

2023–2024 was the first compliance period of the reformed Safeguard Mechanism. Table 5.4 shows the key elements of the Safeguard Mechanism.

Table 0.4 Key Elements of the Safeguard Mechanism

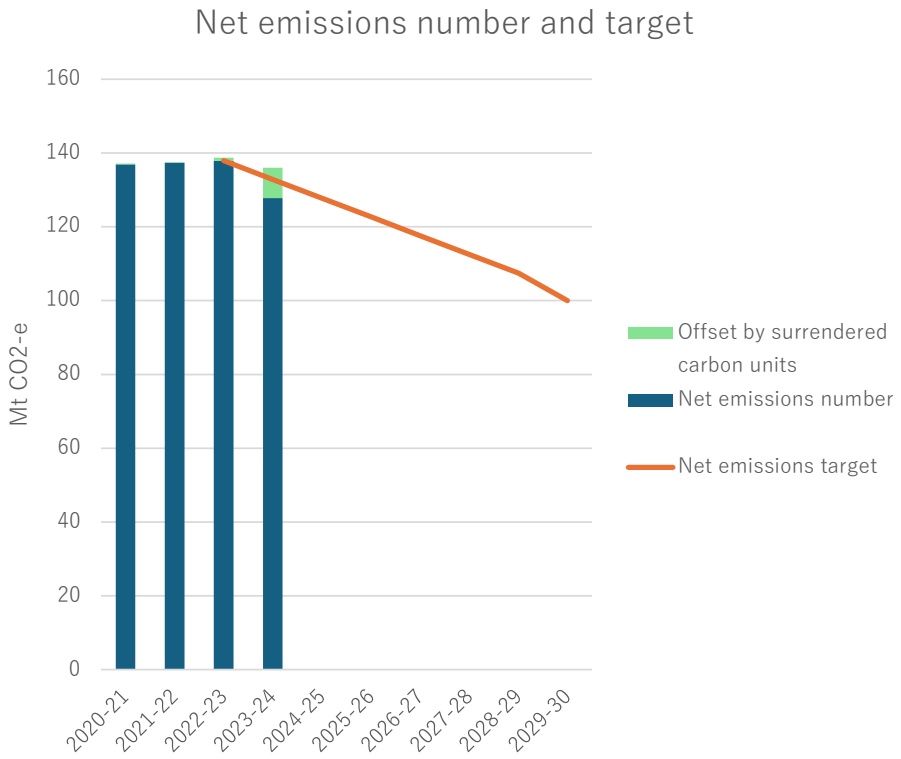
Starting year	The reformed Safeguard Mechanism started in 2023–24 (1 July 2023).
Applicability / Coverage	The Safeguard Mechanism applies to facilities across a range of sectors – including coal mining, metal ore mining, oil and gas extraction, manufacturing, and transport – that emit more than 100,000 CO_2-e in a year. In 2023–24 covered emissions from safeguard facilities made up of 31% of Australia's total emissions in that year. 219 facilities were covered by the Safeguard Mechanism.
Net emissions target	Net emissions from all safeguard facilities should not exceed 1,233 Mt CO_2e in total over the decade from 1 July 2020 to 30 June 2030 and 100 Mt CO_2e in 2029-30.
Baselines	The Safeguard Mechanism sets baselines on the greenhouse gas emissions of covered facilities. Under the reformed mechanism these baselines generally decline by 4.9% each year.
Surrender of Safeguard Mechanism Credits (SMCs) and Australian Carbon Credit Units (ACCUs)	If facilities are under their baseline, they may be eligible to generate SMCs. If facilities are over their baseline they are required to manage these excess emissions. Facilities have options, including surrendering ACCUs and SMCs.

Source: Clean Energy Regulator (2025).

The 2023–2024 safeguard data show (Clean Energy Regulator, 2025):

- Covered emissions reduced from 138.7 million tonnes of carbon dioxide equivalent (Mt CO_2e) in 2022–2023, to 136.0 Mt CO_2e in 2023–2024.
- Facilities surrendered 1.4 million Safeguard Mechanism Credits (SMCs) and 7.1 million Australian Carbon Credit Units (ACCUs).
- Following the surrender of ACCUs and SMCs, net safeguard emissions fell from 137.9 Mt CO_2e to 127.8 Mt CO_2e as shown in Figure 5.6.

Figure 0.6 2023–2024 Safeguard Data: Net Emissions Number and Target



Mt CO_2e = million tonnes of carbon dioxide equivalent.
Source: Clean Energy Regulator (2025).

Trends in China

Recent moves in China's methane emissions reduction policies are summarised in Table 5.5.

Table 0.5 Moves in China's Methane Emissions Reduction Policies

Launch of China's first high-resolution methane monitoring satellite	On 11 November 2024, China launched the Lijian-1 Y5 commercial carrier rocket with 15 satellites on board, including the Xiguang-1 04 satellite, which is China's first high-resolution methane monitoring commercial satellite. According to the satellite developer, Xiopm SPACE, a commercial space company set up by Xi'an Institute of Optics and Precision mechanics under the Chinese Academy of Sciences. It is equipped with a methane camera, a chlorophyll camera, and a multi-spectral camera. The satellite has multiple functions such as methane emission monitoring and trend tracking, and carbon source identification. The satellite will achieve high-frequency, high-precision observations of methane leaks from point sources globally.
Emission standard of coalbed methane (coal mine gas)	On 1 December 2024, the Ministry of Ecology and Environment and the State Administration for Market Regulation issued the Emission Standard of Coalbed Methane (coal mine gas) (GB 21522-2024), which stipulates the requirements on drainage, emissions control, monitoring, implementation,

	and supervision of coalbed methane (coal mine gas). This standard revised GB 21522-2008.

Sources: Xinhua (2024) and Ministry of Ecology and Environment and State Administration for Market Regulation (2024).

Trends in the Republic of Korea

Korea announced the 2030 Methane Reduction Roadmap in November 2023, but a detailed plan is not formulated.

The ASEAN–Korea Cooperation on Methane Mitigation (AKCMM) is a 3-year (2024–2027), USD$20 million project with a goal of catalysing the reduction of methane emissions in the ASEAN region (ASEAN–Korea Cooperation Fund, 2024). The AKCMM is the first project under the Partnership for ASEAN–Republic of Korea Methane Action (PARMA) – an umbrella initiative launched at the 23rd ASEAN–Republic of Korea summit in Cambodia – that encourages matchmaking of ASEAN's needs and Korea's solution to address barriers to methane reduction. As the first project under PARMA, the AKCMM offers a broad range of technical assistance to participating ASEAN Member States. The AKCMM supports activities that:

1. Strengthen institutions, policies, and regulations associated with methane emissions reduction;
2. Improve the accuracy and reliability of methane emissions measurements;
3. Utilise blended finance and innovative approaches, in collaboration with the private sector, to achieve measurable verifiable methane emissions reductions, and;
4. Promotes regional knowledge sharing of best practices and lessons learned.

5.3 Corporate Initiatives on Methane Emissions Management

Section 5.3 summarises the main initiatives and frameworks adopted by companies worldwide to manage their methane emissions, along with emissions reduction targets. It also describes each company's approach to methane emissions management.

5.3.1 Improving Transparency

Setting Emissions Reduction Targets and Disclosure of Methane Emissions

Table 5.6 shows the methane emissions reduction targets of selected companies worldwide. The specific targets vary by company, although they are all publicly disclosed. European companies often have goals focused on reducing both methane emissions and methane emissions intensity, whilst many Asian companies primarily target overall GHG emissions reduction, as shown in a survey of ASEAN companies.

In recent years, however, an increasing number of Asian companies – including INPEX, PETRONAS, PTT, and PERTAMINA – have begun setting specific methane reduction targets, reflecting growing awareness and alignment with global best practices.

Table 0.6 Methane Emissions Reduction Targets of Selected Companies Worldwide

Company	Methane Emissions Reduction Target
BP	Methane emissions intensity below 0.2% by 2025
Shell	Maintain methane emissions intensity of Shell-operated oil and gas assets (including LNG) to below 0.2% and achieve near-zero methane emissions by 2030
TotalEnergies	1. Reduce methane emissions by 60% from 2020 levels by 2025 2. Reduce methane emissions by 80% from 2020 levels by 2030
Enagás	Reduce methane emissions on volume basis by 45% by 2025 and 60% by 2030 compared to 2015
INPEX	Maintain methane emissions intensity at about 0.1%
JAPEX	GHG emissions reduction targets
Tokyo Gas	GHG emissions reduction targets
PETRONAS	1) Reduce methane emissions on volume basis from the entire PETRONAS Group natural gas value chain by 50% by 2025 from 2019 levels 2) Reduce methane emissions on volume basis from the entire PETRONAS Group natural gas value chain by 70% by 2030 from 2019 levels
Pavilion Energy	GHG emissions reduction targets
PTT	Reduce methane emissions intensity to less than 0.2% by 2030
PERTAMINA	40% reduction in methane emissions from the 2021 baseline

GHG = greenhouse gas, INPEX = International Petroleum Exploration, JAPEX = Japan Petroleum Exploration, LNG = liquefied natural gas, PETRONAS = Petroliam Nasional Berhad, PTT = PTT Public Company.

Sources: Company data.

Table 5.7 shows data on the methane emissions and intensities of selected companies worldwide. In recent years, many companies have begun disclosing this information due to the growing importance of methane emissions management worldwide. Some companies have refined their reporting processes, breaking down emissions by factor, GHG type, and domestic versus overseas emissions. However, there is still variation in

how methane emissions are calculated, indicating a need for standardisation and improved transparency in the future.

Table 0.7 Methane Emissions of Selected Global Companies

Company	Methane Emissions (tonnes)	Methane Intensity (%)
BP	46,000 (2024)	0.07 (2024)
Shell	33,000 (2024)	0.04 (2024)
TotalEnergies	29,000 (2024)	0.10 (2024)
Enagás	1,850 (2024)	-
INPEX	-	0.05 (2024)
JAPEX	2,101 (FY2023)	-
Tokyo Gas	286 (FY2023)	-
PETRONAS	169,450 (2024)	0.32 (2024)
Pavilion Energy	Only GHG emissions are published	-
PTT	45,956 (2024)	-
PERTAMINA	90,000 (2024)	-

BP = British Petroleum, INPEX = International Petroleum Exploration, JAPEX = Japan Petroleum Exploration, PETRONAS = Petroliam Nasional Berhad, PTT = PTT Public Company.
Source: Compiled from company data.

Certification

(i) ExxonMobil, BP, Kimmeridge (MiQ)

In September 2021, ExxonMobil announced that its Poker Lake facilities in the Permian Basin, New Mexico, had received the highest-grade 'A' certification from MiQ for methane emissions control in natural gas production (ExxonMobil, 2021). By April 2022, the Permian Basin facilities' production of 200 million cubic feet per day of natural gas had also been awarded MiQ's highest 'A' grade, making ExxonMobil the first company to receive certification for petroleum-associated natural gas production (ExxonMobil, 2022).

In March 2023, BP's US onshore natural gas producer, bpx Energy, announced it had obtained MiQ certification for all its onshore operations in Texas and Louisiana in the US (BP, 2023).

In November 2024, Kimmeridge announced that both Commonwealth LNG and Kimmeridge Texas Gas (KTG) would obtain independent certification based on MiQ standards. Commonwealth plans to begin certification within one month after the start of commercial operations, whilst KTG aims to complete certification by the end of 2025.

(ii) Cheniere Energy

In August 2021, Cheniere Energy, based in the US, announced an LNG life-cycle analysis aimed at improving its assessment of GHG emissions. This analysis utilises data specific to Cheniere's LNG supply chain and serves as the basic analysis tool for the company's cargo emissions tags (CE Tags), which provide GHG emissions estimates for each cargo. In April 2022, Cheniere announced its collaboration with midstream natural gas companies, methane detection technology providers, and research institutions such as Colorado State University. This partnership is focused on quantifying, monitoring, reporting, and verifying GHG emissions throughout its LNG supply chain, using surface-based, mid-air, and drone emissions tracking and monitoring technologies. In October 2022, Cheniere joined the OGMP 2.0 initiative and began issuing CE Tags to buyers, detailing the estimated GHG emissions for each cargo produced. In November 2024, the company released an updated version of its LNG life-cycle assessment, featuring a new 'Gas Path Algorithm' that enables more accurate modelling of emissions across the entire LNG supply chain (Cheniere Energy, 2024).

(iii) QatarEnergy, Pavilion Energy, Chevron

In April 2020, Singapore's Pavilion Energy issued a request for LNG deliveries of up to 2 million tonnes per year over a 5-year period beginning in 2023. This request included a requirement for suppliers to collaborate in establishing and implementing GHG measurement and reporting methods, covering emissions from the wellhead to the unloading terminal. Subsequently, in November 2020, Qatar Petroleum (now QatarEnergy) signed a deal with Pavilion Energy, marking the first long-term LNG deal to include environmental conditions aimed at reducing the carbon footprint of the LNG supply. In November 2021, Pavilion Energy, QatarEnergy, and Chevron announced the development of a quantification and reporting methodology to produce a Statement of GHG Emissions for LNG cargoes. The statement of GHG emissions methodology complements GIIGNL's measurement, monitoring, reporting, and verification (MRV) and GHG neutral framework efforts (Pavilion Energy, 2020; Chevron, 2021).

5.3.2 Initiatives on Methane Emission Management

Measurement, monitoring, and leak detection and repair

(i) TotalEnergies

In May 2022, TotalEnergies launched a worldwide campaign to detect and quantify methane emissions across all its upstream oil and gas operations, reinforcing its commitment to reducing emissions. The campaign uses Airborne Ultralight Spectrometer for Environmental Applications (AUSEA) technology, developed in collaboration with the French National Research Centre for Scientific Research and the University of Reims Champagne Ardenne.

AUSEA is a small dual sensor mounted on a drone, capable of detecting methane and CO_2 emissions and identifying their source. This cutting-edge technology allows for accurate

measurements at all types of industrial facilities, onshore and offshore. AUSEA complements conventional detection methods such as infrared cameras, ground-based sensors, and satellite monitoring (TotalEnergies, 2022a).

(ii) Chevron

In 2023, Chevron contracted GHGSat to monitor methane emissions at 18 oil and gas production facilities worldwide using GHGSat's high-resolution satellite technology. This advanced system can detect and quantify methane emissions from onshore industrial sources. Chevron and GHGSat will continue collaborating on further onshore methane monitoring projects, as well as pilot projects for offshore methane monitoring (GHGSat, 2022).

(iii)QatarEnergy

QatarEnergy has implemented leak detection and repair (LDAR) programmes across its operations. Under this programme, the company measures 100% of the relevant components in its operated assets using toxic vapour analysers (TVAs), following Method 21 from the US Environmental Protection Agency (EPA). The company is also adopting a SMART LDAR approach, where 50% of components are monitored using optical gas imaging cameras, whilst the remaining 50% are measured using TVAs. All components and measurements are recorded in an LDAR software system, allowing calculation and reporting of fugitive emissions (Qatarenergy, 2022).

Flare and venting reduction

(i) PETRONAS

In November 2021, PETRONAS announced its support to the World Bank's Zero Routine Flaring by 2030 Initiative. Under this initiative, PETRONAS pledges to eliminate steady-state flaring in existing oil production sites by 2030, and avoid it altogether in new oil field development. As a result of our methane reduction efforts, PETRONAS achieved a 62% reduction in methane emissions across its groupwide natural gas value chain in 2024 compared to 2019 levels, surpassing the 2025 target of a 50% reduction. This progress was driven by the effective implementation of flaring and venting reduction projects across both upstream and gas businesses (PETRONAS, 2021, 2025).

(ii) JAPEX

Japan Petroleum Exploration Co., Ltd. (JAPEX) mitigates vent emissions during normal operations by flaring as much excess gas as possible. Low-pressure excess gas, associated with crude oil production, is not flared but instead used as in-house fuel. The company compiles and analyses monthly flare emissions by site, providing feedback to each location to determine abnormalities in flare volumes and further explore reduction measures.

5.3.3 Cooperation with Others

Membership in initiatives and frameworks

Table 5.8 shows major initiatives and frameworks that selected companies worldwide are affiliated with. European companies are typically members of more initiatives and frameworks than their Asian counterparts. Each company participates in at least one initiative or framework, where it measures, reports, and certifies its activities.

Table 0.8 Selected Companies Worldwide and Affiliations with Major Initiatives and Frameworks

Company	Initiative and Framework
BP	OGCI, OGMP 2.0, etc.
Shell	OGCI, OGMP 2.0, etc.
TotalEnergies	OGCI, OGMP 2.0, etc.
Enagás	OGMP 2.0, GIIGNL, etc.
INPEX	OGMP 2.0, GIIGNL (Associate Members), etc.
JAPEX	GIIGNL (Associate Members), etc.
Tokyo Gas	GIIGNL, etc.
PETRONAS	OGMP 2.0, etc.
PTT	OGMP 2.0, GIIGNL, etc.
PERTAMINA	OGMP 2.0, GIIGNL (associate members), etc.

BP = British Petroleum, GIIGNL = International Group of Liquefied Natural Gas Importers, INPEX = International Petroleum Exploration, JAPEX = Japan Petroleum Exploration, OGCI = Oil and Gas Climate Initiative, OGMP 2.0 = Oil and Gas Methane Partnership 2.0, PETRONAS = Petroliam Nasional Berhad, PTT = PTT Public Company.
Source: Compiled from company data.

Sharing of expertise

(i) TotalEnergies

TotalEnergies (2024) has been sharing its AUSEA drone detection and measurement technology for methane emissions with several national oil companies, including Petrobras (Brazil), Sonangol (Angola), the Nigerian National Petroleum Company, the State Oil Company of the Republic of Azerbaijan, and the Oil and Natural Gas Corporation (India). This collaboration aims to enhance the detection, measurement, and reduction of methane emissions across these companies' operations.

(ii) JOGMEC–PETRONAS and PERTAMINA

In March 2023, PETRONAS signed a memorandum of collaboration with the Japan Organization for Metals and Energy Security (JOGMEC) to unlock the potential of cleaner energy production and methane abatement opportunities. This collaboration supports decarbonisation goals in both Japan and Malaysia, focusing on the development of technology for methane measurements and the reduction of routine flaring (PETRONAS, 2023).

In December 2023, PERTAMINA and JOGMEC also formalised a cooperation agreement to measure and quantify methane emissions at natural gas production facilities in Indonesia. This partnership focuses on methane emissions management projects and carbon intensity calculations for upstream natural gas operations (PERTAMINA, 2023).

(iii) Methane Leadership Program

In June 2023, PETRONAS launched the ASEAN Energy Sector Methane Leadership Program in collaboration with ASEAN energy companies, government agencies, and international organisations. A flagship methane reduction project was announced in partnership with JOGMEC, focusing on methane quantification studies, feasible solutions for achieving zero daily flaring, and potential future cooperation on electrification hubs (PETRONAS, 2023).

The programme's first master class, held in November 2023, drew 65 participants representing Methane Leadership Program partners and ASEAN oil and gas companies from Malaysia, Indonesia, Thailand, and Viet Nam (ASEAN Centre for Energy, 2024). In October 2024, the Methane Leadership Programme 2.0 (MLP 2.0) was launched under the theme 'Turning Capacity into Action' (Figure 5.7) The new phase aims to strengthen collaboration between industry and government whilst advancing a region-wide effort to reduce methane emissions.

Figure 0.7 Launch of the Energy Sector Methane Leadership Program

Source: PETRONAS.

(iv) Coalition for LNG Emission Abatement toward Net-zero

On 18 July 2023, JERA, the largest domestic power producer in Japan, and KOGAS, the largest domestic natural gas supplier in the Republic of Korea, launched the Coalition for LNG Emission Abatement toward Net-zero (CLEAN) (Ministry of Economy, Trade and Industry, 2023) to reduce methane emissions. The announcement was made at the LNG Producer–Consumer Conference held the same day. At the conference, the governments of Australia, the European Commission, Japan, the Republic of Korea, and the US signed a joint statement emphasising the importance of CLEAN in reducing GHG, particularly methane, throughout the LNG value chain.

CLEAN represents a collaboration between LNG consumers and producers to reduce methane emissions along the entire LNG value chain. With the support of the governments of Japan, the Republic of Korea, the US, and JOGMEC, the initiative aims to improve transparency by engaging in dialogue with LNG producers and promoting best practices to reduce methane emissions. JOGMEC will support CLEAN by providing a platform to share information on methane reduction targets and measures.

This initiative is significant as it marks the first time two of the world's largest LNG importers have jointly requested greater transparency in the GHG profiles of the LNG they import. Its success hinges on broad industry participation and the effective implementation of the initiative. CLEAN is also expected to contribute to the standardisation of MRVs in gas and LNG production.

At the LNG Producer–Consumer Conference 2024, JOGMEC announced the publication of the CLEAN Annual Report 2024, marking the first outcomes of the CLEAN initiative (JOGMEC, 2024). This report presents the results of a methane emissions reduction survey sent by JERA and KOGAS to LNG producers with whom they have signed sale and purchase agreements. It publicly discloses, for the first time on a project-by-project basis,

information on methane emissions and reduction efforts, highlighting the best practices across the industry.

At the LNG Producer–Consumer Conference 2025, a new partnership was announced between UNEP–IMEO and the CLEAN initiative to jointly pursue efforts to provide more transparent and harmonised project-level data on methane emissions from the LNG value chain (Figure 5.8). The CLEAN framework continues to expand: by October 2024, 22 companies had newly joined the initiative. By the time of the 2025 Conference, three additional companies had joined, bringing the total number of participating companies to 27. The importance of the CLEAN initiative has also been increasingly recognised by LNG producers and international organisations, with entities such as the Abu Dhabi National Oil Company and MiQ a certification body for greenhouse gas emissions across the natural gas value chain joining the initiative. To date, 19 international organisations, associations, and companies have expressed their support for CLEAN (JOGMEC, 2025).

Figure 0.8 Liquefied Natural Gas Producer–Consumer Conference

Source: Ministry of Economy, Trade and Industry (2025).

5.3.4 Technology Development and Operational Improvement

Measurement innovations

(i) International Methane Emissions Observatory

At the 2022 UN Climate Change Conference in Sharm El-Sheikh, Egypt (COP27), UNEP's International Methane Emissions Observatory (IMEO) launched the Methane Alert and Response System (MARS). MARS is the first global system to connect satellite-detected

methane emissions with a transparent notification process, encouraging swift mitigation efforts on the ground (IMEO, 2023). IMEO's third annual report 'An Eye on Methane', released on 1 December 2023, revealed the first public data from MARS. In its inaugural pilot year, focused primarily on the energy sector, IMEO identified around 1,500 methane plumes and sent over 120 MARS notifications across four continents. For instance, a leak at an oil and gas facility was flagged, prompting the company to address the issue and establish a long-term prevention plan.

(ii) Environmental Defense Fund and Google

In March 2024, the Environmental Defense Fund (EDF) and Google launched MethaneSAT, a cutting-edge satellite designed to measure and analyse methane emissions from major oil and gas-producing regions (Figure 5.9). MethaneSAT is equipped with highly sensitive spectrometers capable of detecting not only large emissions sources (super emitters) across wide areas, but also smaller sources that had previously been undetectable from space. The mission aimed to generate high-quality, actionable methane emissions data and make it freely available to researchers, regulators, and the public. Over the course of its first year in orbit, MethaneSAT delivered unprecedented insights into the distribution and volume of methane emissions, setting a new standard for satellite-based emissions monitoring. With its advanced algorithms and data processing software, the satellite enabled the conversion of observational data into quantitative emissions estimates, significantly enhancing global methane tracking capabilities.

However, on 20 June 2025, the mission team lost contact with MethaneSAT (Environmental Defense Fund, 2025). Despite all efforts to restore communication, it was confirmed on 1 July 2025, that the satellite had lost power and was likely unrecoverable. Whilst this early loss is disappointing, the EDF has emphasised that its core mission – to turn data into action – will continue. The engineering team has been investigating the cause of the communication failure, and the data already retrieved from the satellite will continue being processed and released over the coming months. Furthermore, the technologies and methodologies established through the MethaneSAT mission will be leveraged by EDF and partners around the world moving forward.

(iii) JGC Holdings Corporation

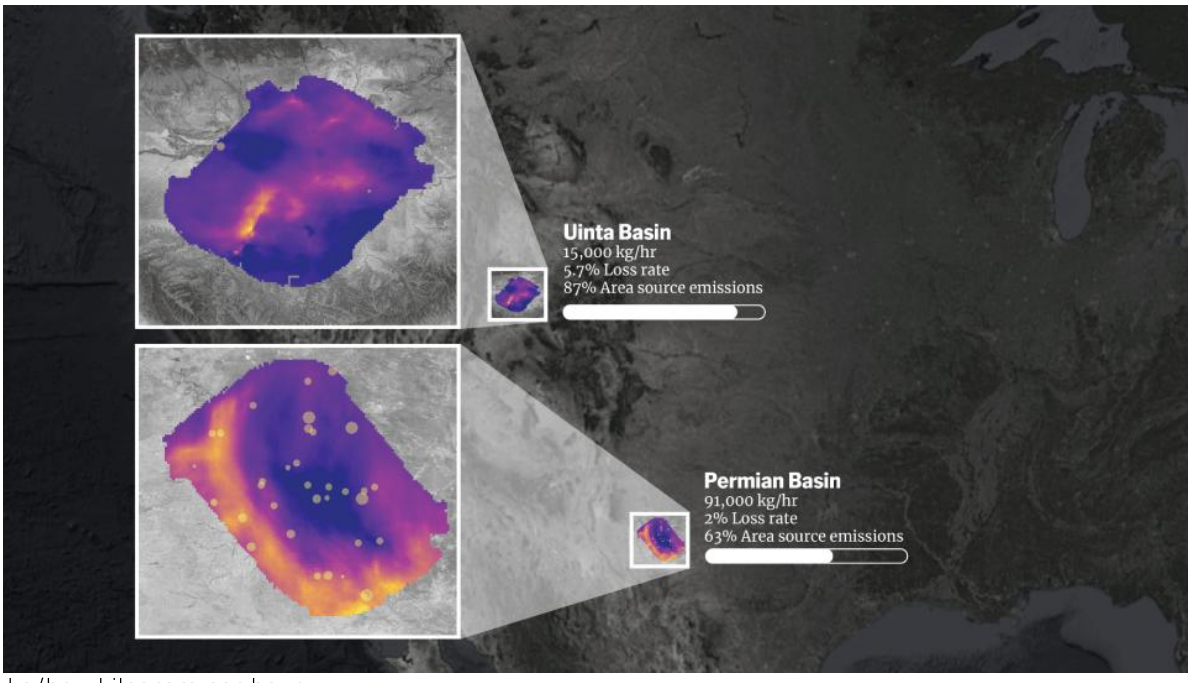
In March 2023, JGC Holdings Corporation (2023a) announced the construction of a facility at its research and development centre in Oarai, Ibaraki in Japan, for evaluating methane emissions measurement techniques (Figure 5.10). The facility aims to support domestic and overseas manufacturers by providing a platform to evaluate their detection capabilities and develop advance methane emissions measurement technologies, which are still in their early stages worldwide. With JOGMEC's support, five domestic and foreign companies, including Konica Minolta and All Nippon Airways (ANA), SeekOps (US), The Sniffers (Europe), and Aeromon (Europe) conducted tests at the facility in February 2023 to evaluate their methane measurement technology.

(iv) Japan Organization for Metals and Energy Security

In November 2022, JOGMEC announced a partnership with ANA to conduct a study on GHG measurement using aircraft and drones. The Japan Aerospace Exploration Agency, which has been working with ANA on verifying the technology, is also involved in this project. The three organisations aim to implement a top-down measurement method, expected to become a verification standard for reported GHG emissions (JOGMEC, 2022).

In October 2024, JOGMEC and PETRONAS announced the establishment of the Southeast Asia Methane Emissions Technology Evaluation Centre, the first methane emissions management test facility in the ASEAN region, during the ASEAN MLP 2.0 meeting (PETRONAS, 2024). This centre will focus on developing emissions management approaches tailored to the region's specific climate conditions and offshore natural gas infrastructure. In collaboration with PETRONAS, Universiti Teknologi PETRONAS, and Institut Teknologi Petroleum PETRONAS, the facility will support the development of practical solutions by evaluating methods for the MRV of methane emissions. By providing an environment for pre-implementation technology assessment, the initiative aims to help companies plan and implement effective emissions reduction strategies efficiently.

Figure 0.9 Methane SAT



kg/hr = kilogram per hour.
Note: Basin snapshot.
Source: MethaneSAT.

Figure 0.10 Methane Emissions Measurement Technology Evaluation Facility

Source: JGC Holdings.

Methane emissions reduction initiatives

(i) INPEX Corporation

Since FY2021 (April 2021–March 2022), INPEX Corporation has been researching flare reduction measures in cooperation with relevant internal departments. As part of its research and development efforts, INPEX is exploring the introduction of methane cracking technology in Japan to reduce CO_2 emissions from flare by fixing its carbon content (INPEX, 2022).

5.3.5 Summary of Corporate Initiatives on Methane Emissions Management

Managing methane emissions has increasingly become a key aspect of corporate social responsibility. However, the emissions reduction targets and figures announced by companies require standardisation and greater transparency. Currently, the scope of management and the calculation methods used are not consistently unified across companies. In the ASEAN region, whilst some companies have set GHG reduction targets and disclosed their emissions, methane emissions management has traditionally remained a secondary focus. However, in recent years, an increasing number of companies such as PETRONAS, PERTAMINA, and PTT have begun to set specific, methane-focused targets within their broader GHG strategies.

Third-party certification and methane emissions certificates are increasingly becoming a competitive differentiator. Increased interest from LNG buyers in transparent emissions

data is driving companies to act, which in turn strengthens their market position and encourages further methane emissions management.

Whilst progress has been made in developing technologies such as satellites and drones, it is important to promote the introduction of technologies beyond the development stage. In parallel with technological development, sharing the latest know how, technologies, and practices is vital to increase the interest of companies. Collaboration and the exchange of best practices between companies can accelerate the adoption of methane emission management initiatives.

The low methane emissions intensity of companies in Japan demonstrates the effectiveness of their LDAR programmes. This expertise could serve as a valuable model for accelerating methane emission management in ASEAN.

Initiatives such as the CLEAN initiative, jointly led by JERA, KOGAS, and supported by governments and international organisations, have also expanded rapidly. By 2025, the number of participating companies had grown to 27, including not only major LNG buyers but also producers and certification bodies such as MiQ. These developments are expected to further promote cross regional cooperation and advance methane transparency and reduction across the LNG value chain.

Chapter 6.
Policy Recommendations

This chapter describes possible measures and recommendations to stabilise the liquefied natural gas (LNG) market in the Association of Southeast Asian Nations (ASEAN) and surrounding Asian regions, both in terms of prices and supply–demand balances, leading to the sound development of the LNG market and the entire economy.

6.1 Define an Important Role of LNG and Natural Gas in Energy Security and Energy Transition

6.1.1 Governments to Provide Proper Guidance and Support Measures

A major obstacle to expanding greater use of natural gas and LNG for energy transition throughout Asia is the continued resistance of some governments in the developed world. International financial institutions and official export agencies of many Group of Seven (G7) members (except Japan) seem reluctant to explore government efforts to underwrite long-term use of natural gas as part of any energy transition strategy.

It is challenging to get all stakeholders in the developed world to agree that gas should be an essential part of the energy resource portfolio. The United States is pushing hard to rapidly decarbonise its power sector. In this context, some Asian countries feel pressure not to use natural gas and move straight to renewable energy. Integrating renewable energy into the electricity grid with a guarantee of reliability is often difficult and expensive. With proper government guidance and support, all the measures and proposals mentioned above will be more effective.

6.1.2 Apply Climate Mitigation Measures – Clarify International Carbon Capture and Storage Standards, Reductions of Flaring, and Other Decarbonisation Measures alongside the Value Chain

Nuclear and thermal fuels as base-load power-generation sources are needed to maintain and develop the socioeconomic system. Renewable energy is insufficient to ensure the right amount of energy when needed because it is highly variable, and, in many cases, expensive.

It seems that the public does not know that most methane emissions are from outside the energy sector including the LNG and gas industry, mostly from the agriculture sector. However, the LNG and gas industry now has to prove that it is contributing to solving the methane emissions problem rather than a cause of the problem.

Suppose CO_2 emissions from natural gas can be neutralised by actively introducing the latest technologies at each stage of the value chain, such as carbon capture and storage (CCS) and flaring reduction. For example, several LNG production projects in the United

States and regions of the world have adopted CCS, from which LNG should be able to be procured with lower greenhouse gas (GHG) intensity.

6.1.3 Equitably Evaluate Impacts of Coal to Gas Conversion in the Region

In the context of GHG, especially methane emissions management, there have been initiatives worldwide to establish frameworks to accurately measure, report, and verify volumes of such emissions alongside the LNG and natural gas value chain. At the same time, stakeholders should consider such frameworks to accurately evaluate and appreciate the net climate impacts of coal to gas conversions, especially in emerging Asian economies, where gross requirements of energy are expected to grow faster than in other regions.

By incorporating the measures described in this chapter, the authors hope that the Asian region's economies can advance to establish a healthier and more sustainable LNG market.

For the readers' reference, the following are relevant articles to promote the sound development of the LNG market from the G7 Energy and Climate Ministers' Communiqué in April 2023. This concept was also recognised in the G7 meeting in Italy in June 2024.

Relevant Items in G7 Energy Ministers' Communiqué (June 2024)

> Reaffirming our commitments in the 2023 Hiroshima Leaders' Statement, . . . the important role that increased deliveries of LNG can play and acknowledge that investment in the sector can be appropriate in response to the current crisis and to address potential gas market shortfalls provoked by the crisis. . . publicly supported investments in the gas sector can be appropriate as a temporary response, subject to clearly defined national circumstances, if implemented in a manner consistent with our climate objectives without creating lock-in effects, . . .

Relevant Items in COP28 Global Stocktake (December 2023)

> UNFCCC Parties 'Recognize that transitional fuels can play a role in facilitating the energy transition while ensuring energy security.'

Relevant Items in G7 Energy Ministers' Communiqué in 2023

'61. Methane:

> . . . an internationally aligned approach for measurement, monitoring, reporting, and verification of methane and other GHG emissions to create an international market that minimises GHG emissions across oil, gas, and coal value chains, including by minimising flaring and venting, and adopting best available leak detection and repair solutions and standards.'

'69. Natural gas and LNG

> . . . investment in the gas sector can be appropriate to help address

potential market shortfalls provoked by the crisis, subject to clearly defined national circumstances, and if implemented in a manner consistent with our climate objectives and without creating lock-in effects, for example, by ensuring that projects are integrated into national strategies for the development of low-carbon and renewable hydrogen.'

6.2 Secure Sufficient Long-term Supply Sources

6.2.1 Increase Supply from Existing LNG Production Projects and Prolong the Life Expectancy of those Projects

LNG prices must be affordable or low enough for consumers in the region to rely on LNG sustainably. Otherwise, countries could easily switch back to coal as a fuel for power generation. Therefore, it is important to secure a majority of the required volumes of LNG supply in a stable manner both for energy security and for GHG emissions reduction.

It is essential to share views with producers worldwide that consumers in the region will require more gas long term. Also, it should be noted that related infrastructure and transportation should be arranged beforehand. In that sense, the industry should take maximum advantage of existing LNG production infrastructure, which could continue producing LNG if the feed gas supply is secured. Therefore, backfill arrangements to legacy LNG projects from gas sources nearby the original sources should be further considered.

6.2.2 Expand New Supply Sources in North America, Australia, and East Africa

In recent years, vast reserves of natural gas have been discovered in many parts of the world. Amongst them, especially North America, Australia, and East Africa may be desirable from the perspective of transportation costs to Asia.

Above all, projects in the United States can be superior in per-unit costs and free on board prices, volume, and energy security.

However, it is also true that there are uncertainties like future policy change due to the election in the US as well.

6.2.3 Focus on Brownfield Opportunities and the Pacific Coast of North America

Brownfield projects are preferable to greenfield projects regarding production cost, certainty, and quickness of development. Projects in North America are relatively fast-starting, are not tied to specific natural gas fields, can source feedstock gas from the gas market, and have a low risk of missing LNG cargo shipments due to problems in the gas field.

Currently, LNG projects in North America are mainly on the Atlantic Coast. Still, considering transportation, including the passage of the Panama Canal, more attention should be paid to US projects on the Pacific Coast. However, those may encounter issues relating to local consent.

6.2.4 Consider Options in Russia after Normal Conditions Return

Russia has abundant natural gas resources, and Europe has been continuing to buy Russian LNG even during the war in Ukraine. India and China continue to purchase Russia's LNG and natural gas. Given the current situation, many economies worldwide will unlikely procure additional gas from Russia. However, if normal conditions return in the future, Russian LNG would again become options to purchase.

6.2.5 Consider Alliances with Buyers in Japan and Take Advantage of Pooling Infrastructure on the LNG Receiving Side

Japanese trading firms and utility companies can procure large volumes of LNG. Japan's LNG demand for thermal power generation may shrink significantly as it gradually restarts nuclear power plant operations after being shut down in the aftermath of the Great East Japan Earthquake in 2011. Alliances with Japanese companies could help secure LNG supply.

In addition to its current storage capacity, Japan intends to secure at least one cargo shipment of strategic buffer LNG per month during winter to prepare for possible LNG supply disruption risks. India is studying various options, including the use of abandoned gas wells and underground storage, and has contacted a few firms to help build its gas storage. In Europe, underground gas storage facilities converted from depleted gas fields have been installed in some countries. Even if natural gas and LNG supply were to cease, inventories would be sufficient for about 2 months, even in winter. Similar initiatives in ASEAN countries could help ensure a constant LNG supply during emergencies and price hike periods.

6.3 Enhance Purchasing Power

6.3.1 Aggregate Demand in the Region to Optimise Cargo Flows

The bargaining power of bulk buyers is significant. LNG sellers often need buyers in countries such as Japan, China, and Korea. In Europe, the AggregateEU initiative aggregates demand within the region. It connects buyers to sellers. However, some criticisms have been against the scheme's lack of information transparency. Southeast Asian countries could create a similar mechanism to increase the volume of purchases and to gain market influence. Seasonal or other temporary demand fluctuations in each country can also be addressed by shifting idle capacity to the most needed part within the region.

6.3.2Consider Partnerships with Buyers in Different Regions to Optimise Seasonality

Unlike Southeast Asia, there are many regions where gas demand fluctuates significantly between summer and winter. European companies buy gas in summer, store it in underground facilities, and use it in winter. A Japanese company, for example, has arranged with a company in Thailand to receive stored LNG during a high-demand period in winter. Similar approaches can be adopted to utilise large volumes of purchased LNG in a country in another country in more urgent need.

6.4 Improve Contract Terms and Conditions

6.4.1 Introduce Measures to Mitigate Fluctuations of Prices whilst Not Distorting Market Activities

Rather than straightforward limits, certain mitigation measures can be placed on excessive price fluctuations in the trading markets. The European Union has banned gas futures trading at prices higher than a certain level. Although the mechanism has not been triggered yet, there has been criticism from market players that the mechanism could distort market functions. However, if sellers sell gas to an alternative region where they can sell at a higher price, it might cause a supply shortage in Europe, in which case the suspension of trading is lifted. At least a government can indicate specific desirable ranges of purchase prices in connection with specifically targeted consuming markets so market players may try to conform. In addition, governments can initiate policy talks over possible frameworks to eliminate speculative activities in the international LNG trading market.

6.4.2 Consider Measures that Enable Larger and Longer Offtake and Delivery Commitments

One idea to avoid price volatility is stable price contracts. Long-term LNG contracts are effective in guaranteeing the security of natural gas imports. Procuring LNG at long-term stable prices would insulate the buyer from price fluctuations. The buyer is assured of access to large volumes of LNG, contributing to long-term, planned economic development. The seller can ensure a long-term recovery of its huge investment, creating a win–win situation for both parties. Spot and short-term contracts can be flexible to changing demand, though flexibility is sometimes or often expensive these days, sometimes to buyers and sellers.

Political support for concluding long-term sales and purchase agreements by utility companies would be desirable. Even if still dependent on the spot market, it is important to pursue, from a long-term point of view, the best mix of term contracts and spot transactions.

6.4.3 Reduce Destination Restrictions further to Optimise Cargo Movements

Even under long-term stable price contracts, supply and demand can be adjusted by

optimising cargo destinations, which also makes it possible to reduce transport costs. A cargo without an immediate need should be discharged at its original destination and could be diverted to a second destination with a more immediate need for gas. Since some LNG cargo travels much longer distances, the time has come to optimise cargo destinations on a grander scale.

6.5 ASEAN Stakeholders Should Respect Fundamental Methane Emissions Management Practices

Most methane emissions in the oil and gas sector result from leaks and venting and addressing these sources should be a top priority. Since no special technical requirements are needed to initiate these activities, prompt focus should be placed on leak detection and repair (LDAR) to identify fugitive emissions. Whilst LDAR can deliver results in the short term, the installation of vapor recovery units and the achievement of zero flaring should be considered as medium-term objectives.

The first step in reducing methane emissions is to quantify site-specific methane emissions. The leading best practice for methane mitigation in the oil and gas industry is accurate on-site quantification. According to the IMEO, there are significant discrepancies between emissions estimates based on generic emissions factors and actual on-site measurements. Operators must accurately identify methane emissions, as demonstrated by prior studies, to ensure the effectiveness of their mitigation efforts.

6.6 ASEAN Should Play a Proactive Role in Global Methane Emissions Management Whilst Ensuring Energy Security

ASEAN is the fourth-largest emitter of methane globally, after China, the US, and India, according to the IEA Methane Tracker. Coordinated efforts across the ASEAN region, rather than isolated national efforts, could significantly reduce global methane emissions and influence the direction of global methane emissions management initiatives.

Malaysia can lead in methane emissions management efforts.

As the region's largest natural gas producer and consumer, Malaysia's relatively low methane emissions position it as a potential leader in emissions management. Given Malaysia's influence in the ASEAN natural gas sector, its leadership in methane emissions management could quickly spread across the region.

ASEAN should leverage advanced companies and inter-corporate collaboration. Globally, companies are adopting methane emissions management through alliances and industry-led guidelines. In the ASEAN region, companies like PETRONAS, Pertamina, and PTT have already begun collaborating through initiatives like the Methane Leadership Program. These efforts could serve as a model for other ASEAN companies, fostering

regional cooperation in methane emissions management.

6.7 Standardise and Harmonise Methane Emissions Measurement Guidelines

The variety of guidelines for measuring and reporting methane emissions creates challenges for comparing emissions across frameworks and for calculating total emissions across supply chains. Standardising and coordinating these guidelines is a priority. Whilst companies disclose their reduction targets and emissions data as part of their corporate social responsibility, methods of calculation and target-setting vary. Ensuring standardisation and transparency will enhance credibility. There have been a few attempts to address the issue, mainly from Europe and the US. Some ASEAN stakeholders who can participate in this process should work to implement the content in the ASEAN region.

The significant discrepancies between IEA Methane Tracker data and national government reports highlight the need to address uncertainties in emissions factors and to identify previously unaccounted-for methane sources. These differences suggest a reliance on underestimated or imprecise emissions factors. In the ASEAN region, expanding direct measurement efforts and updating emissions factors will improve the accuracy of methane emissions data.

6.8 ASEAN Should Leverage the Expertise of Japanese Companies to Accelerate Methane Emissions Management

Japanese companies have maintained low methane emissions intensities due to long-term efforts in leak detection. ASEAN can benefit from this expertise to accelerate methane emissions control. Strengthening cooperation between ASEAN and Japanese companies, including the implementation of demonstration projects using the latest technologies, could lead to significant advancements in the region.

6.9 Show Preference for Lower Emissions Gas

During the energy transition, the continued use of natural gas must focus on cleaner practices, particularly the elimination of methane emissions gas along the supply chain. It is not only essential to reduce methane emissions domestically but also across the entire supply chain by selecting natural gas with lower methane emissions.

As public interest in methane emissions reduction grows, companies that manage methane emissions responsibly will stand out. Products with certified, well-managed, low methane emissions can offer a competitive edge, enhancing the market position.

References

ASEAN Centre for Energy (2024), 'ASEAN Energy Sector Methane Leadership Program (MLP)', 5 January. https://aseanenergy.org/post/asean-energy-sector-methane-leadership-program-mlp/

ASEAN–Korea Cooperation Fund (2024), '[Project] ASEAN - Korea Cooperation on Methane Mitigation', 5 September. https://www.aseanrokfund.com/our-works/project-asean-korea-cooperation-on-methane-mitigation (accessed 30 June 2025)

BP (2023), 'bp Expands Natural Gas Certification to 100% of its U.S. Onshore Upstream Operations', Press Release, 6 March. https://www.bp.com/en_us/united-states/home/news/press-releases/bp-expands-natural-gas-certification-to-100-percent-of-its-us-onshore-upstream-operations.html

Cheniere Energy (2024), 'Cheniere Announces Publication of Updated Peer-Reviewed LNG Life Cycle Assessment', Press Release, 12 November. https://lngir.cheniere.com/news-events/press-releases/detail/309/cheniere-announces-publication-of-updated-peer-reviewed-lng

Chevron (2021), 'Pavilion Energy, Qatarenergy and Chevron Launch GHG Reporting Methodology for Delivered LNG Cargoes', Press Release, 17 November. https://www.chevron.com/newsroom/2021/q4/pavilion-energy-qatarenergy-and-chevron-launch-ghg-reporting-methodology-for-delivered-lng-cargoes (accessed 27 August 2025)

_____ (2022a), 'Independent Analysis Recognizes Environmental Excellence', Press Release, 30 June. https://www.chevron.com/newsroom/2022/q2/independent-analysis-recognizes-environmental-excellence (accessed 27 August 2025)

_____ (2022b), *2022 Methane Report*. https://www.chevron.com/-/media/shared-media/documents/chevron-methane-report.pdf

China National Offshore Oil Corporation (CNOOC) (2021), 'CNOOC and PETRONAS Sign a Memorandum of Understanding for Strategic Collaboration', 15 March. https://www.cnooc.com.cn/art/2021/3/15/art_6261_15313137.html

Clean Energy Regulator (2025), '2023-24 Safeguard Data'. https://cer.gov.au/document/2023-24-safeguard-data-insights-0 (accessed 30 June 2025)

Council of the European Union (2025a), 'Transport, Telecommunications and Energy Council (Energy), 16 June 2025.' https://www.consilium.europa.eu/en/meetings/tte/2025/06/16/ (accessed 30 June 2025)

_____ (2025b), 'Presidency Conclusions on Strengthening the Energy Union through

Reinforcing Energy Security.' https://www.consilium.europa.eu/media/e3inzbqb/st10279en25.pdf (accessed 30 June 2025)

Department of Energy, Republic of Philippines (DOE) (2024), *Philippine Energy Plan 2023–2050.* https://doe.gov.ph/pep

Energy Institute (2023), *Statistical Review of World Energy.* https://www.energyinst.org/statistical-review/home

Environment and Climate Change Canada (2024), 'Oil and Gas Greenhouse Gas Pollution Cap – Backgrounder to CGI Regulations.' https://www.canada.ca/en/environment-climate-change/news/2024/11/oil-and-gas-greenhouse-gas-pollution-cap--backgrounder-to-cgi-regulations.html (accessed 30 June 2025)

Environmental Defense Fund (2025), 'MethaneSAT Loses Contact with Satellite', 1 July. https://www.edf.org/media/methanesat-loses-contact-satellite

European Union (2024), 'Regulation (EU) 2024/1787 of the European Parliament and the Council of 13 June 2024 on the Reduction of Methane Emissions in the Energy Sector and Amending Regulation (EU) 2019/942.' https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L_202401787 (accessed on 30 June 2025)

ExxonMobil (2021), 'ExxonMobil to Certify Natural Gas, Help Customers Meet Environmental Goals', News Release, 7 September. https://corporate.exxonmobil.com/news/news-releases/2021/0907_exxonmobil-to-certify-natural-gas-help-customers-meet-environmental-goals (accessed 27 August 2025)

_____ (2022), 'ExxonMobil Receives Top Certification for Methane Emissions Management for Natural Gas from Permian Basin', News Release, 26 April. https://corporate.exxonmobil.com/news/news-releases/2022/0426_exxonmobil-receives-top-certification-for-methane-emissions-for-natural-gas-in-permian (accessed 27 August 2025)

GHGSat (2022), 'Chevron Takes Action on Methane', Blog, 26 October. https://www.ghgsat.com/en/newsroom/chevron-takes-action-on-methane/ (accessed 27 August 2025)

Government of Canada (2024), 'Canada Gazette, Part I, Volume 158, Number 45: Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations.' https://gazette.gc.ca/rp-pr/p1/2024/2024-11-09/html/reg1-eng.html (accessed 30 June 2025)

Groupe Internationale Des Importeurs De Gaz Naturel Liquéfié (GIIGNL) (2025), *GIIGNL Annual Report 2025*.

INPEX (2022), *Sustainability Report 2022*. https://www.inpex.co.jp/english/csr/pdf/INPEX_SustainabilityReport2022_Eng.p

df

Institute of Energy Economics, Japan (IEEJ) (2024), *IEEJ Outlook 2025*. https://eneken.ieej.or.jp/data/12114.pdf

Intergovernmental Panel on Climate Change (IPCC) (1988), 'History of the IPCC'. https://www.ipcc.ch/about/history/

_____ (2021), 'IPCC Sixth Assessment Report, Working Group 1: The Physical Science Basis, Chapter 7: The Earth's Energy Budget, Climate Feedbacks and Climate Sensitivity, Table 7.15.' https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter07.pdf

_____ (2024), 'IPCC Agrees on the Set of Scientific Reports for the Seventh Assessment Cycle', Newsroom, 20 January. https://www.ipcc.ch/2024/01/19/ipcc-60-ar7-work-programme/ (accessed 19 January 2024)

International Energy Agency (IEA) (2025a), *Gas Market Report, Q3 — 2025*. https://iea.blob.core.windows.net/assets/119378b2-8d56-49c7-9907-9ee7a516fddd/GasMarketReport-Q32025.pdf

_____ (2025b), 'Global Methane Tracker 2025'. https://www.iea.org/reports/global-methane-tracker-2025 (accessed 27 August 2025)

International Gas Union (IGU) (2022), *Wholesale Gas Price Survey 2022 Edition*. https://www.igu.org/resources/2022-wholesale-price-report/

Japan Organization for Metals and Energy Security (JOGMEC) (2022), 'Study on Methane Measurement Technologies using Aircraft in collaboration with ANA and JAXA – Aiming for the Social Implementation of Greenhouse Gas Measurement Methods from the Sky'. (in Japanese). https://www.jogmec.go.jp/news/release/news_08_00027.html (accessed 24 November 2022)

_____ (2023), 'Recommended Guideline for Greenhouse Gas and Carbon Intensity Accounting frameworks for LNG/Hydrogen/Ammonia Projects (JOGMEC CI Guideline)' https://www.jogmec.go.jp/content/300384406.pdf (accessed 27 August 2025)

_____ (2024), 'JOGMEC published the Results of the CLEAN initiative, "CLEAN Annual Report" at the LNG Producer-Consumer Conference 2024', News Release, 7 October. https://www.jogmec.go.jp/english/news/release/news_08_00019.html

_____ (2025), 'Announcement of Joint Statements at LNGPCC2025' https://www.jogmec.go.jp/english/news/release/news_08_00041.html

JGC Holdings Corporation (2023a), 'JGC Group Becomes First Japanese Company in Aiming for Zero, Targeting Methane Emissions', News Release, 7 March.

https://www.jgc.com/en/news/2023/20230307_2.html (accessed 27 August 2025)

_____ (2023b), 'JGC Awarded Contract for First Nearshore Floating LNG Plant in Malaysia', News Release, 6 January. https://www.jgc.com/en/news/2023/20230106.html

MethaneSAT (2020), 'About MethaneSAT'. https://www.methanesat.org/purpose

Ministry of Ecology and Environment and State Administration for Market Regulation (2024), 'Emission Standard of Coalbed Methane (coal mine gas).' https://www.mee.gov.cn/ywgz/fgbz/bz/bzwb/dqhjbh/dqgdwrywrwpfbz/202412/W020241211363785242577.pdf (accessed on 30 June 2025)

Ministry of Economy, Trade and Industry (2023), 'LNG Producer-Consumer Conference 2023 Held', News Release, 19 July. https://www.meti.go.jp/english/press/2023/0719_002.html

Mubadala Energy (2022), 'Mubadala Energy Reports Further Positive Momentum in its Southeast Asia Portfolio with Another New Gas Discovery in Malaysia', Media Release, 21 September. https://mubadalaenergy.com/news/mubadala-energy-reports-further-positive-momentum-in-its-southeast-asia-portfolio-with-another-new-gas-discovery-in-malaysia/

New Fortress Energy (2024), 'New Fortress Energy Achieves First LNG for its Fast LNG Asset', Press Release, 19 July. https://ir.newfortressenergy.com/news-releases/news-release-details/new-fortress-energy-achieves-first-lng-its-fast-lng-asset

Offshore Technology (2022), 'Shell to Invest $66m to Build LNG Import Terminal in the Philippines', News, 9 June. https://www.offshore-technology.com/news/shell-lng-terminal-philippine/

Pavilion Energy (2020), 'Pavilion Energy and Qatar Petroleum Sign Strategic LNG Supply Agreement for Singapore' https://www.pavilionenergy.com/en/media/pavilion-energy-and-qatar-petroleum-sign-strategic-lng-supply-agreement-for-singapore Original press release link no longer available (accessed December 2025).

PERTAMINA (2023), 'Indonesia's PERTAMINA and Japan's JOGMEC Joint Effort on Methane Emission Measurement and Quantification to Accelerate Energy Transition', News Release. https://www.pertamina.com/en/news-room/news-release/indonesia.s-pertamina-and-japan.s-jogmec-joint-effort-on-methane-emission-measurement-and-quantification-to-accelerate-energy-transition (accessed 27 August 2025)

Petrolife Aero LNG (2020), 'Malaysia to Open Up LNG Import Market in January', 1 October. https://petrolife.com.my/malaysia-to-open-up-lng-import-market-in-january/

PETRONAS (2021a), 'Key ASEAN Energy Players to Intensify Collaboration in Addressing Methane Emissions', Media Release, 27 https://www.petronas.com/media/media-

releases/petronas-key-asean-energy-players-intensify-collaboration-addressing-methane (accessed 27 August 2025)

_____ (2021b), 'PETRONAS Promotes Transparency On Climate-Related Disclosures', Media Release, 27 October. https://www.petronas.com/media/media-releases/petronas-promotes-transparency-climate-related-disclosures (accessed 27 August 2025)

_____ (2022), 'Strengthens Methane Emissions Management, Boosts Decarbonisation Efforts via New Alliances at COP27', Media Release, 11 November. https://www.petronas.com/media/media-releases/petronas-strengthens-methane-emissions-management-boosts-decarbonisation (accessed 27 August 2025)

_____ (2022a), 'PETRONAS Withdraws from Yetagun Field Offshore Myanmar', Media Release, 29 April. https://www.petronas.com/media/media-releases/petronas-withdraws-yetagun-field-offshore-myanmar-0

_____ (2022b), 'PETRONAS Expands Strategic Alliance with YPF for Growth Opportunities in Argentina', Press Release, 1 September. https://www.petronas.com/media/press-release/petronas-expands-strategic-alliance-ypf-growth-opportunities-argentina

_____ (2022c), 'PETRONAS Declares Force Majeure on Gas Supply to MLNG Dua', Press Release, 8 October. https://www.petronas.com/media/press-release/petronas-declares-force-majeure-gas-supply-mlng-dua

_____ (2023), 'PETRONAS, JOGMEC to Cooperate in Energy Transition Initiatives', Media Release, 6 March. https://www.petronas.com/media/media-releases/petronas-jogmec-cooperate-energy-transition-initiatives

_____ (2024), 'PETRONAS and Partners to Advance Methane Emissions Reduction Efforts in Southeast Asia Region', Media Release, 2 October. https://www.petronas.com/media/media-releases/petronas-and-partners-advance-methane-emissions-reduction-efforts-southeast

_____ (2025), *Integrated Report 2024*. https://www.petronas.com/sites/default/files/uploads/content/2025/PETRONAS-Integrated-Report-2024.pdf

Praiwan, Y. (2021a), 'EGAT, PTT Weigh Up Gas Project', *Bangkok Post*, 21 April. https://www.bangkokpost.com/business/2103039/egat-ptt-weigh-up-gas-project

_____ (2021b), 'EGAT Allocates B20bn for LNG Terminal', *Bangkok Post*, 5 July. https://www.bangkokpost.com/business/2143395/egat-allocates-b20bn-for-lng-terminal

_____ (2021c), 'NEPC Okays LNG Imports', *Bangkok Post*, 5 August.

https://www.bangkokpost.com/business/2160147/nepc-okays-lng-imports

PV Gas (2023), 'PV Gas Received First LNG Cargo at Thi Vai LNG Terminal', *PV GAS News*, 10 July. https://www.pvgas.com.vn/en-us/news/pv-gas-received-first-lng-cargo-at-thi-vai-lng-terminal

QatarEnergy (2022), *Your Energy Transition Partner: Sustainability Report.* https://www.qatarenergy.qa/en/MediaCenter/Publications/QatarEnergy%202022%20Sustainability%20Report.pdf

Sarawak Government (2017), 'Sarawak's Own Oil And Gas Firm Petros Officially Formed', *Borneo Post*, 8 August. https://sarawak.gov.my/web/home/news_view/244/8798/

Shell (2022), 'Shell Invests in Rosmari-Marjoram in Sarawak, Malaysia', Media Release, 5 September. https://www.shell.com/media/news-and-media-releases/2022/shell-invests-in-rosmari-marjoram-in-sarawak-malaysia.html

Shell Global (2022), 'Shell Completes Sale of Interest in Malampaya, Philippines', Media Release, 1 November. https://www.shell.com/media/news-and-media-releases/2022/shell-completes-sale-of-interest-in-malampaya-philippines.html

TotalEnergies (2022a), 'AUSEA: The Innovative Technology for Reducing Our Carbon and Methane Emissions'. https://totalenergies.com/projects/innovation-and-rd/ausea-innovative-technology-reducing-our-carbon-and-methane-emissions

_____ (2022b), 'Methane Emissions Reduction: TotalEnergies Implements a Worldwide Drone-Based Detection Campaign', Press Release, 16 May. https://totalenergies.com/media/news/press-releases/methane-emissions-reduction-totalenergies-implements-worldwide-drone (accessed 27 August 2025)

_____ (2024), 'TotalEnergies and ONGC in India Join Forces to Detect and Measure Methane Emissions', Press Release, 6 February. https://totalenergies.com/media/news/press-releases/totalenergies-and-ongc-india-join-forces-detect-and-measure-methane

United Nations Environment Programme (UNEP) (2023), 'An Eye on Methane'. https://wedocs.unep.org/bitstream/handle/20.500.11822/44129/eye_on_methane.pdf

US EPA (2022) 'Understanding Global Warming Potentials' https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

US Department of Energy (2024), *GRID Modernization Strategy.* https://www.energy.gov/sites/default/files/2024-12/Grid%20Modernization%20Strategy%202024.pdf

Velasco, M. (2021), 'DOE to Invest ₱502 B for Gas Extraction', *Manila Bulletin*, 6 December. https://mb.com.ph/2021/12/05/doe-to-invest-p502-b-for-gas-extraction/

Xinhua (2024), 'China Launches New Satellite to Monitor Methane Emissions', 12 November.
https://english.www.gov.cn/news/202411/12/content_WS673292fcc6d0868f4e8ecd41.html (accessed 30 June 2025)