ERIA Research Project Report FY2024, No. 27

Study on Different Impacts of LNG Market Shifts on ASEAN

by

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Preface

Whilst liquefied natural gas (LNG) has numerous advantages and can enhance Asia's economic competitiveness, environmental quality, and energy security, there are several issues and challenges to promoting LNG in the region, particularly during the relatively stable period of 2023 and 2024 after the global energy crisis in 2022. In the 2022 study conducted by the Economic Research Institute for ASEAN and East Asia (ERIA), titled 'Mitigating Extreme Volatility of LNG Prices in ASEAN: Impacts of high LNG prices on Southeast Asia,' the following policy recommendations were presented:

1. Secure sufficient long-term supply sources
2. Enhance purchasing power
3. Alter contract terms and conditions
4. Adjust the limitations and restrictions in climate goals

This 'Study on Different Impacts of LNG Market Shifts on ASEAN', investigates what has happened to the LNG market in ASEAN and surrounding regions for the past several years, especially the extreme volatility of spot LNG prices and its impacts on the various economies and stakeholders in the region – some are producers, consumers, and producing and consuming economies. The region, where the LNG industry has grown significantly in the last several years, faces increasing challenges in balancing its energy security, affordability, sustainability, and energy transition in its economic development context.

The authors hope this study will provide new insights for the sound development of the LNG market in the whole Asian region.

Hiroshi Hashimoto

Leader of the Working Group

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The presentations at the two events – from the region's industry players, government authorities, and stakeholders from other areas which 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; Rick Westerdale, Executive Director of the Energy Future Initiative 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.

Hiroshi Hashimoto

Leader of the Working Group

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List of Abbreviations and Acronyms

APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
Bcm	billion cubic metres
Bcf/d	billion cubic feet per day
Bcm/y	billion cubic metres per year
CCS	carbon capture and storage
CY	calendar year
DES	delivered ex-ship
DOE	Department of Energy
EGAT	Electricity Generating Authority of Thailand
EIA	Energy Information Administration
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
GW	gigawatt
IEEJ	Institute of Energy Economics, Japan
km	kilometre
Lao PDR	Lao People's Democratic Republic

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
PDP	Power Development Plan (Viet Nam)
PGC	Potential Gas Committee
PJ	petajoule
Tcf	trillion cubic feet
TTF	Title Transfer Facility
US	United States

Introduction

After several years of relatively low and extremely low spot liquefied natural gas (LNG) prices (in 2020), the world of LNG experienced a prolonged period of unprecedented extremely high levels of spot LNG prices until the end of 2022. Since the first half of 2023, the market has seen softening of prices, but still relatively high with some potential risk factors of rising again.

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, more stable and healthy development of the regional LNG market could be possible.

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 6 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.

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 20% in 2021 to 25% in 2050, according to the *IEEJ Outlook 2024*.

With modest domestic production growth in ASEAN, Asia's (including other areas of Asia) import dependency could rise significantly from around 30% to nearly 50% by 2050. Therefore, 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 following the sanctioning of 240 million tonnes per year of capacity from 2017 to the first half 2024. Notably, for those projects that got final investment decisions during the period, more than half of the assumed volumes have not decided their final destinations. 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 ready LNG users. 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.

For example, Japanese LNG importers (city gas and electric power companies) who have additional LNG volumes, trading houses, shipping companies, and upstream developers, in collaboration with Japanese commercial banks and government organisations, have already been active in other countries –including ASEAN countries – to create additional LNG demand, sometimes competing and sometimes collaborating with LNG players from other countries. This could significantly increase LNG consuming points to make market activities more flexible. Increasing transactions between more players should make it less difficult for them to create Asia's LNG price indexes.

Although there are a lot of challenges – such as the balance between vertical integration of the LNG value chain and increasing flexibility of LNG transactions, credit ratings of diversified parties to be involved, and different technical standards in different countries – Japanese players are expected to continue contributing to the development of the LNG market, in collaboration with national and private energy companies, and regional organisations in the ASEAN region.

The global 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 – starting from extremely low spot LNG prices in the first half of 2020, stagnant project development activities with few investment decisions in the year, the following extreme volatility of spot LNG prices at the beginning of 2021, and culminating in the persistently high prices after the second half of the year. Then, the developments were followed by extremely higher prices in the period after the Russian invasion of Ukraine. The global market has calmed since the beginning of 2023, thanks 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.

During the past turbulent years, the world again reminded that LNG was 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 industry and governments will have to find ways to pursue harmonised goals of economic prosperity and energy transition with cleaner energy sources. Some economies in the region also took advantage of competitive spot LNG prices to introduce LNG in 2020 and later experienced difficult market conditions in 2022. The ASEAN region saw increased LNG imports, with new importers joining the LNG market in 2023.

The COVID-19 pandemic and the decarbonisation agenda have added extra complexity to developing a flexible LNG market in Asia. Although the situation has constantly evolved, the study cannot ignore those elements and tries to update them to the maximum extent.

This study 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 also 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.

For the Asian LNG market to flourish, new supply and demand centres need to grow. The full range of market participants, from sellers and traders to final users, such as power utilities, need confidence that LNG can play a vital role in the energy and transition agenda in the region for decades.

Executive Summary and Key Findings

This study report begins by analysing recent trends in the volatile global liquefied natural gas (LNG) markets, focusing on price fluctuations driven by rapidly shifting market balances. The authors observe that LNG prices now exhibit sharper and faster movements than in previous years, often reaching extreme highs or lows, and occasionally entering negative territory in some regions, where sellers pay offtakers to take deliveries.

The report examines gas supply and demand dynamics in Southeast Asia, highlighting the interplay between economic growth and the global energy crisis. It considers the prospects for natural gas and LNG market development in the region, which includes traditional gas-producing and LNG-exporting nations, as well as emerging LNG importers. In mid-2023, the Philippines and Viet Nam joined the ranks of LNG-importing countries, with their market growth contingent on global LNG developments. Myanmar, however, ceased LNG imports 3 years ago due to market instability and affordability issues.

Within ASEAN, traditional LNG exporters like Brunei Darussalam, Indonesia, and Malaysia are key players. Indonesia and Malaysia, while advancing new LNG production projects with innovative business models, have also integrated LNG usage domestically. These economies are navigating the complexities of energy transition, aiming to increase LNG and natural gas utilisation alongside expanded renewable energy deployment and energy efficiency measures.

The report delves into factors amplifying price volatility, such as the European Union's pivot toward greater LNG imports in response to the energy crisis, particularly after the Russian invasion of Ukraine. It also addresses fundamental pre-existing market pressures, including China's rapid natural gas market growth, which has contributed to seasonal winter tightness. In contrast, South Asia, led by India, presents a different dynamic in its approach to LNG compared to Southeast Asia and China.

The study also highlights short-term disruptions in LNG production, which have become more frequent and impactful, though often underreported. It explores historical and regional differences in wholesale gas pricing, shedding light on the diverse market landscapes.

The report underscores the role of LNG supply from the United States, a critical source for emerging global LNG consumers. While US LNG supplies pose certain challenges, their flexibility in pricing and destination, coupled with their significant potential, makes them an attractive option for sustaining economic growth in Southeast Asia and beyond.

The report provides a comprehensive set of recommendations aimed at enhancing the role of LNG and natural gas in energy security and the energy transition, particularly in the ASEAN region. The key recommendations include:

Clearly Define the Role of LNG and Natural Gas

- **Governments should provide proper guidance and support**: Implement measures for effective greenhouse gas (GHG) management and reduction.
- **Flexibly apply climate mitigation measures**: Establish clear international standards for carbon capture and storage (CCS), flaring reduction, and other decarbonisation technologies across the value chain.
- **Equitably evaluate coal-to-gas impacts**: Assess the environmental and economic implications of coal-to-gas conversions within the region.

Secure Long-term Supply Sources

- **Optimise existing projects**: Enhance production from current LNG facilities and extend their operational lifespans.
- **Expand new supply sources**: Explore opportunities in North America, Australia, and East Africa, with an emphasis on brownfield projects and the Pacific Coast of North America.
- **Future options**: Reevaluate Russian supply options once geopolitical conditions stabilise.
- **Form alliances**: Collaborate with Japanese buyers and leverage shared infrastructure on the LNG receiving side.

Enhance Purchasing Power

- **Aggregate regional demand**: Pool demand to streamline cargo flow across the region.
- **Seasonal optimisation**: Partner with buyers in other regions to take advantage of seasonal differences in demand.

Improve Contract Terms and Conditions

- **Price stability**: Introduce mechanisms to mitigate price volatility without disrupting market dynamics.
- **Commitment flexibility**: Enable longer and larger offtake and delivery commitments to improve reliability.
- **Optimise cargo movements**: Reduce destination restrictions to allow greater flexibility in cargo routing and delivery.

The authors express hope that these recommendations will foster meaningful discussions and initiatives to strengthen and grow the LNG industry, with a particular focus on sustainable and efficient development in the ASEAN region.

Chapter 1

A Relatively Calm Period of LNG Prices with Signs of Destabilisation

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 in 2023 and 2024 due to mild weather conditions and improving supply fundamentals, especially in Europe. However, until 2026 when Qatar will start exporting LNG from the North Field Expansion, 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 amount of LNG cargo crossing the Panama Canal and the Suez Canal has decreased due to lower water levels and political tensions, respectively. Consequently, more LNG cargo is 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 (Q2 2024) that shipping constraints due to these choke point risks could lead to higher LNG supply costs.

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. Countries like Viet Nam and the Philippines have started and have been increasing the 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.

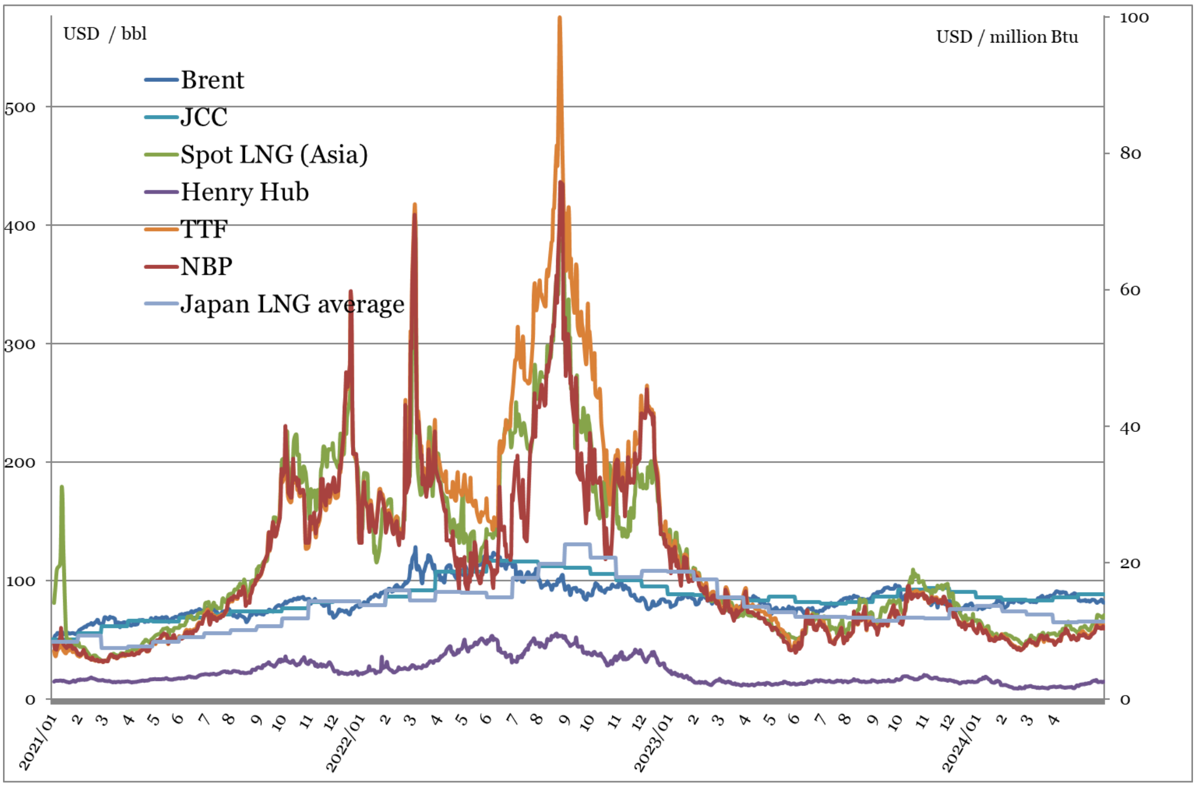
2. Global LNG and Gas Prices Move Faster and Wider

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, the 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 1.1).

Figure 1.1. Spot LNG Prices (Jan 2021–May 2024)



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 and 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 USD72 per 1 million British thermal units (MBtu) (EUR227.201 per megawatts per hour [MWh]) on fears of Russian pipeline gas supply disruptions, accompanied by assessed Asian spot LNG prices, which temporarily soared to USD85 per MBtu.

As the 2022 summer season began, the TTF rose due to Nord Stream's throughput reduction, marking USD99 per MBtu (EUR339.196/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-USD10s per MBtu range by the middle of July 2023 and have remained around the level since then. This stability is also due to relatively moderate LNG demand of Japan and China.

Table 1.1. 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	USD56/MBtu	USD54/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	USD44/MBtu	USD60/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	USD84.8/MBtu	USD72/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

	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
August 2022	USD71/MBtu	USD94.2/MBtu
	Rise of European spot prices	Supply shortages (concerns) - Maintenance of Nord Stream 2 - Maintenance of gas fields in Norway
December 2022	USD40/MBtu	USD46.1/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 USD10/MBtu)	

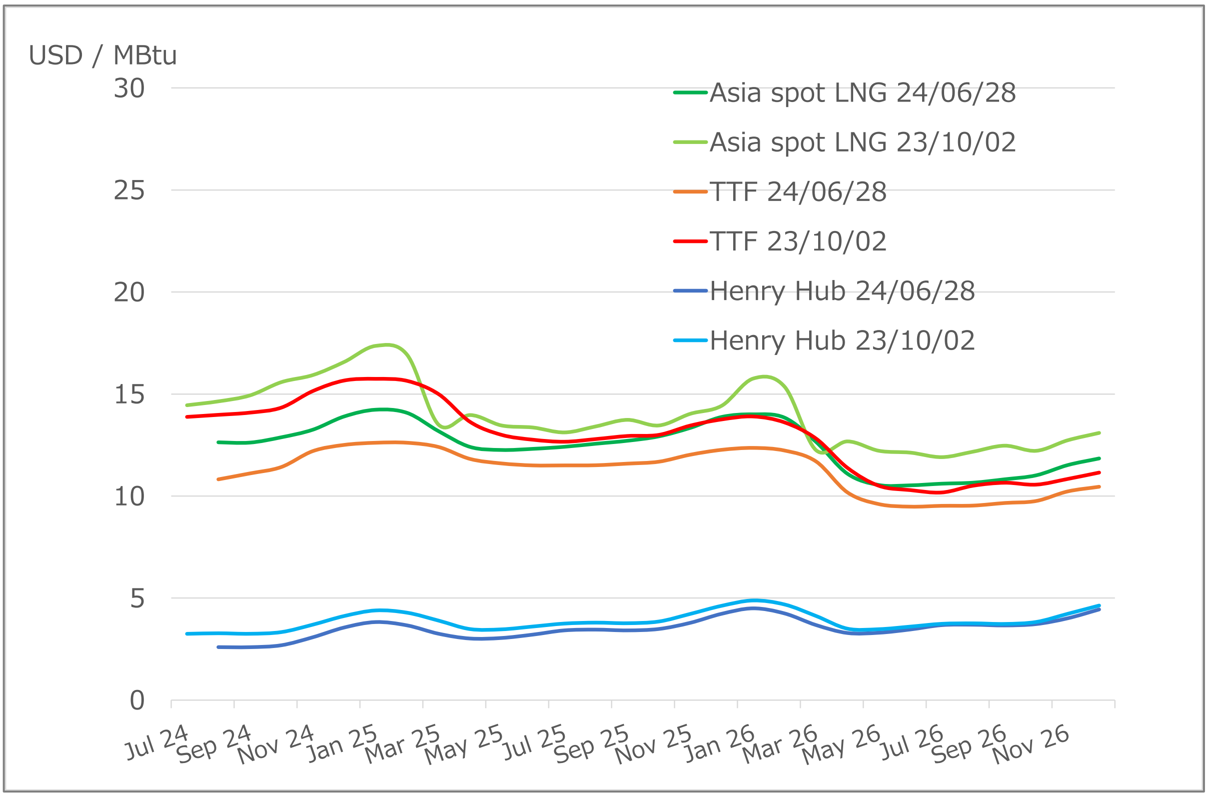
MBtu = million British thermal unit, LNG = liquefied natural gas, TTF = Title Transfer Facility.
Source: Analysis by Institute of Energy Economics, Japan.

3. Market Sentiments Can Shift Quickly

Reflecting the relatively stable current 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 1.2). 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 0.1. Changes in Asia Spot LNG, TTF, Henry Hub Forward Curves



MBtu = 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

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 started to import LNG, while 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.

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.

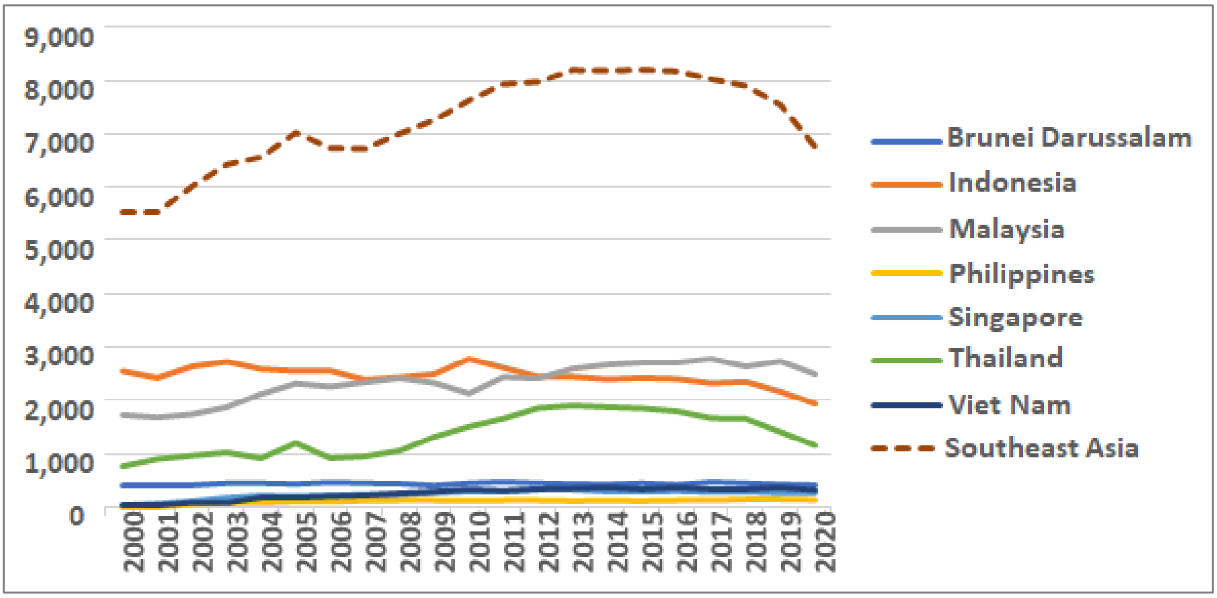
Even in the ASEAN region, where energy consumption continues to increase, more and more countries have been setting carbon neutrality goals since the United Nations Climate Change Conference (COP26) in the United Kingdom in 2021. So far, eight of the 10 ASEAN Member States – Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, 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).

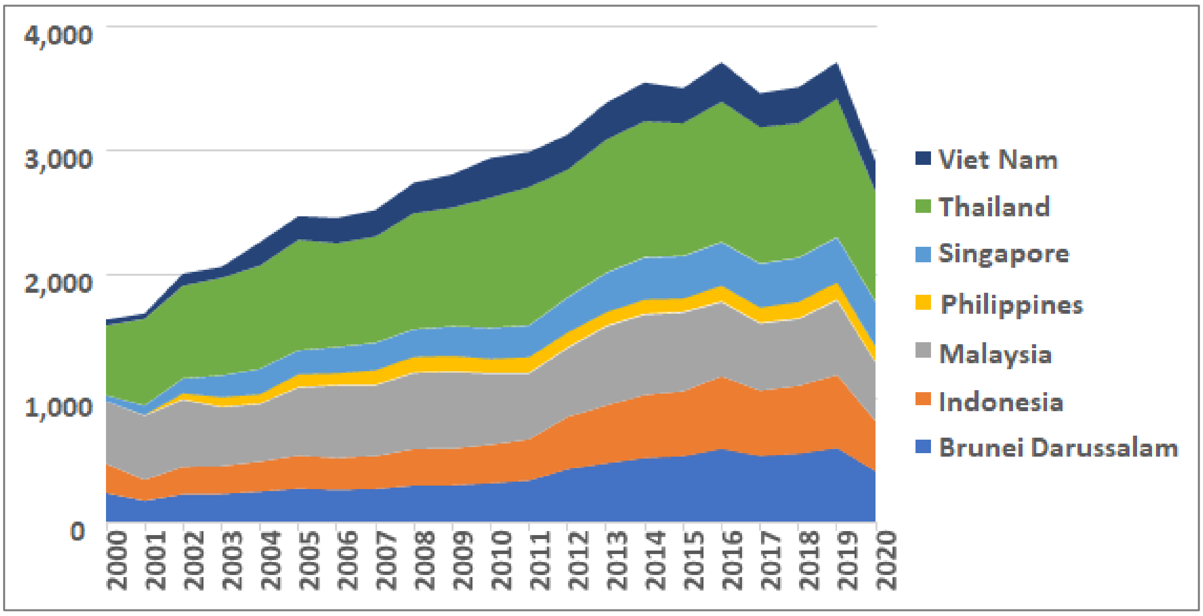
As of 2021, natural gas accounted for 10% of final energy consumption and 20% of primary energy supply in ASEAN. Going forwards, it will be consumed mainly to meet the high-temperature heat demand of industrial furnaces, which are extremely difficult to electrify in the industry sector, and as feedstock for petrochemicals. According to the *IEEJ Outlook 2024*, either in the 'Optimal Case' where there are no constraints for the share of renewable energy or domestic supply of natural gas, or in the 'Gas Supply Constraints Case' where the domestic supply of natural gas remains flat from 2019, the portion of natural gas will increase.

Figure 2.1. Total Gas Supply by Economy in Southeast Asia (PJ)



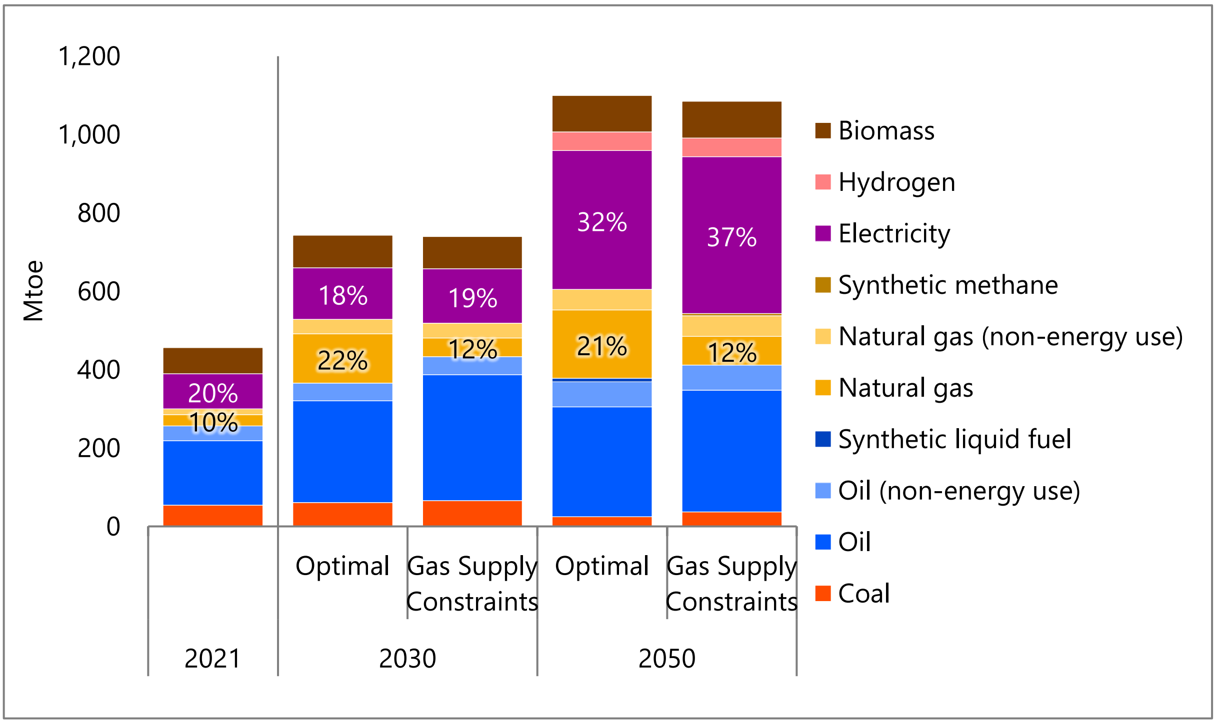
PJ = petajoule.
Source: Based on data from the Asia Pacific Energy Resource Centre.

Figure 2.2. 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 2.3. Final Energy Consumption in ASEAN

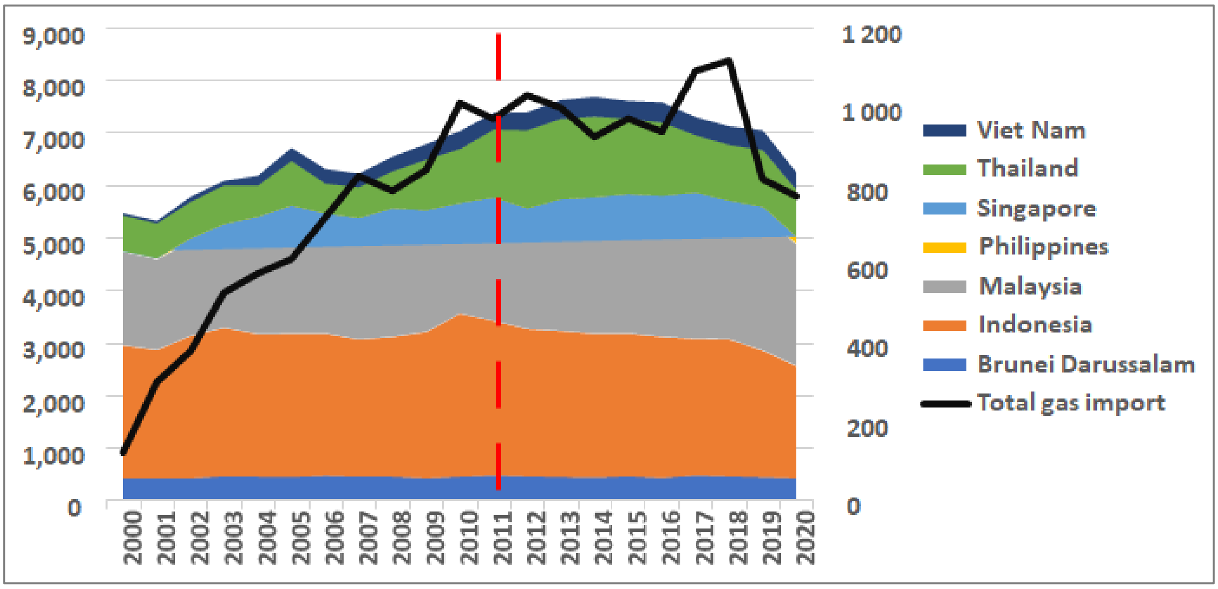


Mtoe = million tonnes of oil equivalent.
Source: IEEJ (2023).

1.2. Production and Import 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 2.4. 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.

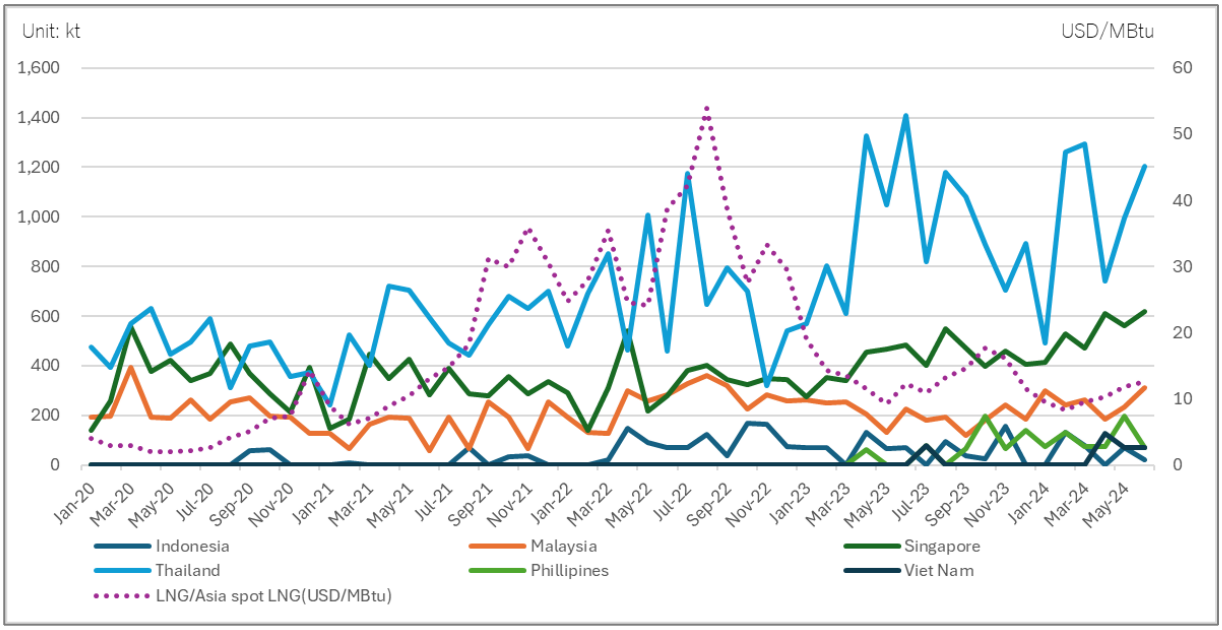
1.3. LNG Spot Prices and Imports

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 2.5. LNG Spot Prices and Imports by Country



kt = kilotonne, MBtu = metric million British thermal unit.

Source: Based on data from Cedigaz and Investing.com. (Access date is on 31st of August 2024) https://jp.investing.com/commodities/lng-japan-korea-marker-platts-futures-historical-data

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. Thailand

2.1. Economy and Energy Demand Outlook

According to the *IEEJ Outlook 2024*, Thailand's primary energy consumption is forecast to increase by an average of 1.1% per year The forecast is based on an assumed economic growth rate (2015 prices) of 3.1% annually from 2021 to 2050. The energy mix in 2050 will comprise 6.7% coal, 38% oil, 22% natural gas, 3.5% nuclear, 0.6% hydro, 21% biomass and waste, 3.8% solar, wind, etc. (Table 2.1).

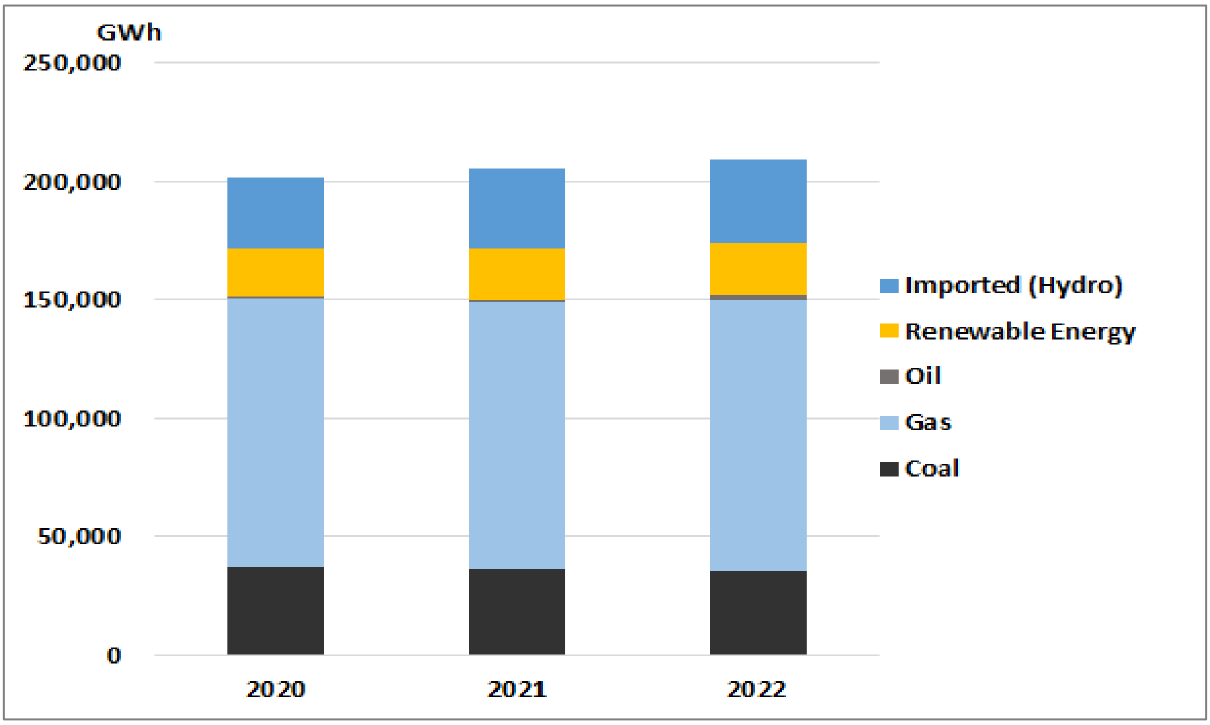
Table 2.1. Primary Energy Consumption in Thailand

	Mtoe							Shares (%)		
	1990	2000	2010	2021	2030	2040	2050	1990	2021	2050
Total*1	42	73	118	130	147	165	179	100	100	100
Coal	3.8	7.7	16	16	13	13	12	9.0	12	6.7
Oil	18	32	45	56	62	67	69	43	43	38
Natural gas	5.0	17	33	34	39	41	40	12	26	22
Nuclear	-	-	-	-	-	1.8	6.2	-	-	3.5
Hydro	0.4	0.5	0.5	0.4	0.9	1.0	1.1	1.0	0.3	0.6
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar, wind, etc.	-	-	0.0	0.7	1.8	4.2	6.8	-	0.6	3.8
Biomass and waste	15	15	23	21	26	32	38	35	16	21
Hydrogen	-	-	-	-	-	-	-	-	-	-

Mtoe = million tonnes of oil equivalent.
Note: *1 Trade of electricity and heat not shown.
Source: IEEJ (2023).

In the power sector, generation from coal declined by over 3% between 2020 and 2022 (Figure 2.6). But generation from gas increased marginally. During the same period, Thailand increased importing hydropower from the Lao PDR, enabling the nation to meet the growing electricity demand without substantially expanding the generation from coal or gas.

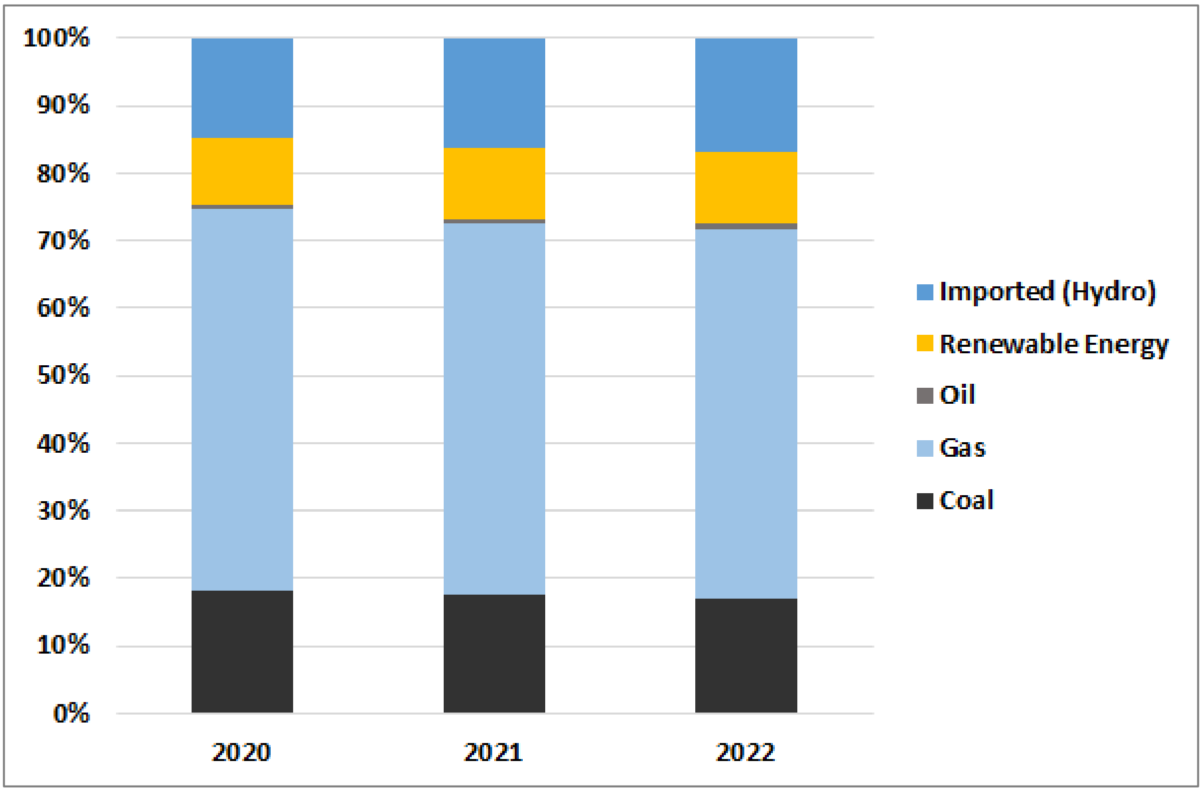
Figure 2.6. Annual Power Generation by Fuel Type, 2020–2022 (GWh)



GWh = gigawatt-hour.
Source: Based on data from the Energy Policy and Planning Office, Ministry of Energy Thailand.

Gas remains Thailand's dominant fuel for power generation, although the share declined from 57% in 2020 to 55% in 2022 (Figure 2.7). The share of imported hydroelectric power from the Lao PDR increased from 15% to 17% during the same period, enabling Thailand to meet growing electricity demand without substantially increasing coal or LNG imports. This trend may be attributed to the government's policy aimed at reducing the reliance on gas whilst simultaneously boosting the role of renewable energy in the power generation mix.

Figure 2.7. Share of Annual Power Generation by Fuel Type, 2020–2022 (%)



Source: Based on data from the Energy Policy and Planning Office, Ministry of Energy Thailand.

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.

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 THB102,165 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.

2.3. 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.

3. Malaysia

3.1. Economy and Energy Demand Outlook

The *IEEJ Outlook 2024* forecasts Malaysia's primary energy consumption to increase by an average of 1.7% per year, based on an assumed economic growth rate (2015 prices) of 3.6% annually from 2021 to 2050. The energy mix in 2050 will comprise 14% coal, 21% oil, 58% natural gas, 2.3% nuclear, 2.3% hydro, 1.1% biomass and waste, and 1.8% solar, wind, etc. (Table 2.2).

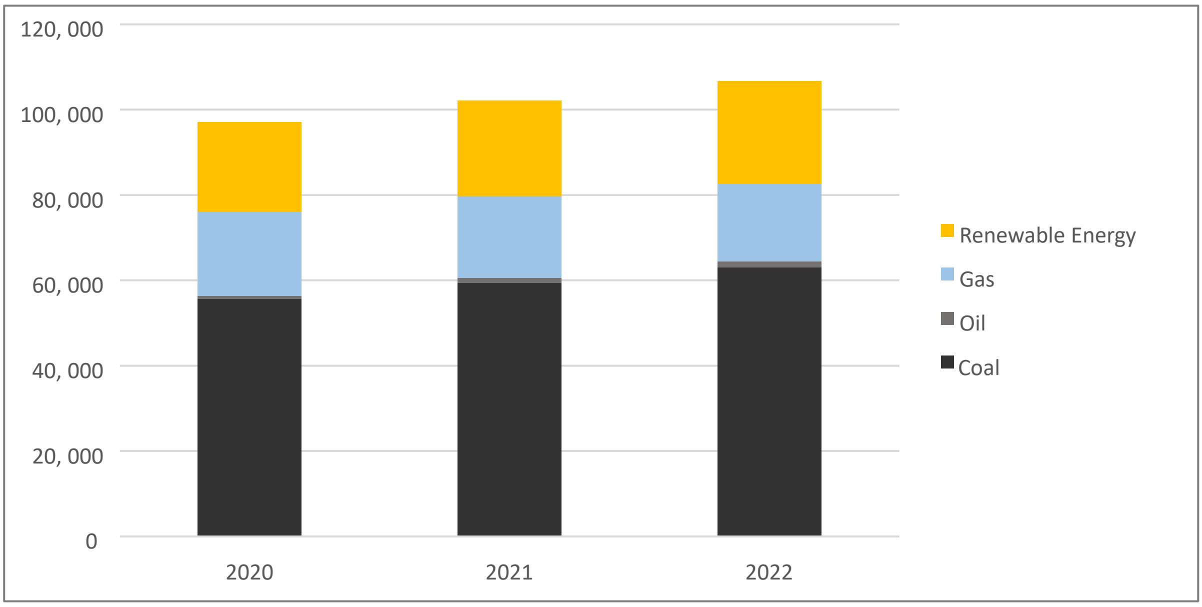
Table 2.2. Primary Energy Consumption in Malaysia

	Mtoe							Shares (%)		
	1990	2000	2010	2021	2030	2040	2050	1990	2021	2050
Total[*1]	21	48	72	95	129	146	156	100	100	100
Coal	1.4	2.3	15	23	24	24	22	6.4	24	14
Oil	11	19	25	26	35	35	32	54	27	21
Natural gas	6.8	25	31	43	64	77	90	32	45	58
Nuclear	-	-	-	-	-	3.7	3.7	-	-	2.3
Hydro	0.3	0.6	0.6	2.7	3.0	3.4	3.5	1.6	2.8	2.3
Geothermal	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	-	0.2	0.4	1.5	2.8	-	0.2	1.8
Biomass and waste	1.2	1.2	0.8	1.2	1.3	1.5	1.7	5.8	1.3	1.1
Hydrogen	-	-	-	-	-	-	-	-	-	-

Mtoe = million tonnes of oil equivalent.
Note: *1 Trade of electricity and heat not shown.
Source: IEEJ (2023).

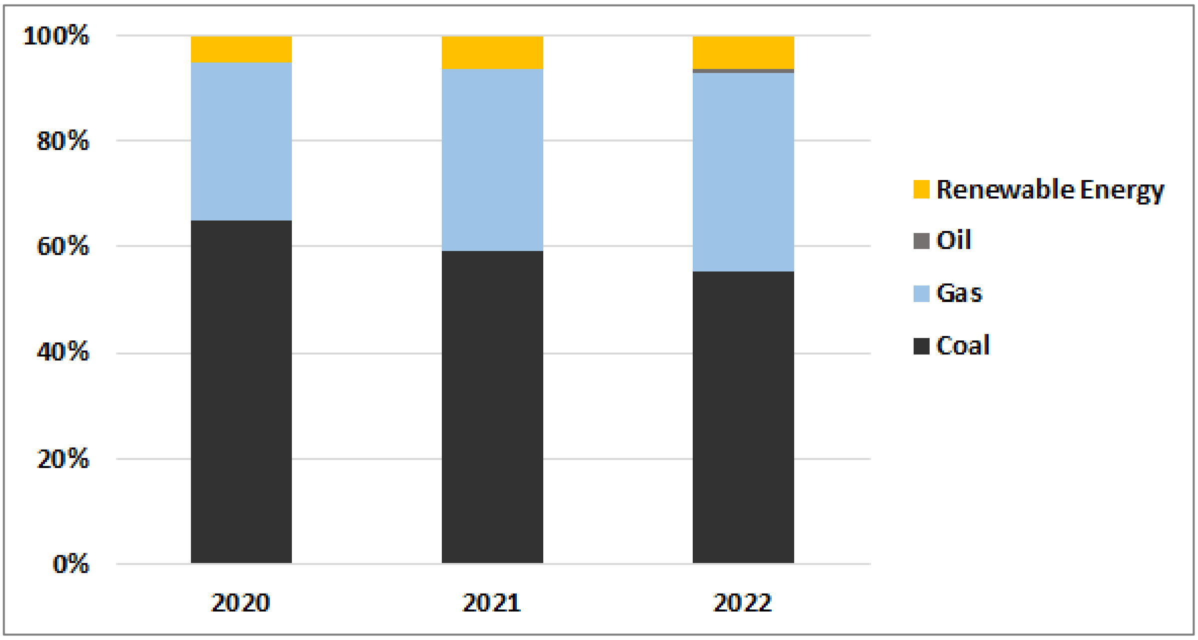
Figure 2.8 and Figure 2.9 illustrate the shift in annual power generation by fuel type and in market share within Malaysia's power sector between 2020 and 2022, with gas gaining share despite rising prices. The gas share increased from 30% to 37%, whilst coal share decreased from 65% to 56%. Malaysia's domestic gas production grew during this period, underpinning the country's ever-growing demand for the power and industry sectors.

Figure 2.8. Annual Power Generation by Fuel Type, 2020–2022 (GWh)



GWh = gigawatt-hour.
Source: Based on data from Ember.

Figure 2.9. Share of Annual Power Generation by Fuel Type, 2020–2022 (%)



Source: Based on data from the Grid System Operator, Malaysia.

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, 2024).

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.

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 2.3. 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 govt. 5%, Mitsubishi 5%)
MLNG II (Dua) (Trains 4-6)	9.6	1995	MLNG Dua (PETRONAS 80%, Mitsubishi 10%, Sarawak state govt. 10%)
MLNG III (Tiga) (Trains 7, 8)	7.6	2003	MLNG Tiga (PETRONAS 60%, Sarawak state govt. 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 govt. 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 govt.

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, 2023). 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.

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 km).

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.

4. The Philippines

4.1. Economy and Energy Outlook

The *IEEJ Outlook 2024* forecasts the Philippines' primary energy consumption to increase by an average of 2.7% per year, based on an assumed economic growth rate (at 2015 prices) of 4.8% annually from 2021 to 2050. The energy mix in 2050 will comprise 22% coal, 42% oil, 16% natural gas, 9.9% geothermal, 1.1% hydro, 7.6% biomass and waste, and 2.3% solar, wind, etc. (Table 2.4).

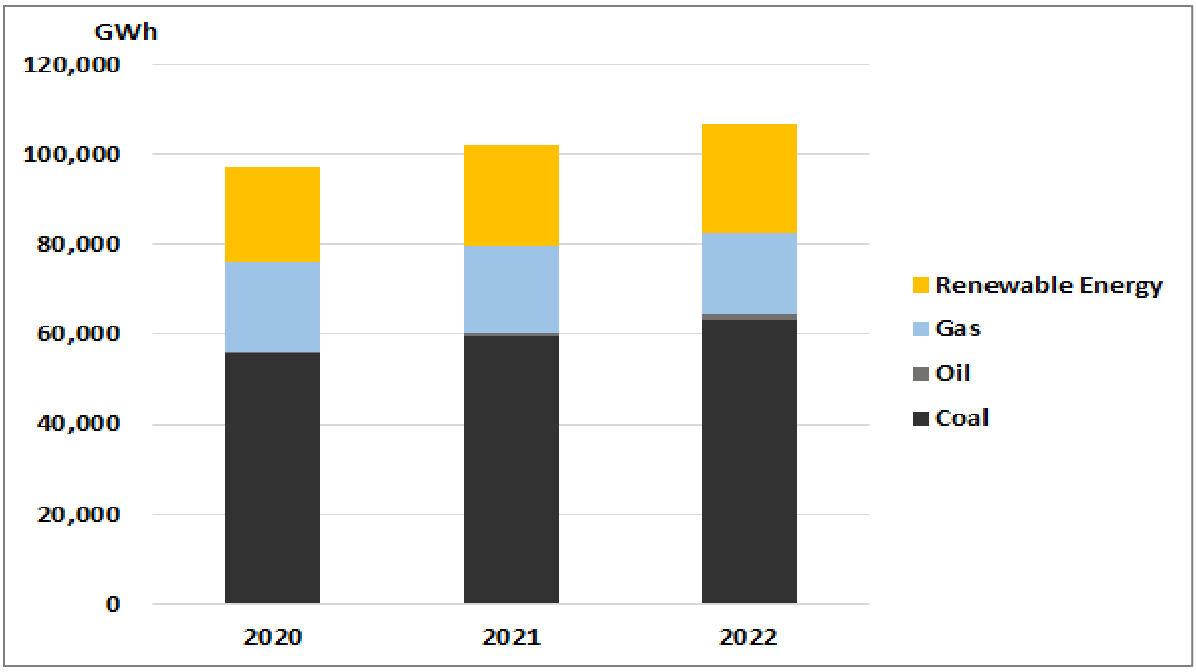
Table 2.4. Primary Energy Consumption in the Philippines

	Mtoe							Shares (%)		
	1990	2000	2010	2021	2030	2040	2050	1990	2021	2050
Total*1	27	39	42	61	83	109	134	100	100	100
Coal	1.3	4.6	7.0	19	22	27	29	4.7	31	22
Oil	9.7	16	14	18	30	44	56	36	30	42
Natural gas	-	0.0	3.1	2.8	6.1	12	21	-	4.6	16
Nuclear	-	-	-	-	-	-	-	-	-	-
Hydro	0.5	0.7	0.7	0.8	1.1	1.2	1.4	2.0	1.3	1.1
Geothermal	4.7	10	8.5	9.2	12	13	13	18	15	9.9
Solar, wind, etc.	-	-	0.0	0.2	1.7	2.3	3.0	-	0.4	2.3
Biomass and waste	10	7.6	8.7	11	10	10	10	39	18	7.6
Hydrogen	-	-	-	-	-	-	-	-	-	-

Mtoe = million tonnes of oil equivalent.
Note: *1 Trade of electricity and heat not shown.
Source: IEEJ (2023).

Output from coal-fired power plants increased by 13% between 2020 and 2022. The rise was driven by a substantial growth in coal imports to the Philippines due to declining domestic growth production. A decline in the domestic Malampaya gas field production contributed to decreased gas-fired power generation. Renewable energy generation also rose by 14% during the same period. Hydropower contributed most of the increase (Figures 2.10 and 2.11).

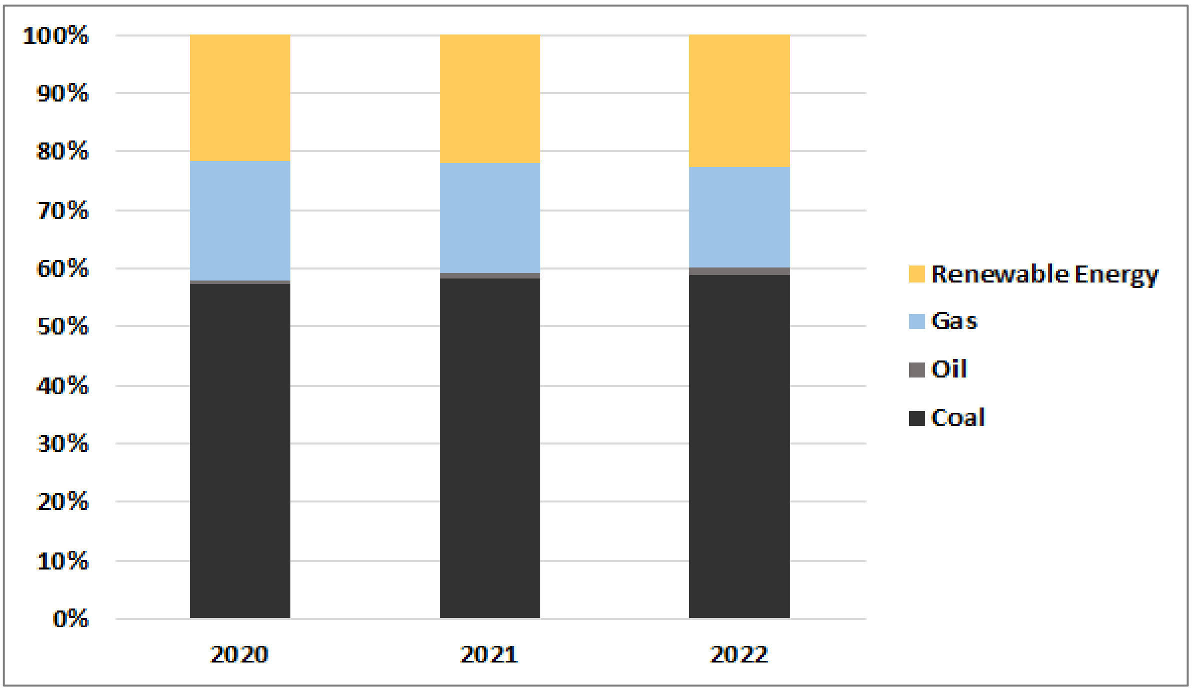
Figure 2.10. Annual Power Generation by Fuel Type, 2020–2022 (GWh)



GWh = gigawatt-hour.
Source: Based on data from Ember.

The government is trying to increase the renewable share in the future whilst sustaining the gas share, particularly in the power sector.

Figure 2.11. Share of Annual Power Generation by Fuel Type, 2020–2022 (%)



Source: Based on data from Ember.

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.

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 USD66 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 2.5. 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.

5. Viet Nam

5.1. Economy and Energy Demand Outlook

The *IEEJ Outlook 2024* forecasts Viet Nam's primary energy consumption to increase by an average of 3.3% per year, based on an assumed economic growth rate (at 2015 prices) of 5.4% annually from 2021 to 2050. The energy mix in 2050 will comprise 36% coal, 30% oil, 14% natural gas, 3.5% nuclear, 4.7% hydro, 6.7% biomass and waste, 4.6% solar, wind, etc. (Table 2.6).

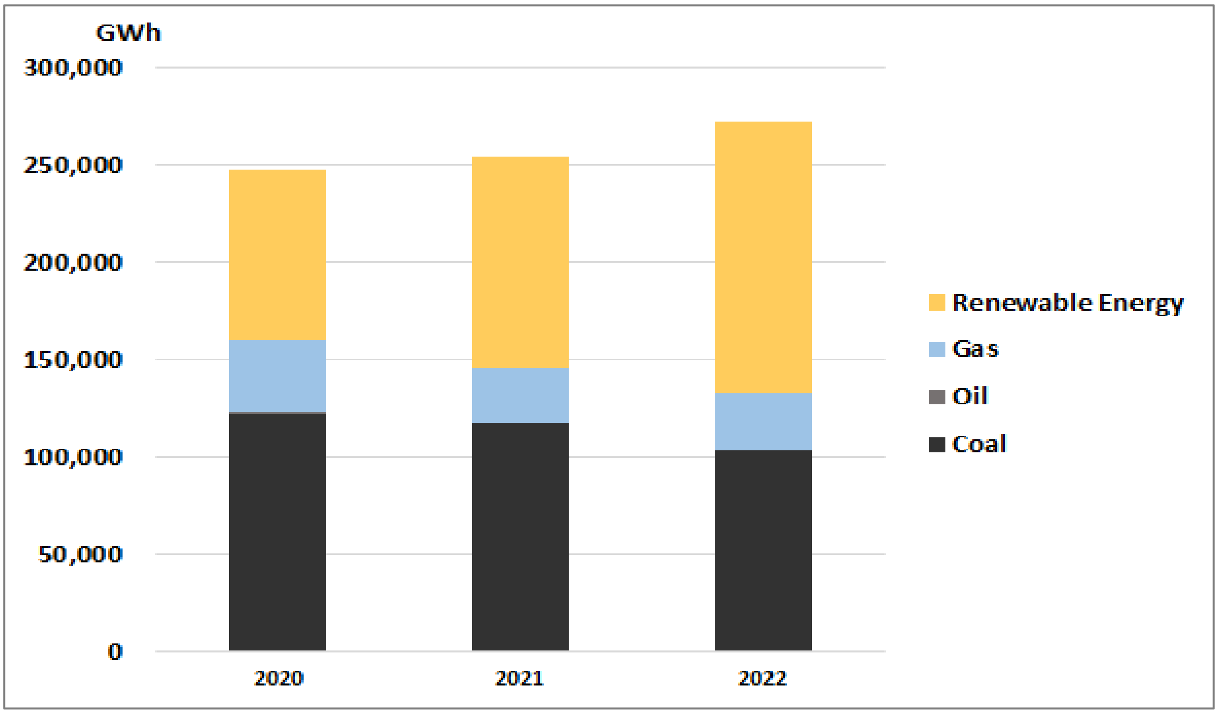
Table 2.6. Primary Energy Consumption in Viet Nam

	Mtoe							Shares (%)		
	1990	2000	2010	2021	2030	2040	2050	1990	2021	2050
Total[*1]	18	29	59	95	152	200	244	100	100	100
Coal	2.2	4.4	15	47	62	78	88	12	49	36
Oil	2.7	7.8	18	23	46	60	73	15	24	30
Natural gas	0.0	1.1	8.1	6.3	16	24	34	0.0	6.6	14
Nuclear	-	-	-	-	-	4.2	8.6	-	-	3.5
Hydro	0.5	1.3	2.4	6.8	9.3	11	12	2.6	7.1	4.7
Geothermal	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	0.0	2.7	7.2	9.4	11	-	2.8	4.6
Biomass and waste	12	14	15	9.7	11	14	16	70	10	6.7
Hydrogen	-	-	-	-	-	-	-	-	-	-

Mtoe = million tonnes of oil equivalent.
Note: *1 Trade of electricity and heat not shown.
Source: IEEJ (2023).

Generation from coal and gas declined by 16% and 20%, respectively, between 2020 and 2022. Due to good water levels in Viet Nam, significant hydropower output increased the overall renewables power in 2022, surpassing the overall thermal power (Figures 2.12 and 2.13).

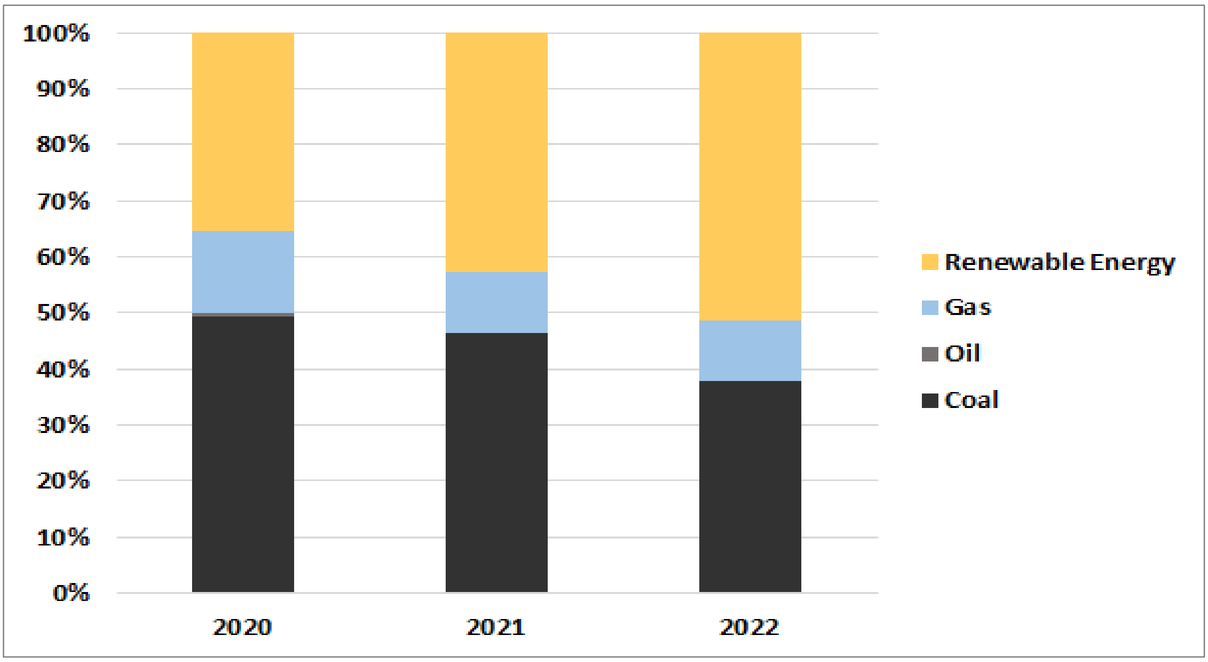
Figure 0.12. Annual Power Generation by Fuel Type, 2020–2022 (GWh)



GWh = gigawatt-hour.
Source: Based on data from Ember.

For the first time, over half of the total power generation in Viet Nam came from renewable energy in 2022 (Figure 2.13).

Figure 2.13. Share of Annual Power Generation by Fuel Type, 2020–2022 (%)

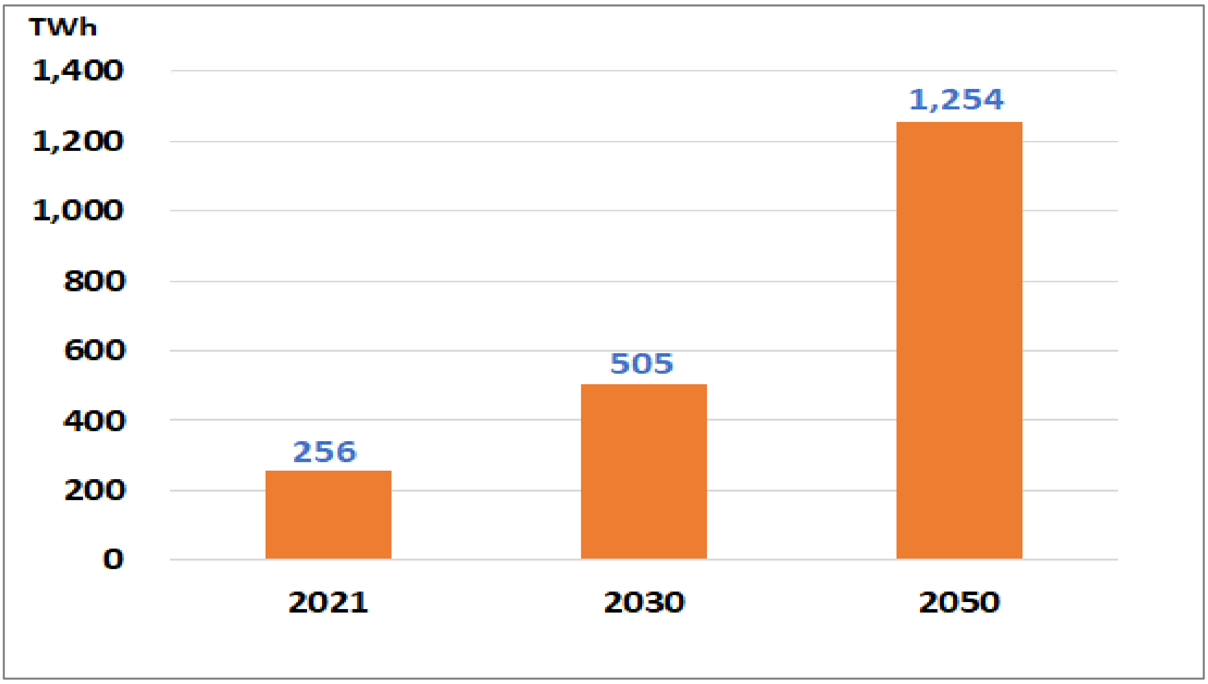


Source: Based on data from Ember.

5.2. PDP8: Viet Nam's New National Power Development Plan

On 15 May 2023, the Government of Viet Nam approved a new National Power Development Plan (PDP8) for 2021–2030, with a vision towards 2050. The PDP8 sets out the roadmap for electricity vision, representing Viet Nam's commitment towards decarbonisation. The PDP8 assumes that the average annual GDP will grow 7% in 2021–2030 (Figure 2.14). The growth rates in 2031–2050 are estimated at 6.5%–7.5% per year. Concerning electricity production, the target by 2025 is to generate 335 terawatt-hour (TWh), about 505 TWh by 2030, and up to 1,254 TWh by 2050. The electricity demand will continue to rise to meet the country's socioeconomic development target.

Figure 2.14. Total Electricity Generation in Viet Nam

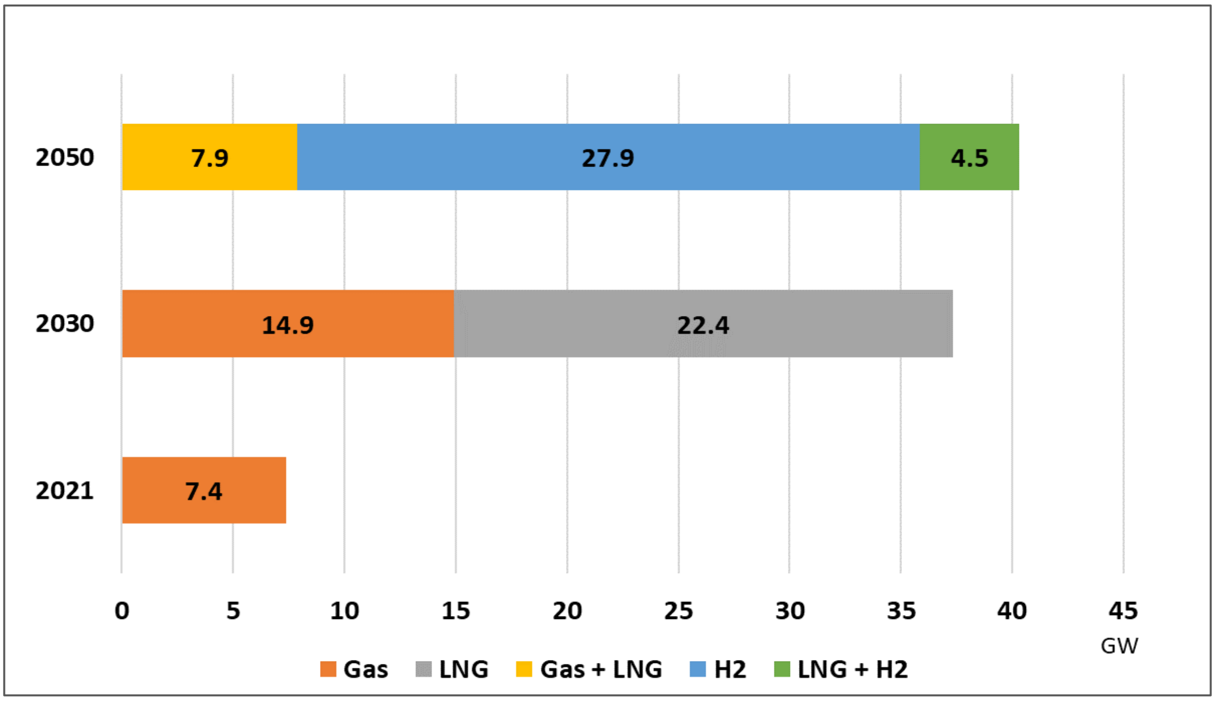


TWh = terawatt-hour.
Source: Based on data from Asia Pacific Energy Research Centre.

According to the latest plan, no new LNG-to-power plants will be developed after 2035, and there will be a transition to using hydrogen by 2050. For gas power, the installed capacity will increase to 37.3 gigawatts (GW) by 2030 from 7.4 GW in 2021. The installed capacity is expected to reach 40.3 GW by 2050, only 3.0 GW up from 2035 (Figure 2.15). The 27.9 GW of gas-fired power capacity will likely switch to hydrogen as input fuel, and 4.5 GW of gas-fired power will be co-firing with hydrogen.

In 2021, the total installed capacity of the coal-fired plant was 25.4 GW, accounting for almost 37% of the overall capacity. Beyond 2030, Viet Nam has decided not to develop any new coal-fired power plant, except for processes planned in the previous PDP, which are currently under construction.

Figure 2.15. Electricity Generated from Gas in Viet Nam



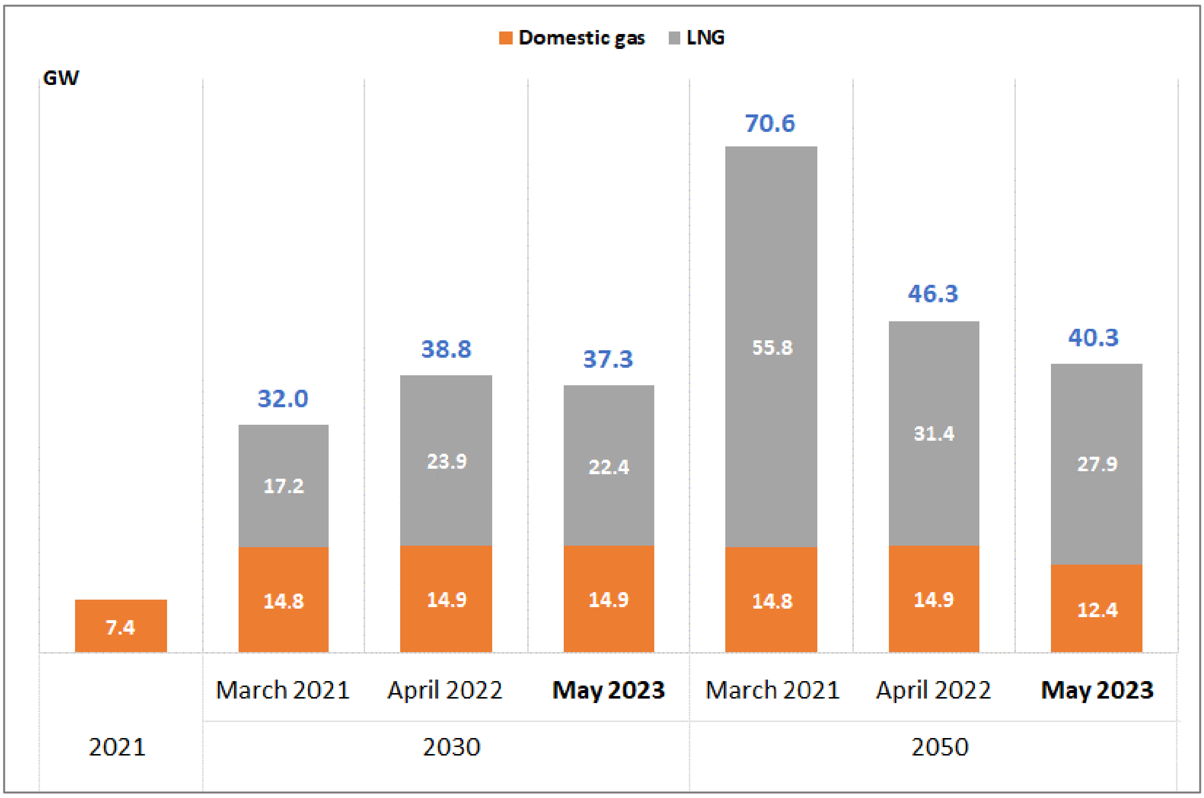
GW = gigawatt, H2 = hydrogen.
Source: Based on data from the Asia Pacific Energy Research Centre.

The extremely high and volatile LNG prices have affected Viet Nam's future LNG usage plan. In the PDP8, there is a major decline in assumed LNG usage volumes as of 2050, between when first assumed in 2021 and when finally approved in 2023 (Figure 2.16).

For two reasons, Viet Nam reduced its gas-fired power capacity in the final draft. First, the volatility of gas prices and the unstable worldwide gas supply chain in 2021 and 2022 were major causes for cutting gas power capacity. Second, although gas power is cleaner than coal power in terms of CO_2 emissions it still emits CO_2. Therefore, the Viet Nam government plans to develop more renewable energy.

The high prices have also delayed LNG power development. For example, the Thị Vải LNG terminal, the first one in Viet Nam was completed in 2022, but the commissioning was postponed until 2023. Another thing, the high prices have made it difficult to finalise the power purchase agreement between investors and the state utility. If the power purchase agreement and infrastructure construction are delayed, the LNG-to-power process will take longer.

Figure 2.16. Assumed Amount of Gas Needed for Power Generation



GW = gigawatt, LNG = liquefied natural gas.
Source: Based on data from the Asia Pacific Energy Research Centre.

5.3. 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 meters 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.

5.4. 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 2024, the terminal received a total of five 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 2.7. 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)	

Receiving Terminal		Capacity (Mtpa)	Storage (kl)	Operation Start	Stakeholders
	(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.

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 the end of 2023, 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 0.795 mt from other countries and 5.1 mt from its own LNG production plants in 2023.

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.

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 km 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 cargos 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

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 (OECD) 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 relationship has been between established LNG producers and established LNG consumers tied with point-to-point sales contracts of multiple decades.

Along with 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 included:

- ✓ 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.

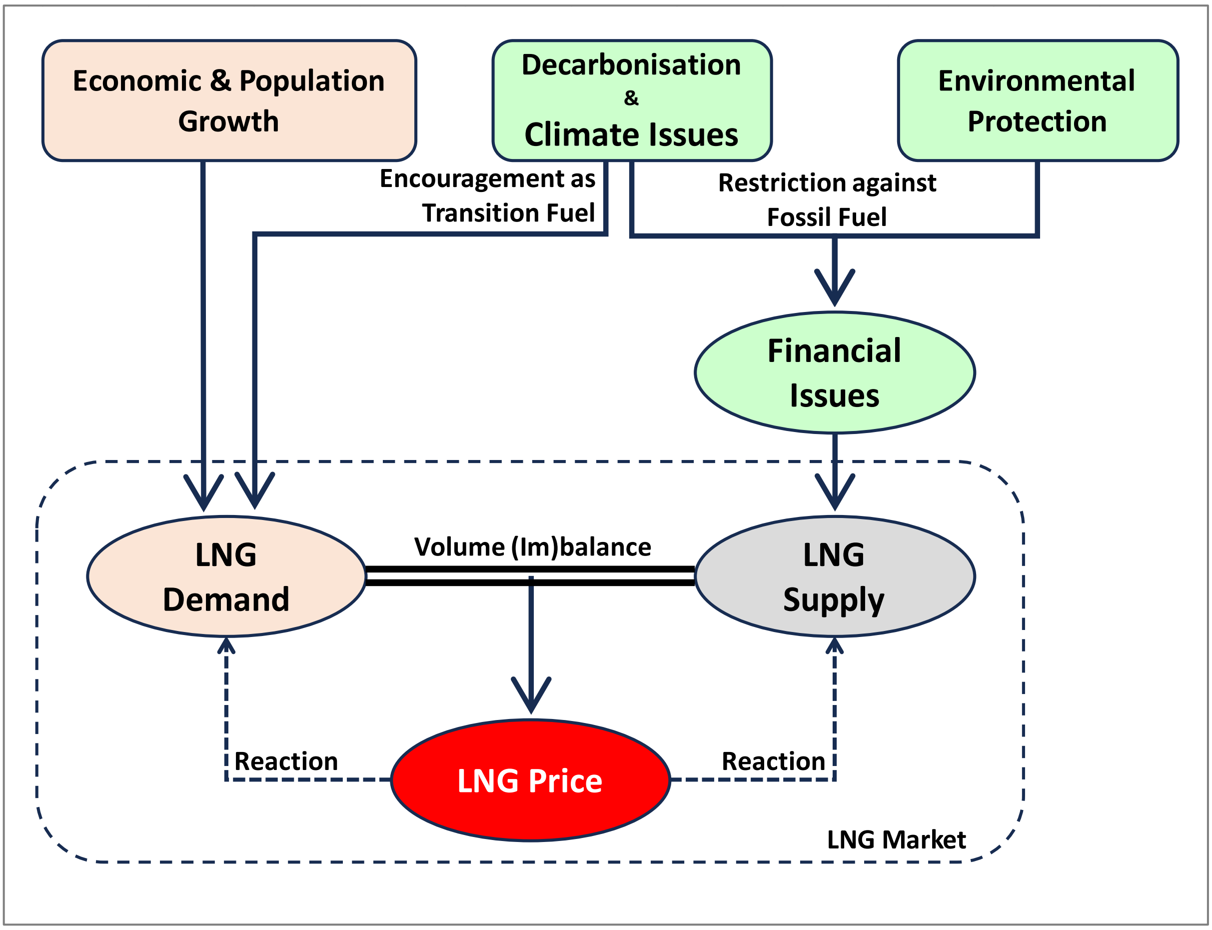
Table 3.1. Examples of Factors in the Global LNG Market Shift

	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-	Transition scenarios changing demand outlooks significantly Demand centres shifting to developing economies Preference for shorter long-term contracts

	Short-term Issues	Long-term Issues
	sensitive markets	
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 3.1. Interrelationships amongst Factors Causing Price Volatility



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

2. Demand Side

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.

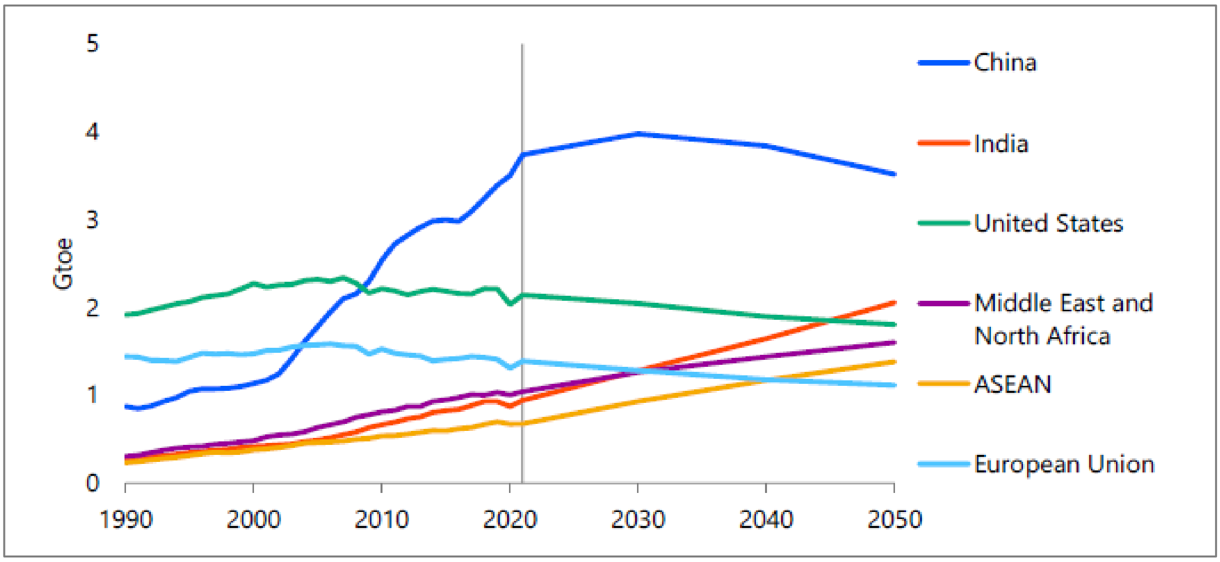
Short-term or sudden changes in circumstances may also significantly impact demand trends. For example, Europe's rapid phase-out of dependence on Russian resources, China's demand recovery caused by ending the zero-COVID policy, and expected or unexpected seasonal demand fluctuations like drought, severe winter, etc. This was clearly shown by the price volatility seen during 2023, as explained in the 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 2024* forecasts primary energy consumption in the ASEAN region to increase at an annual rate of 2.5% between 2021 and 2050 whilst GDP continues to grow at 4.2% per annum (Figure 3.2).

Figure 3.2. Primary Energy Consumption in Selected Countries and Regions



ASEAN = Association of Southeast Asian Nations, Gtoe = gigatonnes of oil equivalent.
Source: IEEJ (2023).

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 2024*, in the ASEAN region, despite an expansion of renewables, the share of natural gas in the energy mix is expected to expand from 20% in 2021 to 25% in 2050 (Table 3.2).

Table 3.2. Primary Energy Consumption Mix (ASEAN)

	Mtoe							Shares (%)		
	1990	2000	2010	2021	2030	2040	2050	1990	2021	2050
Total[*1]	231	378	536	678	930	1 171	1 380	100	100	100
Coal	12	31	85	178	216	271	313	5.3	26	23
Oil	88	153	189	222	298	354	397	38	33	29
Natural gas	30	74	125	135	201	264	339	13	20	25
Nuclear	-	-	-	-	-	9.7	18	-	-	1.3
Hydro	2.3	4.1	6.1	14	18	21	23	1.0	2.0	1.7
Geothermal	6.6	18	25	37	93	129	142	2.9	5.4	10
Solar, wind, etc.	-	-	0.0	4.0	12	21	36	-	0.6	2.6
Biomass and waste	92	97	106	87	88	97	107	40	13	7.8
Hydrogen	-	-	-	-	-	-	-	-	-	-

Mtoe = million tonnes of oil equivalent.
Source: IEEJ (2023).

According to the *IEEJ Outlook 2024*, 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.

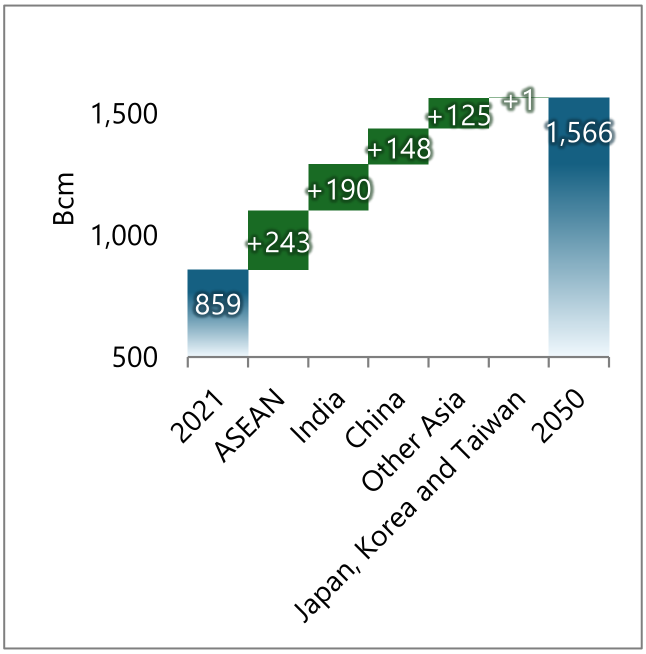
Table 3.3. Natural Gas Production

(Bcm)

	2021	2030	2040	2050	2021-2050	
					Changes	CAGR
World	4 207	4 348	4 778	5 368	1 161	0.8%
North America and Mexico	1 208	1 364	1 409	1 432	224	0.6%
Latin America excluding Mexico	152	164	225	313	162	2.5%
Europe	204	150	130	100	-104	-2.4%
Europe/Central Asia	1 010	848	864	909	-101	-0.4%
Russia	794	618	610	609	-185	-0.9%
Middle East	702	766	871	1 035	333	1.3%
Africa	260	253	368	551	291	2.6%
Asia	517	638	726	825	308	1.6%
China	208	240	248	251	43	0.7%
India	32	45	83	110	78	4.3%
ASEAN	193	216	242	261	68	1.1%
Oceania	155	165	185	204	49	0.9%

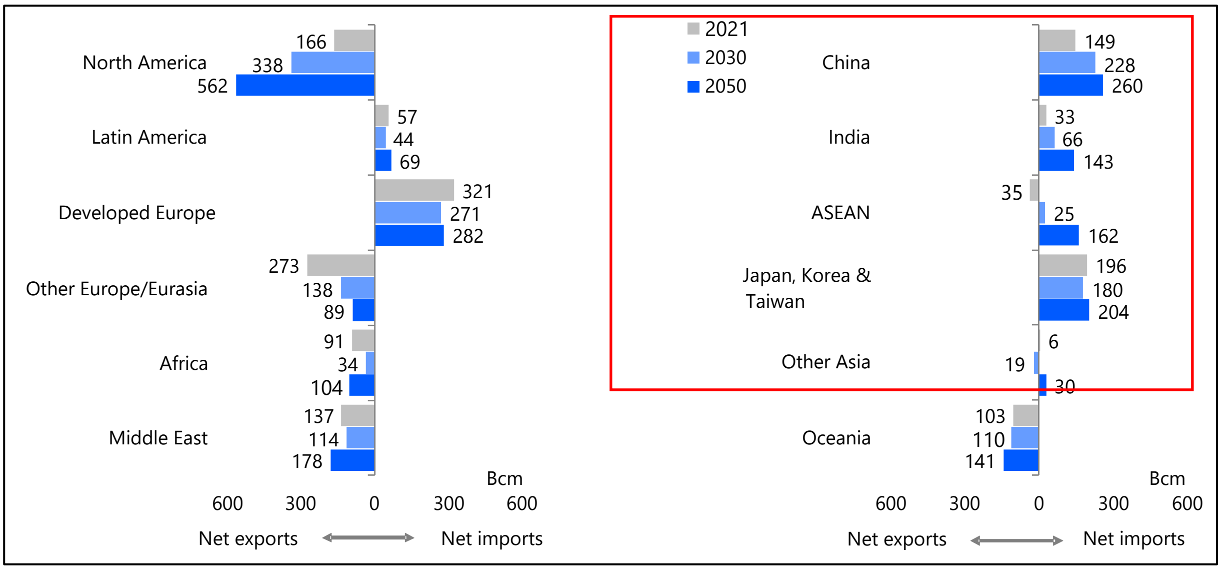
ASEAN = Association of Southeast Asian Nations, Bcm = billion cubic metres, CAGR = compound annual growth rate.
Source: IEEJ (2023).

Figure 3.3. Natural Gas Consumption



ASEAN = Association of Southeast Asian Nations, Bcm = billion cubic metres.
Source: IEEJ (2023).

Figure 3.4. Net Exports and Imports of Natural Gas



ASEAN = Association of Southeast Asian Nations, Bcm = billion cubic metres.
Source: IEEJ (2023).

Recent Situation in LNG Demand

Global LNG imports increased from 372.3 Mt in 2021 to 394.4 Mt in 2022 and to 398.7 Mt in 2023. However, as the export growth has been limited, the IEEJ envisions that the supply–demand balance in the global LNG market will remain tight until 2025.

In 2020, global LNG demand sharply declined because of the COVID-19 pandemic, offsetting the huge production increase in the United States that continued from the previous year and resulted in limited LNG market expansion. The supply side was slow to respond to the demand recovery in late 2020, causing a supply–demand imbalance.

In 2021, China loosened its strict zero-COVID policy, leading to a rapid expansion in LNG trade, which was also driven by the strong demand. But at the same time, planned and unplanned outages or slowdowns of production activities at LNG facilities and upstream gas production sites contributed to supply shortages.

In 2022, LNG transacted volumes expanded by 5%, mostly from product gains in the United States. As Europe needed additional LNG supply to make up for declining Russian gas supply through pipelines, the LNG imports into European countries increased by 46.4 Mt (61.8% year-on-year). Europe's share in the global market reached 30.8% in 2022 from 20.2% in 2021, which was covered mainly by the LNG production growth from the United States. Due to significantly higher spot LNG prices, Asian countries decreased LNG imports from 272.5 Mt in 2021 to 254.9 Mt in 2022. China decreased its LNG imports by 15.5 Mt, and South Asian countries (India, Bangladesh, and Pakistan) decreased their imports by 5.9 Mt.

In 2023, global LNG trade fluctuated less than 1 year earlier, except for a relatively large decrease in Japan's LNG import. Europe continued increasing LNG imports to replace the lost Russian pipeline gas supply. However, the pace of growth was moderated by higher inventories of underground gas storage in the region and a significant reduction in gas consumption because of a milder winter and structural demand destruction. ASEAN importers increased LNG imports significantly, with the Philippines and Viet Nam joining as new LNG importing markets. China returned to growth of LNG imports and regained the position of the largest importer of LNG in the year, although it is still below the record import in 2021.

In the first half of 2024, Europe decreased imports of LNG dramatically compared to the first half of the previous year. The relative price stability made it easier for China, India, Southeast Asia, and Pakistan and Bangladesh to increase LNG imports. On the export side, there seems to be few changes for the main exporting countries except for Egypt, which is suffering from gas shortages due to lower domestic gas production and domestic gas demand increase (Figure 3.5).

Figure 3.5. LNG Imports and Exports in the First Half of the Year

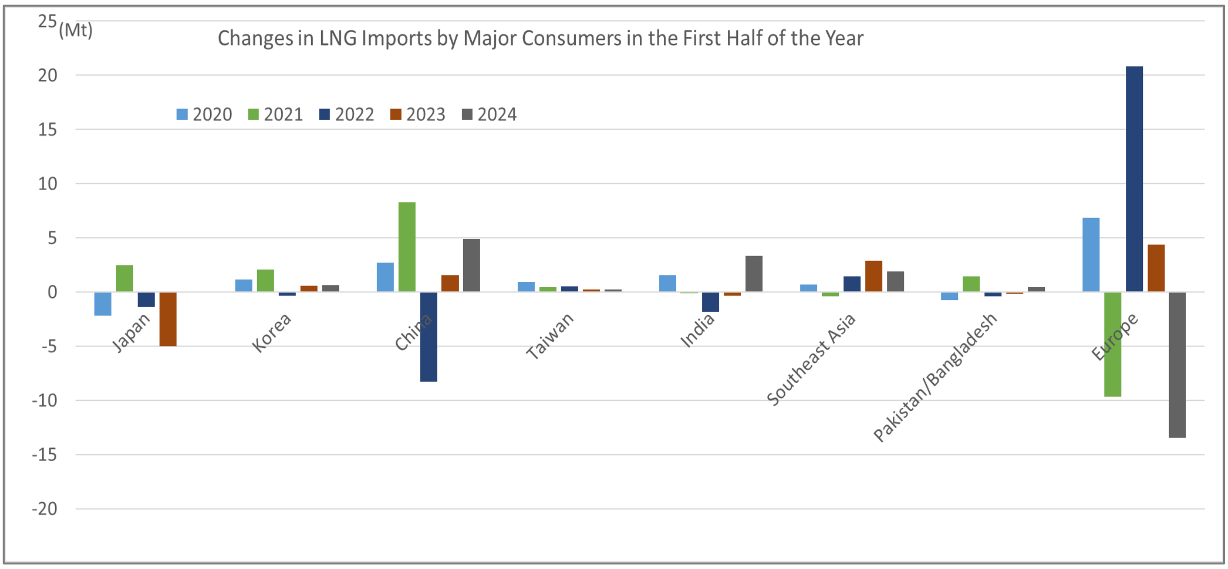
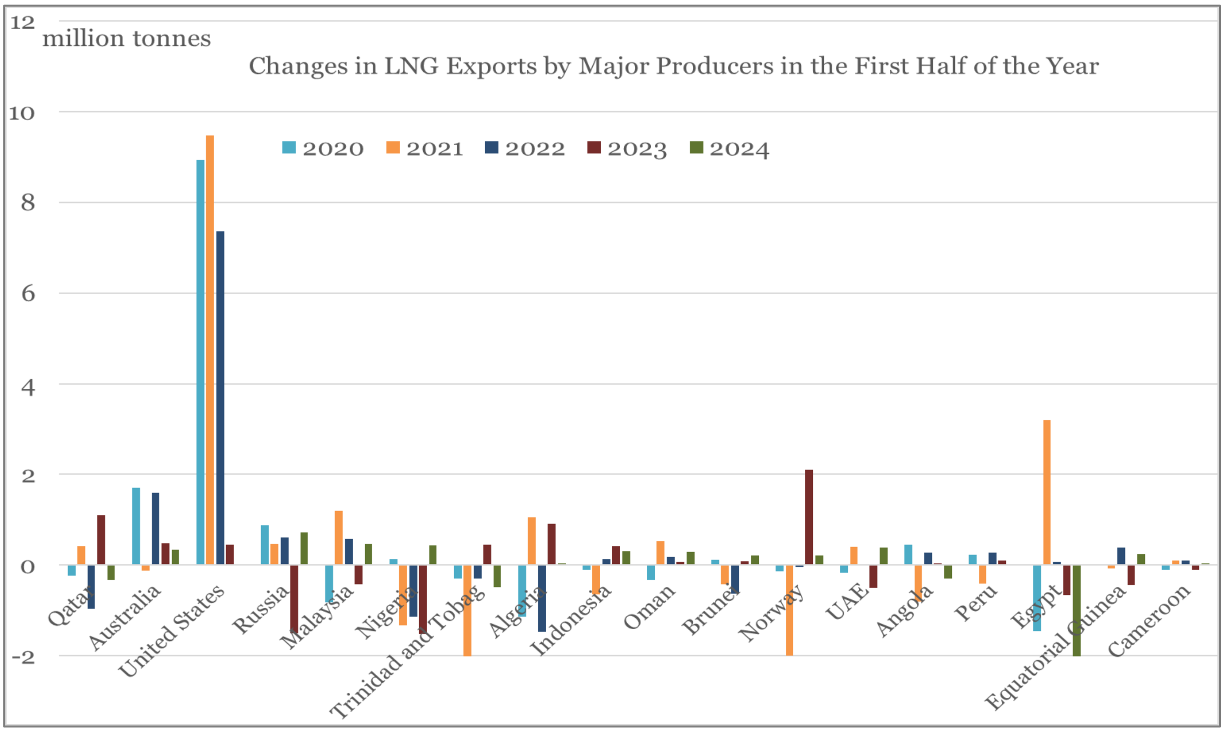


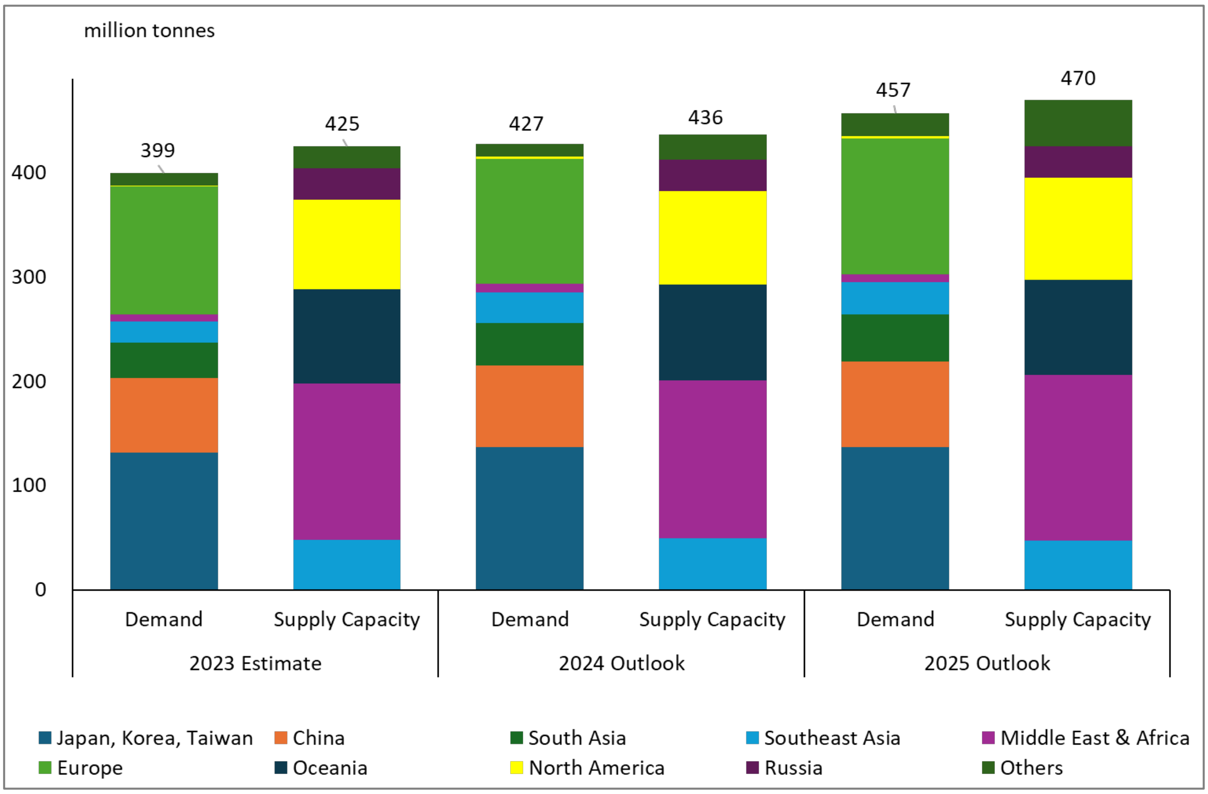
Figure 3.5. *Continued*



LNG = liquefied natural gas, Mt = million tonnes, LNG = liquefied natural gas, Mt = million tonnes, UAE = United Arab Emirates.
Source: Based on Cedigaz and trade statistics of various countries.

The supply–demand balance in the global LNG market is expected to remain tight until 2025. (Figure 3.6) 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 3.6. Short-term LNG Trade Outlook



LNG = liquefied natural gas.
Source: IEEJ (2023b).

2.2. European Union: A Powerful Buyer of LNG since 2022

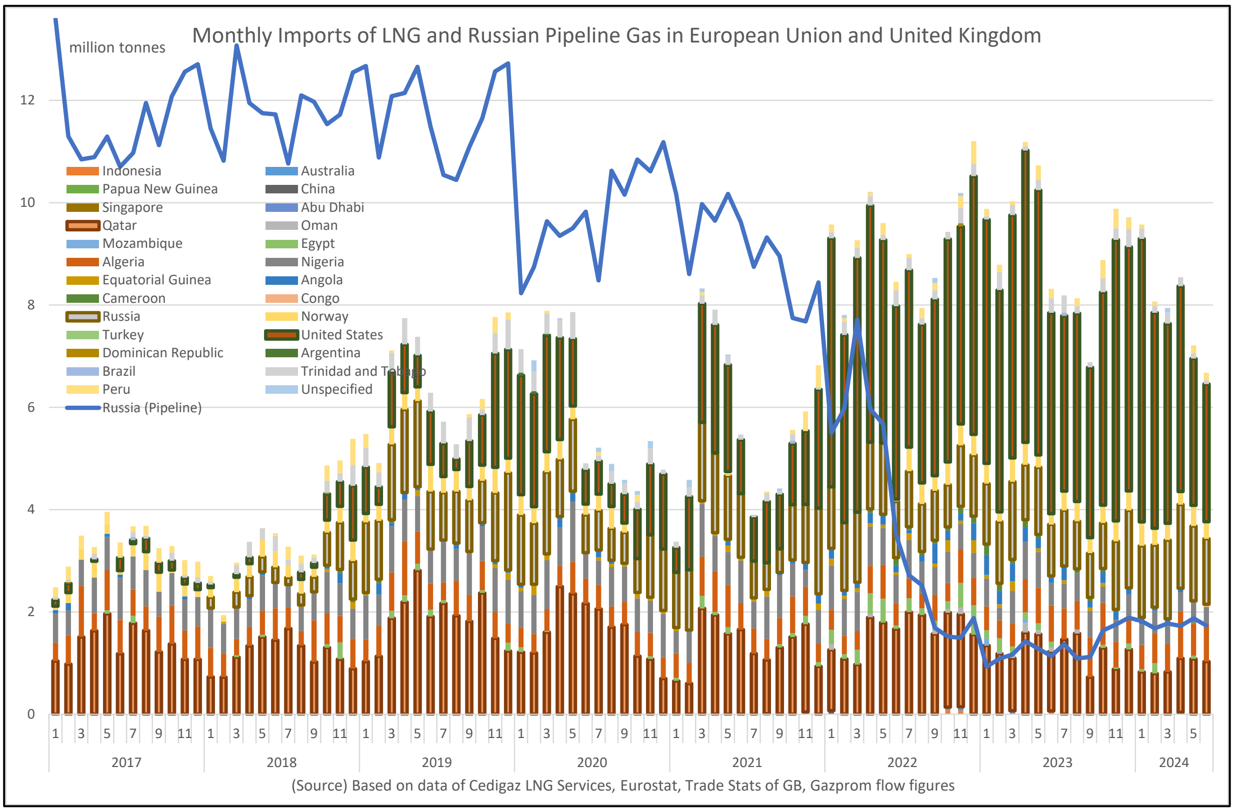
Since the Russian invasion of Ukraine in February 2022, Europe has emerged as an enormous LNG buyer with strong purchasing power. The purchasing power of Europe is expected to stay strong for at least several years, but may be phased out by around 2050 with the progress of its decarbonisation ambitions.

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.

Figure 3.7. Monthly Imports of LNG and Russian Pipeline Gas to Europe

(Europe = EU + UK)



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

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 14 Mt each of Russian LNG in 2022 and 2023, slightly increasing from 2021.

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.

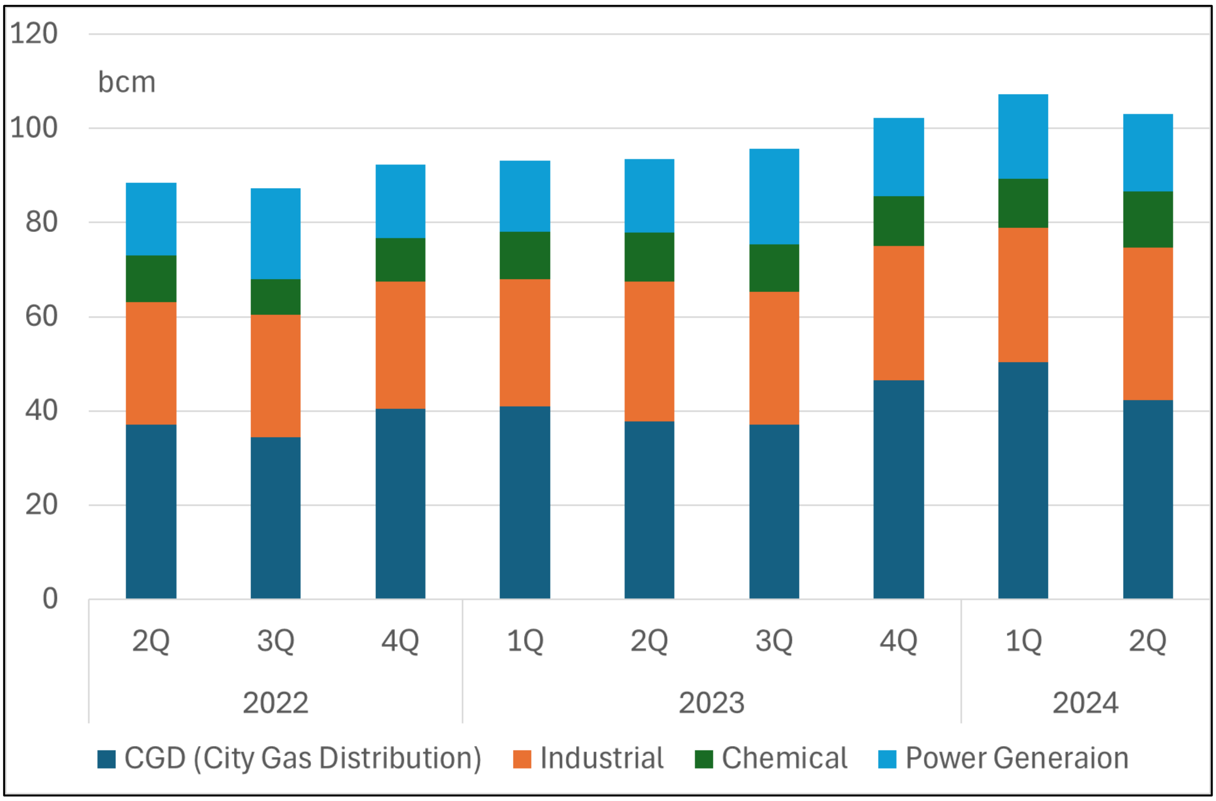
China's demand trend can easily impact the global LNG market. In 2021, China surpassed Japan in LNG imports, becoming the world's largest LNG importer for the first time. But in 2022, the COVID-19 pandemic and high LNG prices significantly reduced its LNG imports, with Japan returning to the world's 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 industrial 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 an important factor. 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. 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 timing of additional introduction of 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.

China's natural gas consumption increased by 13% year-on-year during the first half of 2024. Whilst the share of power generation sector in natural gas demand was relatively low at 16% as of the first half of 2024 and did not change compared with the previous year, the demand volume itself increased from 31 Bcm to 34 Bcm year-on-year during the same period (Figure 3.8).

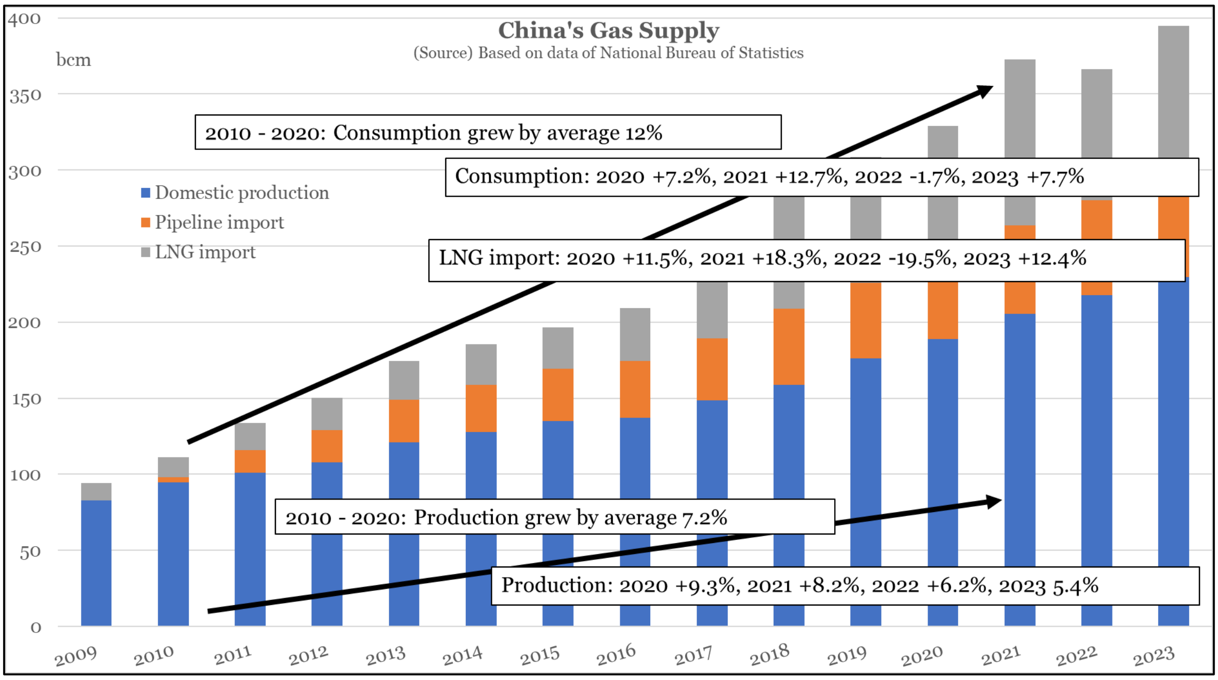
Figure 3.8. China's Natural Gas Demand by Sector



Source: Institute of Energy Economics, Japan analysis based on data of the National Statistics Bureau of China.

Between 2010 and 2020, the share of natural gas doubled, and consumption increased more than three times. The net imports have accounted for more than 40% of the total gas consumption since 2018 (Figure 3.9).

Figure 3.9. Demand and Breakdown of Supply Source in China, 2009–2023



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 (Table 3.4).

Table 3.4. Long-term Contracts Made by Chinese Companies (2022–1H 2024)

Date	Project	Counterpart	Volume (Mtpa)	Duration (year)	Delivery	Price	Export Country
2022/03/29	Lake Charles	ENN	1.8	20	FOB	Henry Hub	US
2022/03/29	Lake Charles	ENN	0.9	20	FOB	Henry Hub	US
2022/04/01	Mexico Pacific Limited	Guangzhou	2.0	20	NA	NA	Mexico

Date	Project	Counterpart	Volume (Mtpa)	Duration (year)	Delivery	Price	Export Country
2022/04/06	NextDecade Rio Grande	ENN	1.5	20	FOB	Henry Hub	US
2022/06/05	Lake Charles	China Gas	0.7	25	FOB	Henry Hub	US
2022/07/05	NextDecade Rio Grande	China Gas	1.0	20	FOB	Henry Hub	US
2022/07/06	NextDecade Rio Grande	Guangdong Energy	1.0	20	DES	Henry Hub	US
2022/07/20	Cheniere Corpus Christi Stage III	PetroChina	0.9	25	FOB	Henry Hub	US
2022/07/20	Cheniere Corpus Christi future trains	PetroChina	0.9	25	FOB	Henry Hub	US
2022/11/21	QatarEnergy	Sinopec	4.0	27	DES	NA	Qatar
2022/11/24	bp	Shenzhen Energy	NA	NA	NA	NA	Portfolio
2022/12/27	NextDecade Rio Grande	ENN	0.5	20	FOB	Henry Hub	US
2023/02/07	Oman LNG	UNIPEC	1.0	4	FOB	NA	Oman
2023/02/23	VG Plaquemines	China Gas	1.0	20	FOB	NA	US
2023/02/23	VG CP2	China Gas	1.0	20	FOB	NA	US
2023/06/20	QatarEnergy	CNPC	4.0	27	DES	NA	Qatar
2023/06/26	Cheniere Sabine Pass Expansion	ENN	1.8	20	FOB	NA	US
2023/07/05	Mexico Pacific LNG	Zhejiang Energy	1	20	FOB	NA	Mexico
2023/09/07	ADNOC LNG	PetroChina	NA	NA	NA	NA	Abu Dhabi
2023/11/02	Cheniere	Foran Energy	0.9	15	FOB	NA	US
2023/11/02	QatarEnergy	Sinopec	3	27	DES	NA	Qatar

DES = delivery ex-ship, FOB = free on board, Mtpa = million tonnes per annum, NA = not available, US = United States.
Source: Analysis by Institute of Energy Economics, Japan.

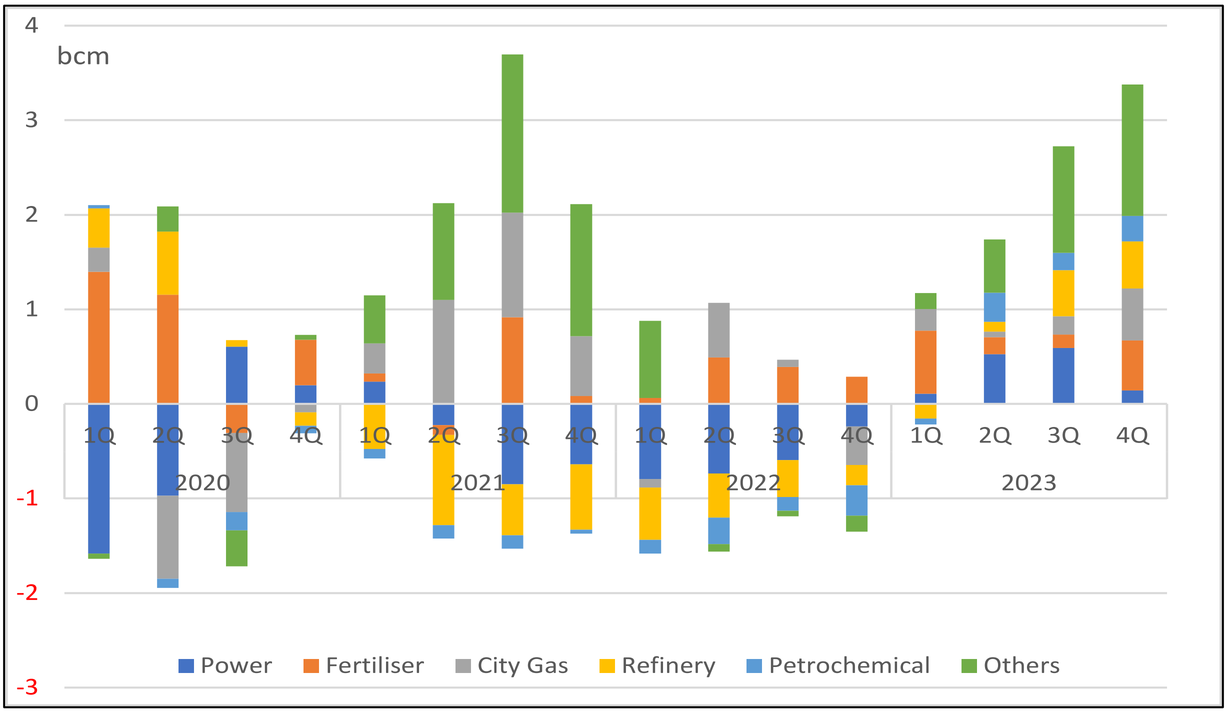
2.4. India and South Asia

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 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, Oil and Natural Gas Corporation, declined, private sector gas production increased by 25% or 2.1 Bcm. In 2023, 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. In 2024, such trend continues. (Figure 3.10).

Figure 3.10. India's Gas Demand by Sector (year-on-year changes)



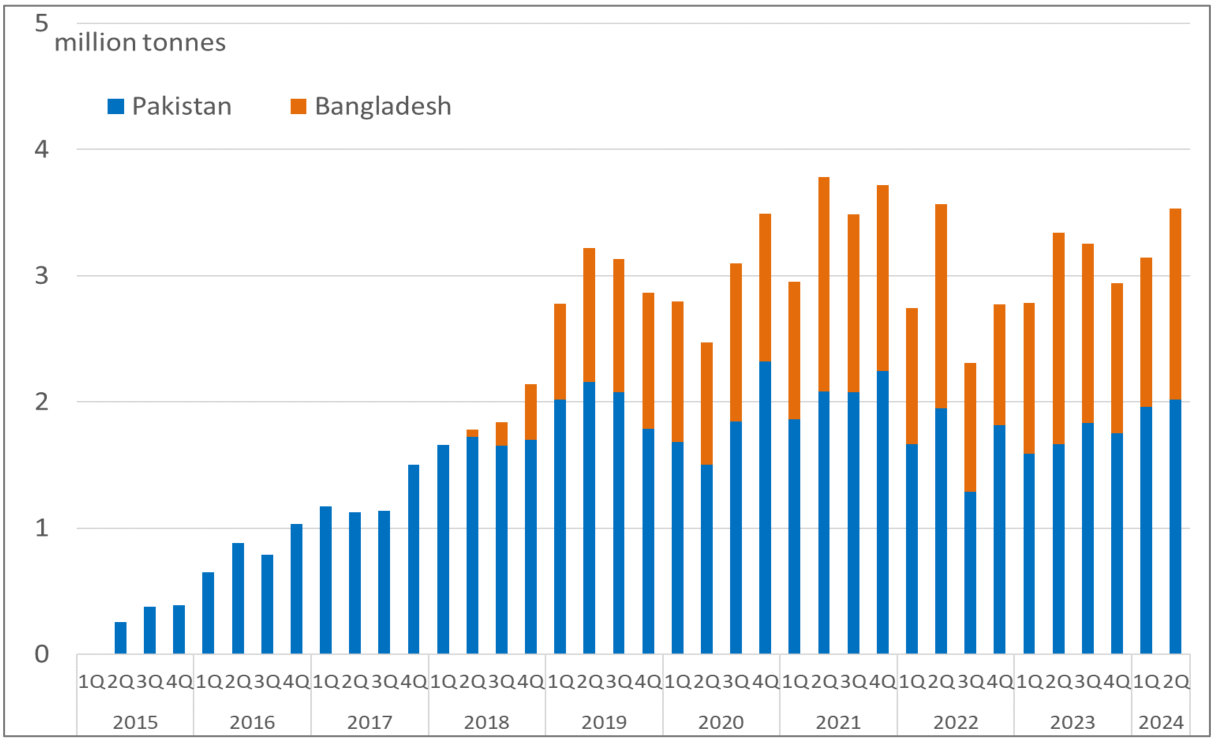
Bcm = billion cubic metre.
Note: Y axis represents year-on-year changes of quarterly gas demand by sector with the plus numbers indicating increases and the negative numbers indicating decreases.
Source: Institute of Energy Economics, Japan analysis of data from the Ministry of Petroleum and Natural 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 3.11). 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.

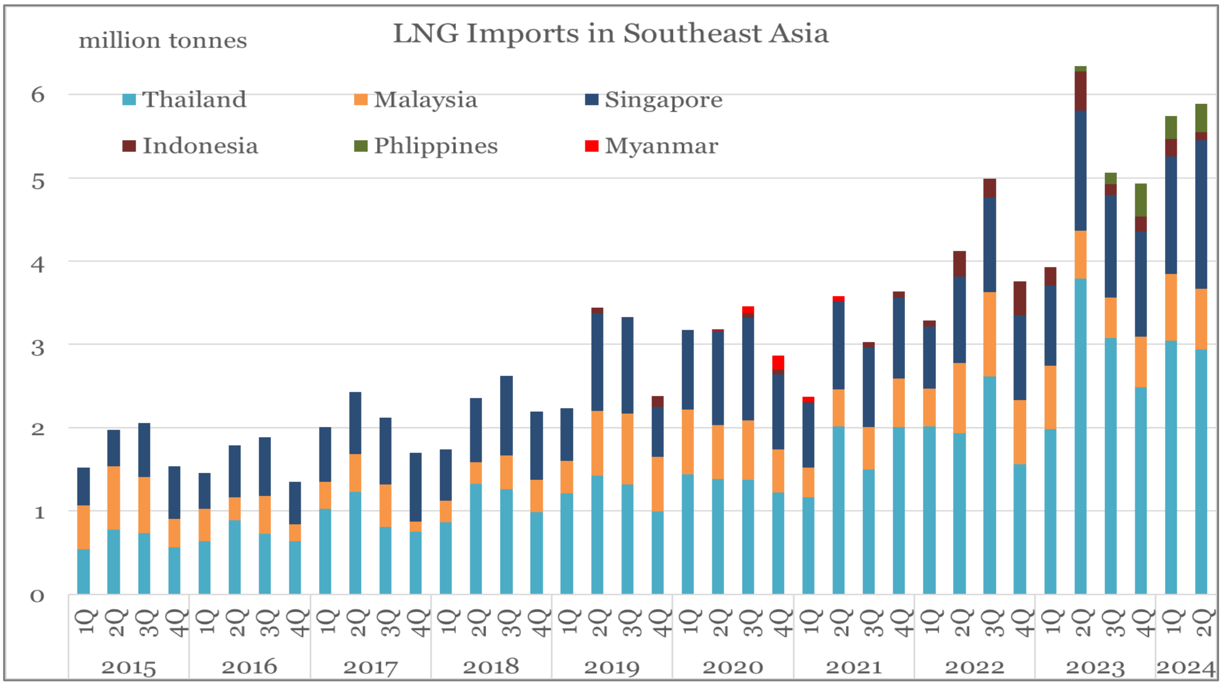
If a country has a lower credit rating, it is difficult for an LNG importer in such a country to secure a long-term LNG purchase contract and secure LNG cargo in the spot market.

Figure 3.11. LNG Imports by Bangladesh and Pakistan



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

Figure 3.12. LNG Imports by Southeast Asian Countries



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

3. Supply Side

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 (FID).

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* (Q2 2024), 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.

3.2. 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. 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 3.13 is a brief recap of the factors.

Middle East

- ✓ Qatar
  - ➢ Significant expansion (North Field East and North Field South) projects are expected from 2025 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 Turkey.

Asia–Pacific

- ✓ Australia
  - ➢ Several LNG-related legislative reforms entered enforced 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 is under construction, with the first LNG cargo shipment expected in 2025.

- ✓ United States
  - ➢ Freeport LNG has returned to full operation, making the United States the world's largest LNG exporter in 2023.
  - ➢ More long-term offtake commitments are expected to facilitate investment decisions.
  - ➢ The government promotes investment towards electrifying gas fields and LNG facilities.
  - ➢ The government announced the pause of LNG export permits to non-free trade agreement (FTA) countries in January 2024.
- ✓ Mexico
  - ➢ New Fortress Energy achieved first LNG production from its Altamira floating LNG (FLNG) facility in July 2024. (New Fortress Energy, 2024).

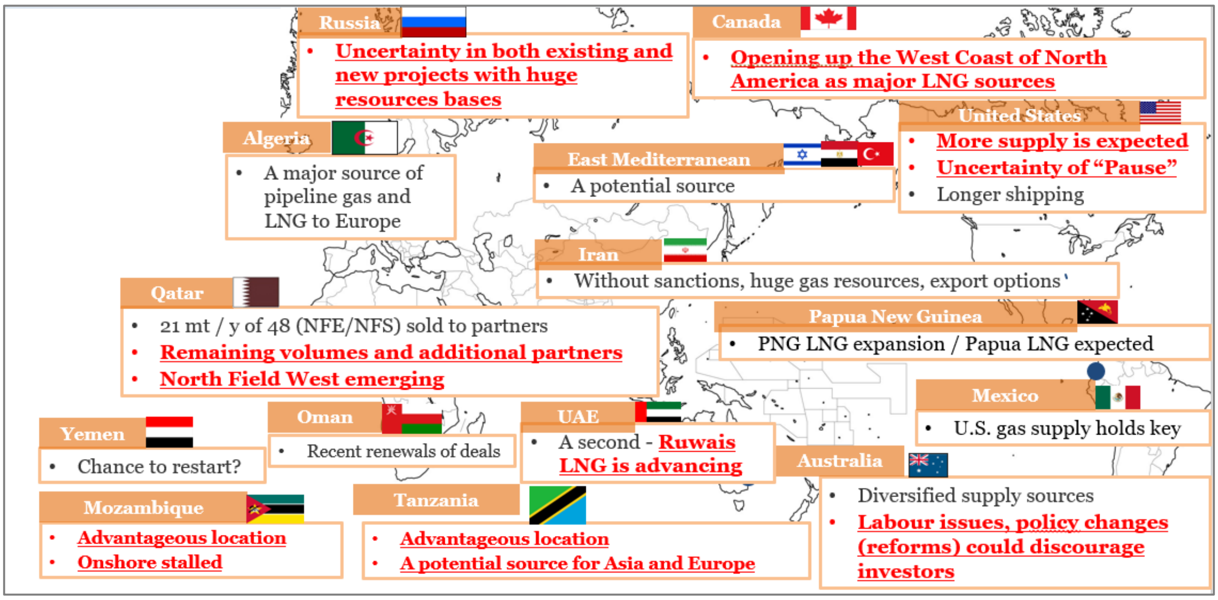
Europe

- ✓ 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 with a FID potentially in 2025.
- ✓ 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 3.13. Examples of Factors to be Considered on the Supply Side



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

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 3.13 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.

✓ Indonesia

- ➢ Tangguh – the construction of LNG facility Train 3 was delayed due to COVID-19 by more than a 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.

4. Evolving Ways of LNG Transactions

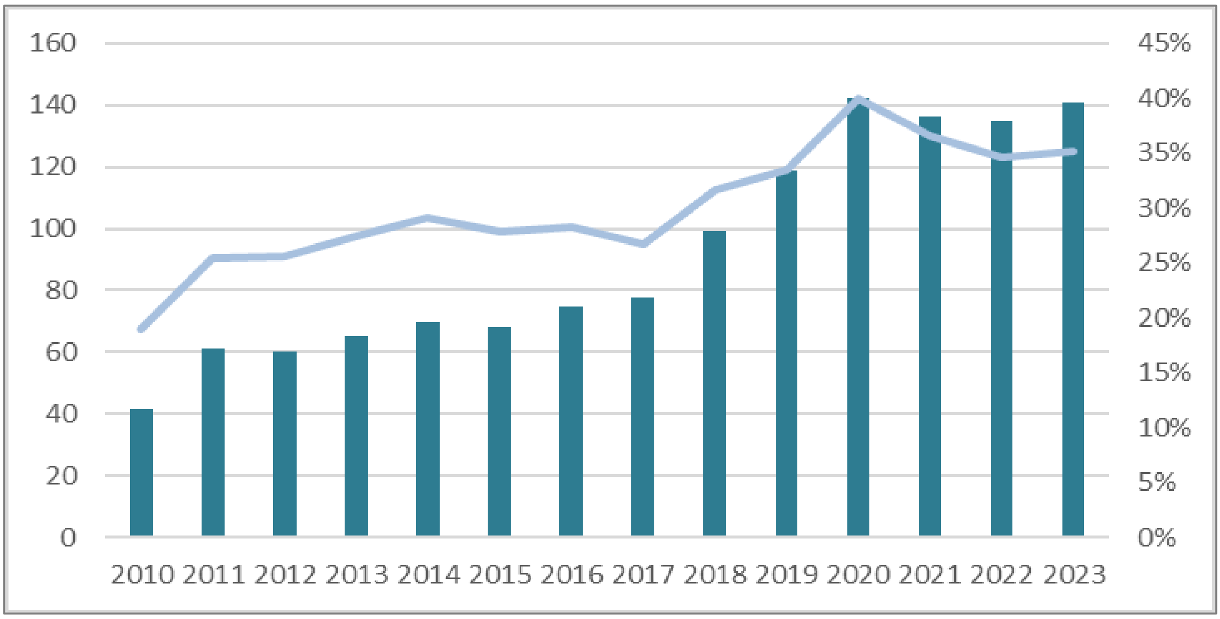
4.1. Increasing Spot and Short-term Transactions

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 401.2 Mt in 2023, with 154.7 Mt (39%) of which was imported on a spot or short-term basis, and 35% was imported under purely spot transactions (delivered within 3 months after agreements) (Figure 3.14).

Figure 3.14. Share of Spot and Short-term vs Total LNG Trade (Mtpa/%)



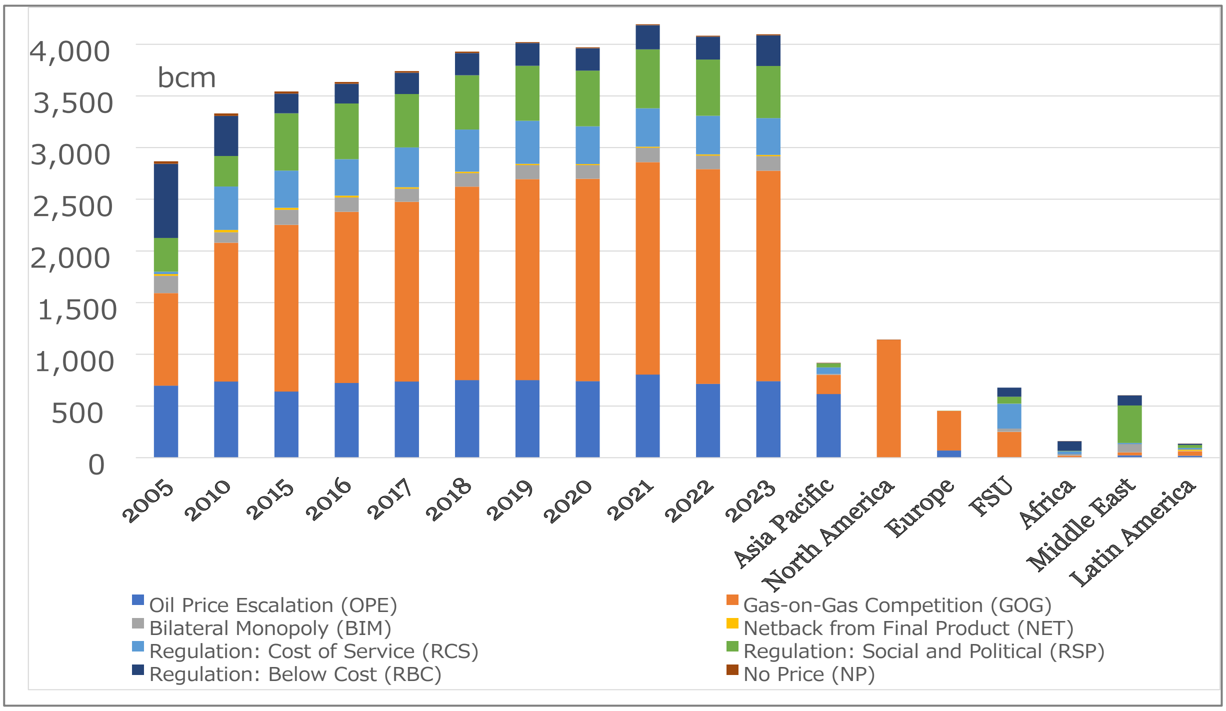
LNG = liquefied natural gas, Mtpa = million tonnes per annum.
(*) The line shows the share of spot and short-term LNG, whilst the bars show the volume of spot and short-term LNG trade.
Source: GIIGNL (2024).

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 3.15).

Figure 3.15. Gas Pricing Mechanism



Bcm = billion cubic metres.
Source: Based on IGU (2024).

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

The industry needs to fill the gap between buyers' preference for flexibility and shorter duration of contracts and sellers' requirement 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
Prominent Potential Solution to Energy Trilemma

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 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 United States 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 United States 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, LNG exports from the United States reached 84.5 million tonnes (on delivered basis in importing economies), the highest ever annual exported volume from one LNG exporting country, which accounts for more than one-fifth of all LNG exports globally. By the time, all current LNG projects in the United States are complete later this decade, LNG exporting capacity from the United States will be roughly 180 million tonnes per year, a little more than double the current levels. The United States administration has authorised exports of 350 million tonnes per year, four times the current LNG production and export levels in the country, although there has been concern over a potential prolonged halt of export authorisation.

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

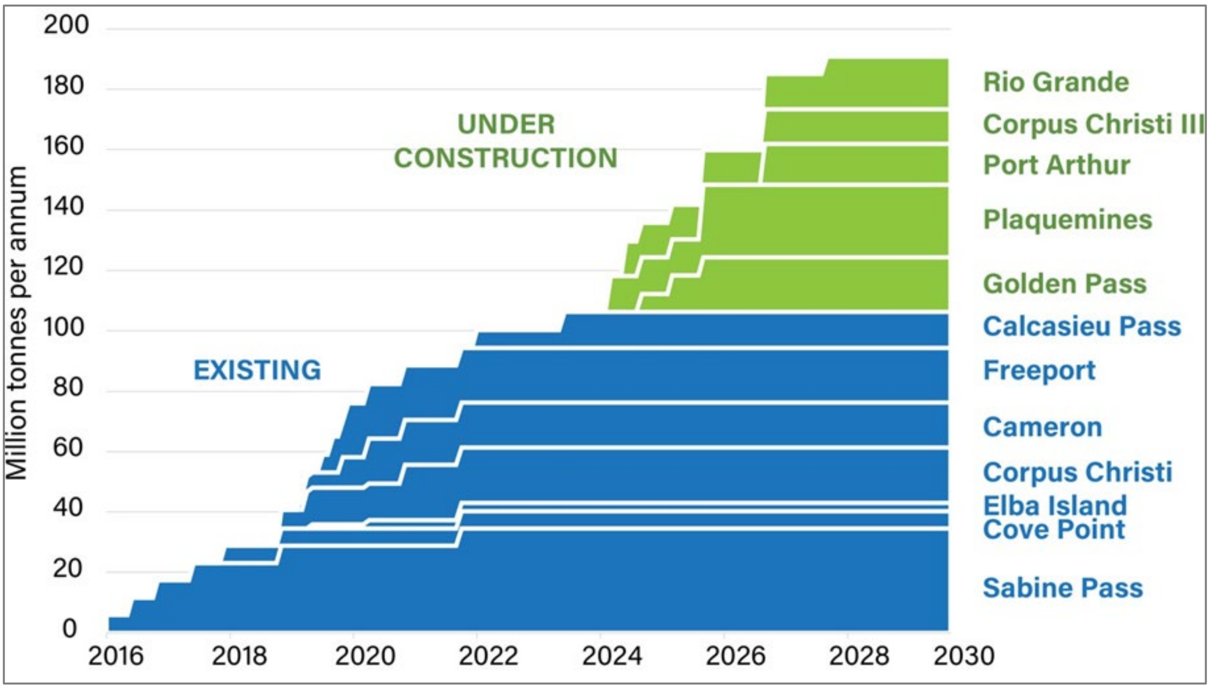
2. Price of LNG from the United States

Estimated costs and deemed FOB prices of LNG from the United States are more reasonable than the recent spot prices and the long-term contracts many Asian countries have made (Figure 1.1). According to one company executive, 'we can put natural gas on the doorstep of Europe for a cost of USD13/MBtu: USD4 for production, USD2 for transportation through pipelines to the facility, USD4 for liquefaction, and USD3 for cargoes to destination.'

3. Volume of LNG from the United States

According to data from the Energy Information Administration (EIA), the LNG export infrastructure capacity is projected to double by 2030. The peak nameplate capacity currently stands at 106 million tonnes per annum (Mtpa), but the terminals under construction could add another 120 Mtpa by the end of this decade. To meet long-term global LNG demand, the United States needs to ramp up its infrastructure further by eliminating political obstacles to new LNG terminals (Figure 4.1).

Figure 4.1. Existing and Under Construction LNG Export Terminals in the United States



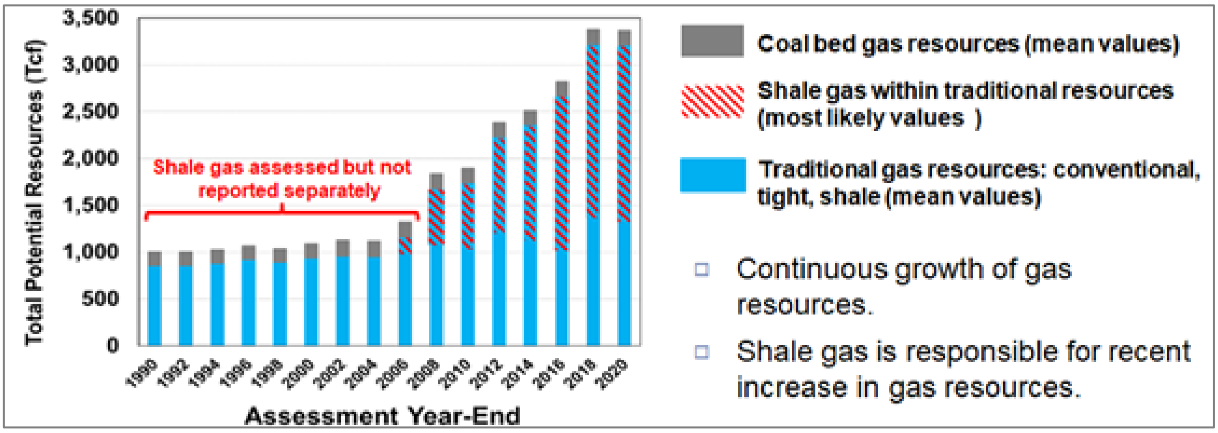
LNG = liquefied natural gas.
Source: Energy Policy Research Foundation Inc, analysis from Energy Information Administration data.

The United States' resource base does not limit the capacity to expand natural gas and LNG exports. Future natural gas supplies from the United States 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. There is now comprehensive documentation that the resource in the country can produce sustained and sizeable natural gas increases for the United States and world markets.

The Potential Gas Committee (PGC) at the Colorado School of Mines in Boulder, Colorado, provides highly authoritative and accurate natural gas resource base assessments (PGC, 2020). Data up to 2020 show that the United States possesses a total mean technically recoverable resource base of 3,368 trillion cubic feet (Tcf) as of year-end 2020. PGC surveys, undertaken every 2 years, confirm that the United States has an abundance of natural gas. The PGC's year-end 2020 assessment concludes that the United States has 3,212 Tcf of gas potentially recoverable from traditional reservoirs (conventional, tight sands, carbonates, and shales) and 157 Tcf in coal bed gas reservoirs.

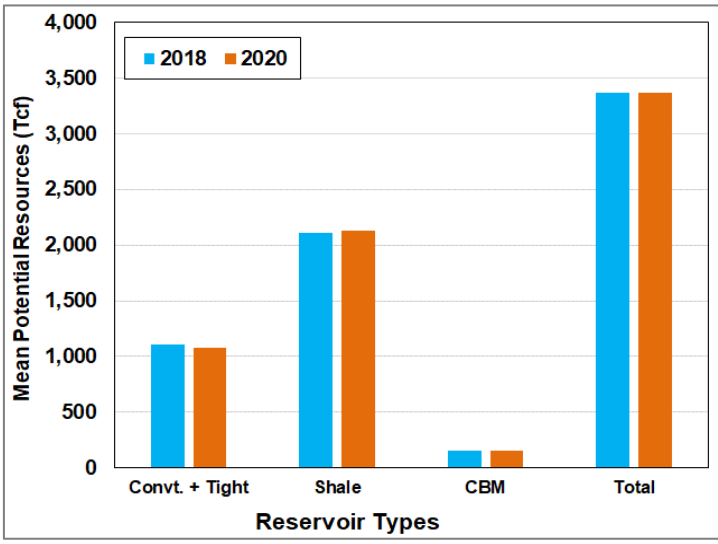
The EIA estimates of proved gas reserves confirm the PGC estimates and examines resource categories that are additional to the resources assessed by the PGC. When the PGC's assessments of technically recoverable resources are combined with the EIA's latest determination of proved reserves in regions not evaluated by the PGC, the United States future natural gas supply stands at a record 3,863 Tcf. Although precise estimates of the potential volume of natural gas recovery from these reserves are difficult to determine, the important conclusion is that periodic assessments of United States resources since 1990 document a long-term trend that the resource base remains massive (Figures 4.2 and 4.3).

Figure 4.2. Estimates of Recoverable United States' Natural Gas Resources, 1990–2020



Tcf = trillion cubic feet.
Source: Potential Gas Committee (2020).

Figure 4.3. Estimates of Recoverable United States' Natural Gas by Category, 2018–2020

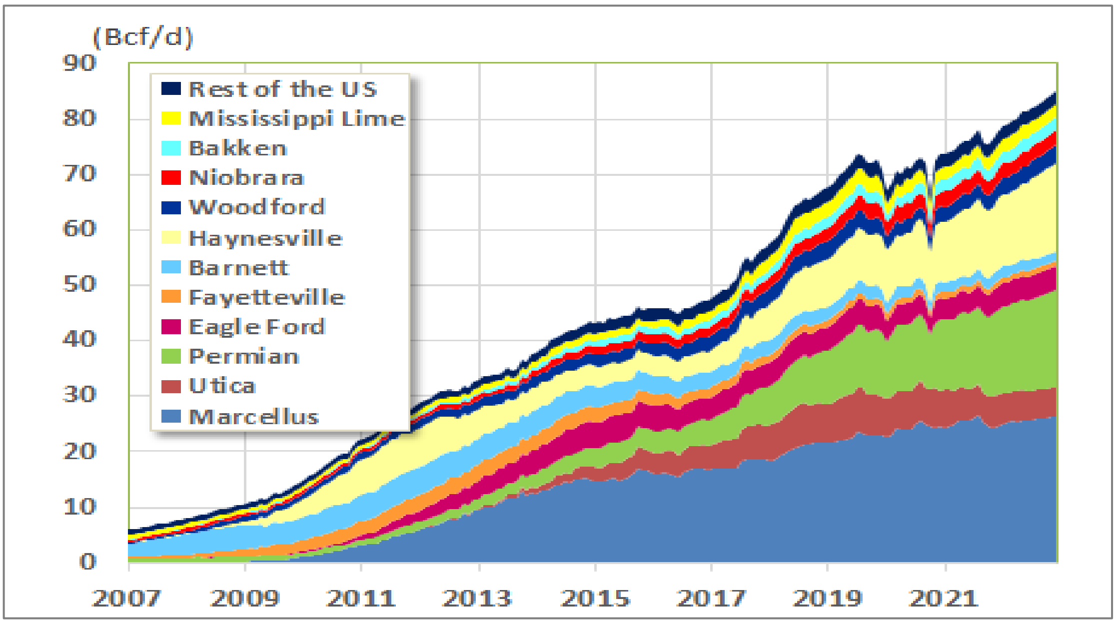


- Small decrease in gas resources in conventional and tight sand/carbonate reservoirs (29 Tcf or 2.6%).
- Small increase in shale gas resources (23 Tcf or 1%).
- No change in coal bed gas (CBM) resources.
- Total mean potential gas resources decrease of 6 Tcf or 0.2%.

Tcf = trillion cubic feet.
Source: Potential Gas Committee (2020).

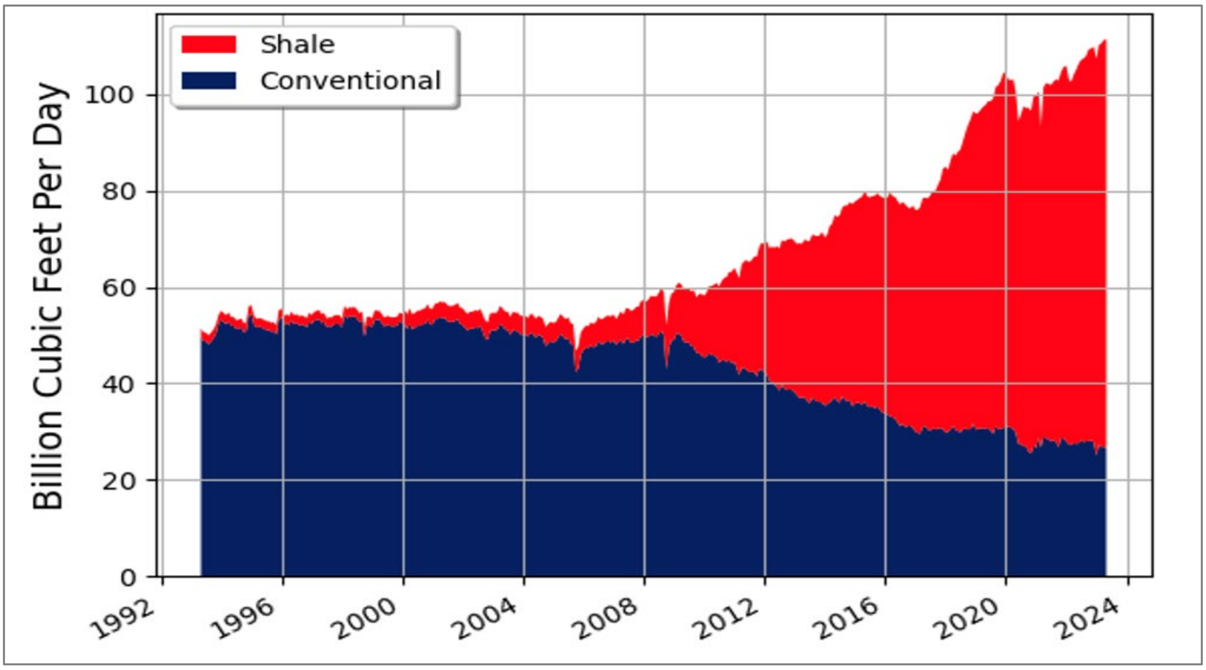
As shown in Figure 4.4, US producers, in response to the massive resource base, have demonstrated the capacity to continue expanding natural gas production, especially from shale dry gas reserves. Figure 4.5 shows that almost all new natural gas production is from shale resources.

Figure 4.4. Monthly United States' Shale Dry Gas Production, 2007–2023



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

Figure 4.5. Most Additions to United States' Supply Were Sourced from Shale Resources



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

4. Current and Historical LNG Export Trend

4.1. Outline of LNG Exports from the United States

The United States 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. When combining all flows and making appropriate adjustments for cross-border transfers, the United States is approaching net natural gas exports of 14 billion cubic feet per day (Bcf/d).

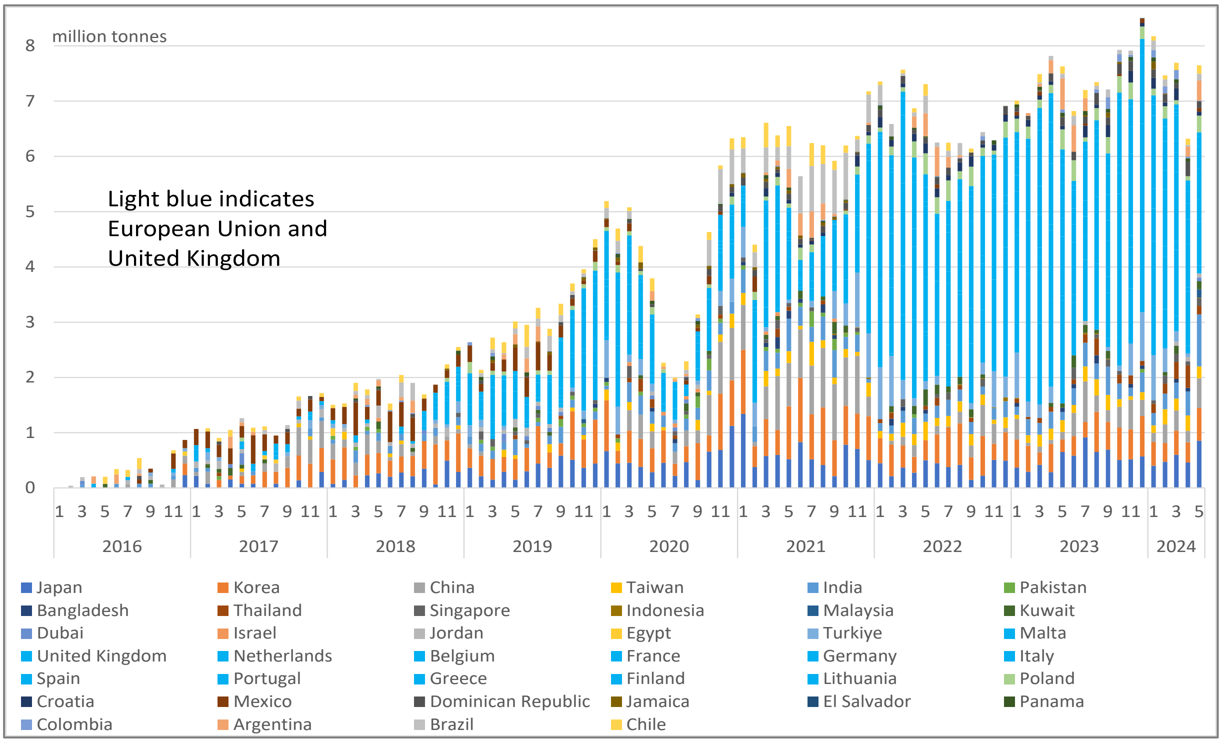
Table 4.1. United States' Natural Gas Production, Imports, and Exports, 2020–2023

Category	CY2020	CY 2021	CY 2022	CY 2023	CY 2024P	CY 2025P
Dry Gas Production(Bcf/d)	92.4	94.6	99.6	103.8	103.5	105.2
LNG Imports (Bcf/d)	0.1	0.1	0.1	0.1	0.1	0.1
LNG Exports (Bcf/d)	6.5	9.8	10.6	11.9	12.2	14.3
Pipeline Gas Imports (Bcf/d)	6.8	7.6	8.2	8.0	7.7	7.5
Pipeline Gas Exports (Bcf/d)	7.9	8.5	8.3	9.0	9.3	9.6
Other (Bcf/d)	-0.9	-0.3	-1.3	-0.4	-0.7	0.3
Total Supply (Bcf/d)	84.0	83.7	87.7	90.6	89.0	89.1
Total Demand (Bcf/d)	83.5	84.0	88.5	89.1	89.4	89.2
Working Gas Storage Change (Bcf)	**179**	**-83**	**-281**	**549**	**-131**	**-60**

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.

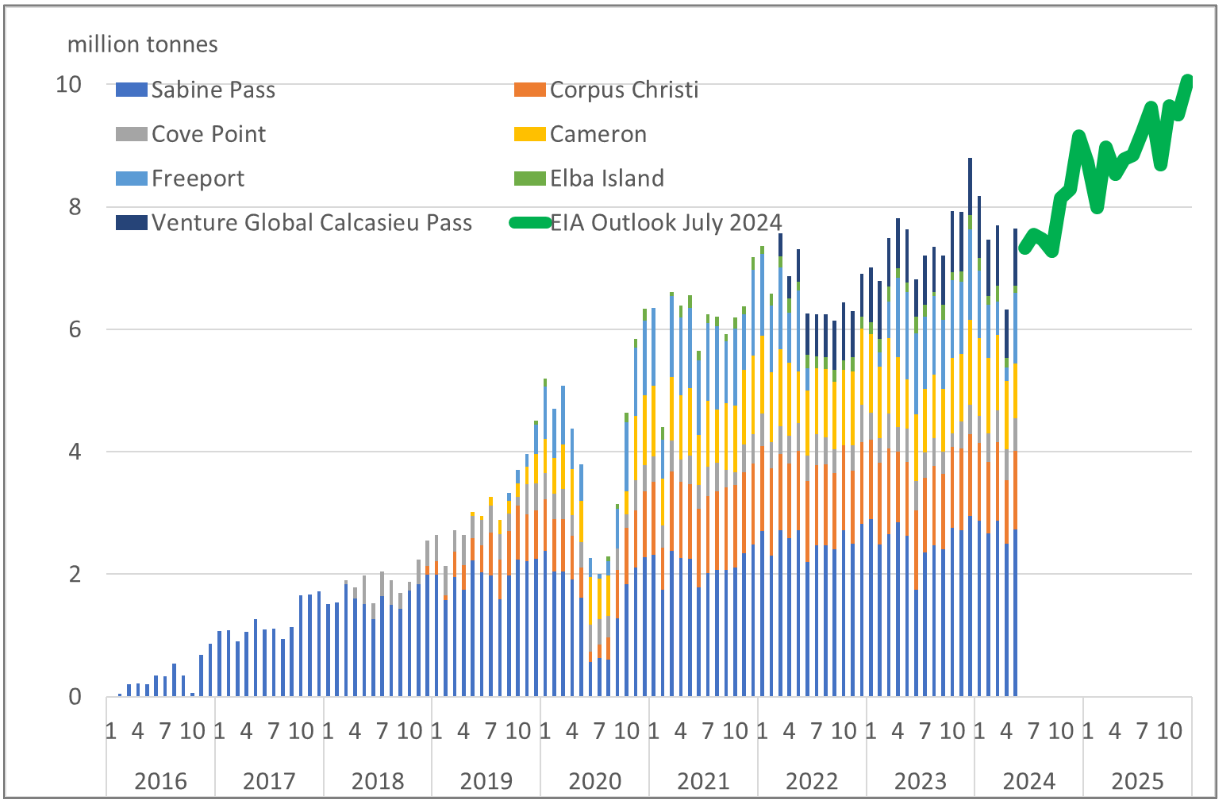
Regarding LNG exports, two-thirds of LNG from the United States was directed to Europe in 2023, reflecting lower transportation costs and rising values due to the Russian invasion of Ukraine and the loss of Russian supplies to the European continent. Figure 4.6 shows increasing volumes, growing to above 60 million tonnes into the main distribution hubs in Europe. As shown in Figure 4.7, volumes to Asia fell dramatically in 2023, reaching approximately 45 million tonnes briefly in 2021 but falling to nearly 15 million tonnes in 2023 as the war in Ukraine has continued over the last year.

Figure 4.6. LNG Exports from the United States by Destination, 2016–2024



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

Figure 4.7. LNG Exports from the United States by Project

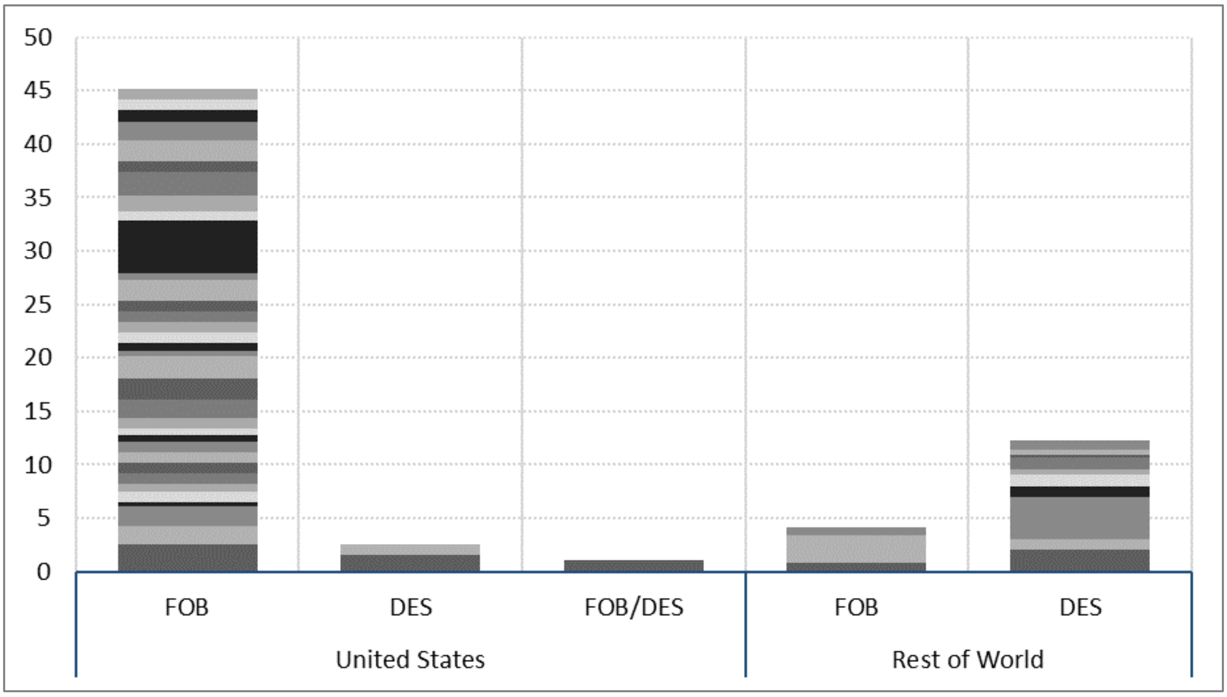


EIA = Energy Information Administration, LNG = liquefied natural gas.
Source: Compiled based on data from the US Department of Energy and Energy Information Administration.

4.2. Destination-Free Clause

Most LNG contracts originated from the United States offer a destination-free clause (FOB), allowing importers to reroute or resell LNG purchased from the United States. This is an improvement over the traditionally more dominant delivered ex-ship (DES) clause. With more LNG project promotors in the United States 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 United States. Of the 39 contracts, only two have DES clauses. In contrast, only three of the remaining 16 contracts by other countries had FOB clauses (Figure 4.8).

Figure 4.8. 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.

5. The 'Pause' Halting LNG Export Authorisation Process

5.1. Outline of the Pause

Three liquefaction projects totalling 38 million tonnes per year of capacity reached an final investment decision (FID) in 2023 in the United States, whilst several additional projects have postponed their decisions.

The US administration announced in late January 2024 a pause of review processes of applications of licences to export LNG to those countries that do not have free trade agreements (FTA) with the United States and a plan of renewed studies on economic and environmental impacts of LNG exports. In the ASEAN region, only Singapore is an FTA country regarding trade relationships with the United States. This pause is not viewed by many government officials in the United States as a constraint on LNG exports since so many projects have already received permission to proceed but have not yet achieved financing to proceed. However, this is an inadequate process for ensuring more exports of LNG from the United States. The pause creates uncertainties that affect both the daily operations of United States companies as well as the image of the United States as a reliable supplier, which may undermine the energy security cooperation the United States has built with allies over the past decade.

The direct impact of the pause affects 30 million tonnes out of 150 million tonnes per year of LNG sales deals globally announced in 2022 and 2023. The 30 million tonnes of sales from those LNG projects have not yet granted export authorisation to non-FTA countries, yet are directly affected by the pause. The pause is already directly impacting on LNG procurement activities by Japanese and European companies. If the pause is translated into corresponding delays of LNG export deliveries, the relevant buyers will need to revise their procurement plans.

The proponents of the pause have also been claiming a limited impact due to the exclusion of FTA trading partners from the pause. However, the share of FTA destinations in LNG exports from the United States has decreased consistently over the years, and they now account for only approximately 10% of total LNG exports from the United States. The non-FTA countries, which include some of the biggest US allies, promise the greatest incremental LNG demand. Thus, restricting new infrastructure or exports to non-FTA destinations effectively halts any future incremental LNG supplies beyond those already approved. Consequently, the pause has a significant impact.

5.2. Practical Impacts of the Pause

The US administration says '48 bcf/d (365 Mtpa) has been authorised.' The administration has emphasised that the pause will not affect the already approved non-FTA LNG exports. The assumption is that even with the pause, the LNG export capacity will continue expanding in the next 5 years or so, enabling the LNG production from the United States to meet the requirements of the international market demands, including allies of the United States. But 22 bcf/d out of this 48 bcf/d has not reached a FID yet and there is no assurance of realisation of this 22 bcf/d.

There is misalignment between commercial and regulatory progress: whilst 22 bcf/d has authorisations there is insufficient commercial progress, and 30 Mtpa of reserved volumes that is mentioned in the preceding subsection have not secured non-FTA authorisations. Although the authority may not be expected to say anything directly on commercial issues, something can be made on the mismatch between regulatory and commercial progresses.

Whilst license extensions for already authorised, capacity are said to be unaffected, the initial instances after the pause should be closely monitored. In fact, a project has already submitted extension request, and its outcome is being closely watched.

It is uncertain when the authorisation review process will resume, even though the officials have said within months rather than years.

A public comment period is expected following the studies, but the exact timing is unknown. It would be open to the international parties or individuals. Interested parties – current and future LNG offtakers – should start preparing their comments immediately (or today), taking into account of possible outcomes of the studies, to make their comments meaningful and considered. There have already been some advancements of LNG projects elsewhere and in the United States after the pause was introduced.

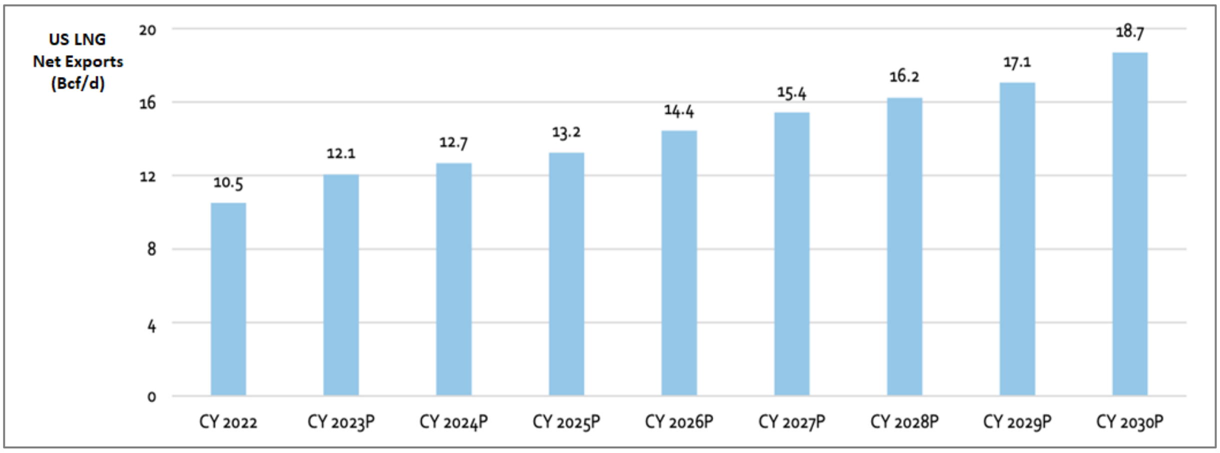
Possible outcomes of the studies include some limitations of LNG exports and stricter conditions for licence extensions. Therefore, it is important that the pause ends in a timely manner without waiting a conclusion of the ongoing extensive study at the Department of Energy (DOE). The pause has already caused reputational risks and uncertainties, the monetary effects of which are hard to quantify, but resuming the approval process will at least ensure that the pause's negative impact on national interest of the United States is minimised. The effect of the work being done at the DOE examining the impacts of recent policies regarding LNG is the same as the pause on exports. Further delays in supplying LNG to destinations that are still developing their infrastructure and demand for the resource could impact their transition from coal to gas. These destinations will need to consider potential future supply disruptions as they plan their energy transitions.

Table 4.2. Issues to Watch on the 'Pause'

Issue	What is Known
Direct impact of the pause	30 mt out of 150 Mtpa long-term deals in 2022/2023
48 bcf/d (365 Mtpa) authorised; 26 bcf/d (200 Mtpa) to be realised	22 bcf/d without a FID, no assurance
Disagreements between commercial and regulatory progress	Regulators do not directly take account of commercial arrangements, but something should be done
Licence extensions are said to be unaffected	Extension reviews are closely watched
Uncertain when the review process will resume	Timelines should be specified (the study and comment period)
Public comment period	Parties should start preparing impactful comments immediately (today)
Other LNG projects may benefit from the pause	Some projects within and outside of the United States
Possible outcomes of the studies	Upper and/or time (adjustable) limits of LNG exports Tougher (adjustable) standards for license extensions

bcf/d = billion cubic feet per day, LNG = liquefied natural gas, mt = million tonnes, Mtpa = million tonnes per year, FID = final investment decision.
Source: Analysis by Institute of Energy Economics, Japan.

Figure 4.9. EIA Projects a Steady Rise in United States Net Exports over 2022–2030 Interval



Bcf/d = billion cubic feet per day, CY = calendar year, EIA = Energy Information Administration, LNG = liquefied natural gas, US = United States.

Notes:

1. CY 2022–2024 data is from the EIA's May Short-term Energy Outlook (STEO). CY 2025–2030 data from the EIA's March Annual Energy Outlook 2023.
2. The AEO forecasts net LNG imports. In CY 2022, the US imported 0.07 Bcf/d of LNG per EIA STEO data.

Source: Based on data from Energy Information Administration.

Table 4.3. US Liquefaction Projects Appearing to Approach Operation and Financial Investment Decisions

Project	Owner	Estimated Internal In-Service Date	Capacity(Bcf/d)	FID Date Received	Est. FID Decision Date
Plaquemines 1	Venture Global	CY2024	1.3	May-22	
CCL Stage 3	Cheniere	CY2024	1.3	Jun-22	
Golden Pass Train 1	ExxonMobil/QatarEnergy	CY2025	0.7	Feb-19	
Golden Pass Train 2	ExxonMobil/QatarEnergy	CY2025	0.7	Feb-19	
Plaquemines 2	Venture Global	CY2026	1.3	Mar-23	
Golden Pass Train 3	ExxonMobil/QatarEnergy	CY2026	0.7	Feb-19	
Port Arthur Phase 1 T1	Sempra LNG	CY2027	0.9	Mar-23	
Rio Grande T1	NextDecade	CY2027	0.7	Jun-23	
Texas LNG	Glenfame	CY2028	0.5	-	CY2024
Rio Grande T2	NextDecade	CY2028	0.7	Jun-23	
Port Arthur Phase 1 T2	Sempra LNG	CY2028	0.9	Mar-23	
Cameron LNG T4	Sempra LNG	CY2028	0.9	-	CY2025
Rio Grande T3	NextDecade	CY2029	0.7	Jun-23	
Freeport LNG T4	Freeport LNG	TBD	0.7	-	TBD
Driftwood LNG Phase 1	Tellurian	TBD	2.2	-	TBD
Delfin FLNG 1	Delfin Midstream	TBD	0.4	-	TBD
Driftwood LNG Phase 2	Tellurian	TBD	1.4	-	TBD
Delfin FLNG 2-4	Delfin Midstream	TBD	1.3	-	TBD
Rio Grande T4	NextDecade	TBD	0.7	-	CY2024
Rio Grande T5	NextDecade	TBD	0.7	-	TBD
Alaska LNG	AGDC	TBD	2.6	-	TBD
Gulfstream LNG	Gulfstream LNG	TBD	0.5	-	TBD
CC Midscale T8-9	Cheniere	TBD	0.4	-	CY2025
Sabine Pass Stage 5	Cheniere	TBD	1.8	-	CY2026
CP2 Phase 1	Venture Global	TBD	1.3	-	TBD
Commonwealth LNG	Kimmeridge	TBD	1.1	-	CY2025
CP2 Phase 2	Venture Global	TBD	1.3	-	TBD
Lake Charles LNG	Energy Transfer	TBD	2.2	-	TBD
Magnolia LNG	Glenfame	TBD	1.2	-	TBD
FLNG	New Fortress Energy	TBD	0.4	Jan-21	
Port Arthur Phase 2	Sempra LNG	TBD	1.8	-	TBD
Qilak LNG	Qilak LNG	TBD	0.5	-	TBD
Delta LNG	Venture Global	TBD	0.7	-	TBD
Gulf Phase 1-2	Kinder Morgan	TBD	1.4	-	TBD
Total	-		**36.0**	-	-

Bcf/d = 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.

5.3. Highlights from IEEJ, ERIA, EPRINC Webinar

In late July 2024, the Institute for Energy Economics Japan, the Energy Policy Research Foundation (EPRINC), and the Economics Research Institute for ASEAN and East Asia hosted an online workshop, as part of this study: 'Risks and Opportunities for LNG's Future in Asia: Addressing Supply Concerns and Understanding LNG's Role in the Energy Transition in Asia (Emerging and Traditional LNG Markets).' Of special concern were assessments and policy discussions concerning the long-term availability of LNG exports from the United States to Asia and developments throughout the emerging economies to build out long-term and sustainable demand for LNG.

Two statements at the political level were mentioned as they had notable future implications. The first was from the Group of Seven (G7) Communiqué, which emphasised '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.' The second statement was from the United Nations Climate Change Conference (COP28) Global Stocktake (December 2023), which stated 'UNFCCC Parties recognize that transitional fuels can play a role in facilitating the energy transition while ensuring energy security.'

In late July 2024, two US senators introduced the Energy Permitting Reform Act of 2024. The bill would set a 90-day deadline for the Secretary of Energy to grant or deny LNG export applications following environmental reviews, with applications deemed approved if the Secretary fails to meet the deadline. The bill aims to ensure fact-based decision-making by requiring the Secretary to base decisions on the DOE's existing LNG economic and emissions studies, unless and until new studies are completed. This would solve a major issue that the LNG industry is experiencing.

Chapter 5
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.

1. Clearly Define an Important Role of LNG and Natural Gas in Energy Security and Energy Transition

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.

1.2. Flexibly Apply Climate Mitigation Measures – Clarify International CCS 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 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.

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 region's economies can advance to establish a healthier and more sustainable LNG market.

For the reader's 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.'

2. Secure Sufficient Long-term Supply Sources

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.

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 true that current export permission pause has been increasing the uncertainty especially for future projects, which have not obtained approval to export to non-free trade agreement countries by the US Department of Energy. The result of the United States presidential election in November 2024 would also be notable to see how this pause would be considered.

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, 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.

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 are purchasing 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.

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.

3. Enhance Purchasing Power

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.

3.2. Consider 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.

4. Improve Contract Terms and Conditions

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.

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.

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.

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