ERIA Research Project Report FY2023 No. 29

Mitigating Extreme Volatility of LNG Prices in ASEAN: Impacts of High LNG Prices on Southeast Asia

Edited by

Hiroshi Hashimoto

Han Phoumin

Mitigating Extreme Volatility of LNG Prices in ASEAN: Impacts of High LNG Prices on Southeast Asia

Economic Research Institute for ASEAN and East Asia (ERIA)
Sentral Senayan II 6th Floor
Jalan Asia Afrika No. 8, Gelora Bung Karno
Senayan, Jakarta Pusat 10270
Indonesia

ERIA Research Project Report FY2023 No. 29
Published in March 204

Note: $ in this publication refers to US dollars unless otherwise specified.

Preface

While liquefied natural gas (LNG) has numerous advantages and can enhance Asia's economic competitiveness, environment, and energy security, there are several issues and challenges to promoting LNG in the region, particularly after the global energy crisis in 2022. In the 2021 study conducted by the Economic Research Institute for ASEAN and East Asia ('A Flexible LNG Market and Promotion of Investment'), the following policy recommendations were presented:

1. Policy support is needed to sustain infrastructure development.
2. Create more gas demand with innovative solutions to facilitate further investment: TPA (third-party access), ssLNG (small-scale LNG), ISO tanks, LNG-to-powership, and virtual pipeline system.
3. Producers and consumers should make the best efforts to reduce the carbon footprint of LNG in the supply chain and at the consuming end and eventually to zero.
4. Pursue an LNG pricing mechanism that provides comfortable price levels for consumers and producers.
5. Pursue flexible terms and conditions in LNG contracts by constantly monitoring market activities and close communication with competition authorities.

The study, 'Mitigating Extreme Volatility of LNG Prices in ASEAN: Impacts of High LNG Prices on Southeast Asia', investigates what happened to the LNG market in ASEAN and surrounding regions, 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. Indeed, the volatility and its implications, especially extremely high prices, have created difficulties in procuring LNG in the spot LNG market, leading to delays in project implementation and plans. Some players and economies have found opportunities to develop new resources. At the same time, the region has increasing challenges to balance 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

Acknowledgements

This study was undertaken based on close discussions with LNG specialists and industry officials in ASEAN, Japan, and the United States (US). The authors would like to thank all the participants in the online LNG workshop meeting on 21 June 2023 and the respondents to the written survey on destination flexibility issues.

The presentations at the workshop – from the region's industry players, government authorities, and stakeholders from the other areas, which are also active in Southeast Asia and the US – and ensuing discussions were very useful and inspiring to develop future strategies and policy measures to support development activities.

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

Hiroshi Hashimoto

Leader of the Working Group

List of Project Members

Leader	Hiroshi Hashimoto	Senior Fellow, Institute of Energy Economics, Japan (IEEJ)
Sub-leader	Kiminori Maekawa	Senior Research Fellow, IEEJ
Member	Yusuke Hidaka	Senior Researcher, IEEJ
	Hisao Kawakami	Senior Researcher, IEEJ
	Yoshimasa Mori	Senior Researcher, IEEJ

Table of Contents

List of Figures

List of Tables

List of Abbreviations and Acronyms

APERC	Asia Pacific Energy Research Centre
Bcf	billion cubic feet
Bcm	billion cubic metres
Bcf/d	billion cubic feet per day
Bcm/y	billion cubic metres per year
CCS	carbon capture and storage
CM	cubic metre
CME	Chicago Mercantile Exchange
CY	calendar year
DES	delivered ex-ship
DOE	Department of Energy
EGAT	Electricity Generating Authority of Thailand
EIA	Energy Information Administration
EPC	engineering, procurement, and construction
EPRINC	Energy Policy Research Foundation, Inc.
EU	European Union
FERC	Federal Energy Regulatory Commission
FID	final investment decision
FLNG	floating LNG facility
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
ISO	International Organization for Standardization
JKM^{TM}	Japan Korea Marker

LNG	liquefied natural gas
MBtu	million British thermal units
MOU	memorandum of understanding
Mscf	million standard cubic feet
Mscf/d	million standard cubic feet per day
Mt	million tonnes
Mtoe	million tonnes of oil equivalent
Mtpa	million tonnes per annum
PDP	Power Development Plan (Viet Nam)
PGC	Potential Gas Committee
PJ	petajoule = 10^{15} joule
SPA	sales and purchase agreement
Tcf	trillion cubic feet
TTF	Title Transfer Facility
US	United States of America

Introduction

After several years of relatively low and extremely low spot liquefied natural gas (LNG) prices (in 2020), the world of LNG entered a prolonged period of unprecedented extremely high levels of spot LNG prices. In the first half of 2023, the market experienced a rather unexpected softening of prices, but still relatively expensive with some potential risk factors of rising again.

Such volatility has caused harm to the healthy development of the LNG market in the 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 the ASEAN and East Asian regions 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 5 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) in Tokyo 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 renewables, the share of natural gas in the energy mix in ASEAN is expected to expand from 19% in 2020 to 24% in 2050, according to IEEJ Energy Outlook 2023.

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 the 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 to 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, intra-regional LNG trades, 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 after 210 million tonnes per year of capacity was sanctioned from 2017 to the first half of 2023. Notably, for those projects that got final investment decisions during the period, more than half of assumed volumes have not decided their final destinations. Those new projects will compete for LNG customers against each other, 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 rather vertically integrated manner. Those with LNG volumes to be supplied 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, and upstream developers, in collaboration with Japanese commercial banks and governmental organisations, have already been active in other countries – notably 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 has experienced a very turbulent period (from 2020 to the first half of 2023) due to the 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 into the persistently high prices after the second half of the year. Then, the developments were followed by even extremely higher prices in the period after the Russian military invasion of Ukraine and relatively calming down in the first half of 2023.

During the past turbulent years, the world again learned 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 early 2023.

The 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.

The study aims to identify how LNG and natural gas price volatility can or should be mitigated, especially in the ASEAN region. It would reduce prices and make those prices acceptable to consumers and producers – more stable, predictable, affordable, and sustainable. The study will look at recent and expected developments of price formation in the LNG markets and see what can be done to promote more suitable price benchmarks in the region per evolving LNG pricing developments.

For the Asian LNG market to flourish, new supplies 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 price discovery reflects supply and demand fundamentals.

Executive Summary and Key Findings

The study report starts with the recent developments in the volatile global LNG markets, including major regions, focusing on price fluctuations and their causes – mainly rapidly changing market balances. The authors notice that prices worldwide move faster and wilder these days, changing directions relatively shorter than their movements a few years back. When prices rise, they are extermely high. When they fall, they are extremely low, and sometimes they are traded in negative price territories in some areas, meaning that sellers pay off-takers for off-takes.

Then, the authors looked at gas supply and demand developments in Southeast Asian economies concerning economic growth and impacts of the global energy crisis, including prospects of natural gas and LNG market development and growth. This is particularly interesting for the region, including traditional gas-producing and LNG-exporting countries and prospective LNG-importing countries. In the middle of 2023, the Philippines and Viet Nam started LNG imports. The growth of those emerging LNG markets will depend on global LNG market developments. Also within the region, Myanmar, which began LNG imports in 2020, has already ceased importing LNG, at least for the moment, mainly because of the unstable and unaffordable LNG market – an expensive and tight spot LNG market.

The ASEAN region also includes traditional LNG exporters – Brunei Darussalam, Indonesia, and Malaysia. Indonesia and Malaysia, still developing additional LNG production projects, sometimes in different arrangements and business models, have also started using LNG in their domestic markets for some years.

The region's economies recognise the need to take care of their respective energy transition agenda, including expanded use of renewable energy and enhanced energy-saving measures. They are mostly planning to increase the use of LNG and natural gas in the future – including the respective transition period and after that.

Then, multiple factors of amplified price volatility are described and investigated. Those include the European Union's (EU’s) significant shift to more LNG import, at least for the medium term and potentially long term, but also fundamental factors apparent even before the Russian invasion of Ukraine starting in February 2022. China's recent gigantic natural gas market growth has contributed to the rapid growth of the global LNG market and has caused some seasonal tightness in its winter months. India and its South Asian neighbours are also examined in contrast with Southeast Asia and China. The report also looks at short-term outages and troubles in the LNG production side as market-shaking factors, which have been more frequently observed but sometimes not publicly reported.

In connection with fluctuating gas prices, different settings of wholesale gas prices are also observed in the report, both historically and regionally.

LNG supply from the United States (US), a major source expected to underpin the growth of LNG-consuming markets worldwide, is also examined. This is especially important as consumers would not want to rely on energy sources that would not assure long-lasting and affordable supply for their future economic growth. LNG supply from the US would not come without its challenges. But its huge potential and expected flexibility in destinations and prices are certainly most attractive to emerging consumers in the region.

The report comes up with a list of recommendations:

- ✓ Secure sufficient long-term supply sources.
    - ➢ Increase supply from existing LNG production projects and prolong the life-expectancy of those projects
    - ➢ Expand new supply sources in North America, Australia, and East Africa
    - ➢ Focus on brownfield opportunities and the Pacific Coast of North America
    - ➢ Consider options in Russia after the normal conditions return
    - ➢ Consider alliances with buyers in Japan and take advantage of pooling infrastructure on the LNG receiving side
- ✓ Enhance purchasing power.
    - ➢ Aggregate demand in the region to optimise cargo flow
    - ➢ Consider partnerships with buyers in different regions to optimise seasonality in other regions.
- ✓ Alter contract terms and conditions.
    - ➢ Introduce measures to mitigate fluctuations in prices while not distorting market activities.
    - ➢ Consider measures that enable larger and longer off-take and delivery commitments.
    - ➢ Reduce destination restrictions further to optimise cargo movements more
    - ✓ Alter the limitations and restrictions in climate goals.
    - ➢ Flexibly apply climate mitigation measures – Clarify international standards of carbon capture and storage (CCS), reductions of flaring, and other decarbonisation measures alongside the value chain
    - ➢ Equitably evaluate impacts of coal-to-gas conversion in the region
    - ➢ Governments to provide proper guidance and support measures

The authors hope these recommendations will lead to further productive discussions and initiatives to improve and flourish the LNG industry, especially in the ASEAN region.

Chapter 1

Highly Volatile LNG Prices

1. Outline of Price Fluctuations

The global LNG and natural gas industry has experienced an extraordinarily volatile period (2020–2022) due to not only the COVID-19 pandemic and the prolonged Russia–Ukraine War and their impacts on the global economy but also many other factors.

During 2020, with extremely low spot LNG prices, some project development activities were kept stagnant with only an investment decision for only 3.25 million tonnes per year of LNG production capacity. Then, at the beginning of 2021, the spot LNG prices soared, sometimes even sky-rocketed to record highs, culminating in the persistently expensive prices between the second half of 2021 and the end of 2022. Although since the beginning of 2023, the highly volatile spot prices have declined and been kept within the relatively lower price range, nearly as low as the price level of 2019, a resurgence of those price hikes is still possible, as the current situation is easy to change.

Factors for the above phenomena included the rapid demand recovery from the latter half of 2020 (after the pandemic-induced slump in the first half of the year) and the relatively slow recovery of natural gas production, which had declined due to sluggish demand. In the medium to long term, construction and investment for additional natural gas and LNG production have not caught on with the rapid pace of demand recovery.

Another factor is the unexpected troubles and outages at existing LNG production facilities. As a result, prices are expected to remain generally high until around 2025. They are expected to surge again, especially during the winter in the northern hemisphere when global gas demand peaks. The gas supply outlook remains uncertain, given the situation in Ukraine. The EU's use of more non-Russian gas means additional procurement from other sources, causing concerns over gas supplies to other markets. For now, amidst unprecedentedly high prices, stable natural gas procurement is a critical issue in global markets.

In the ASEAN region, the trend of highly volatile and still relatively high LNG prices has caused serious effects on economic development and steps towards decarbonisation. But it simultaneously has attracted investment in upstream and midstream natural gas development projects and speeded them up around the world.

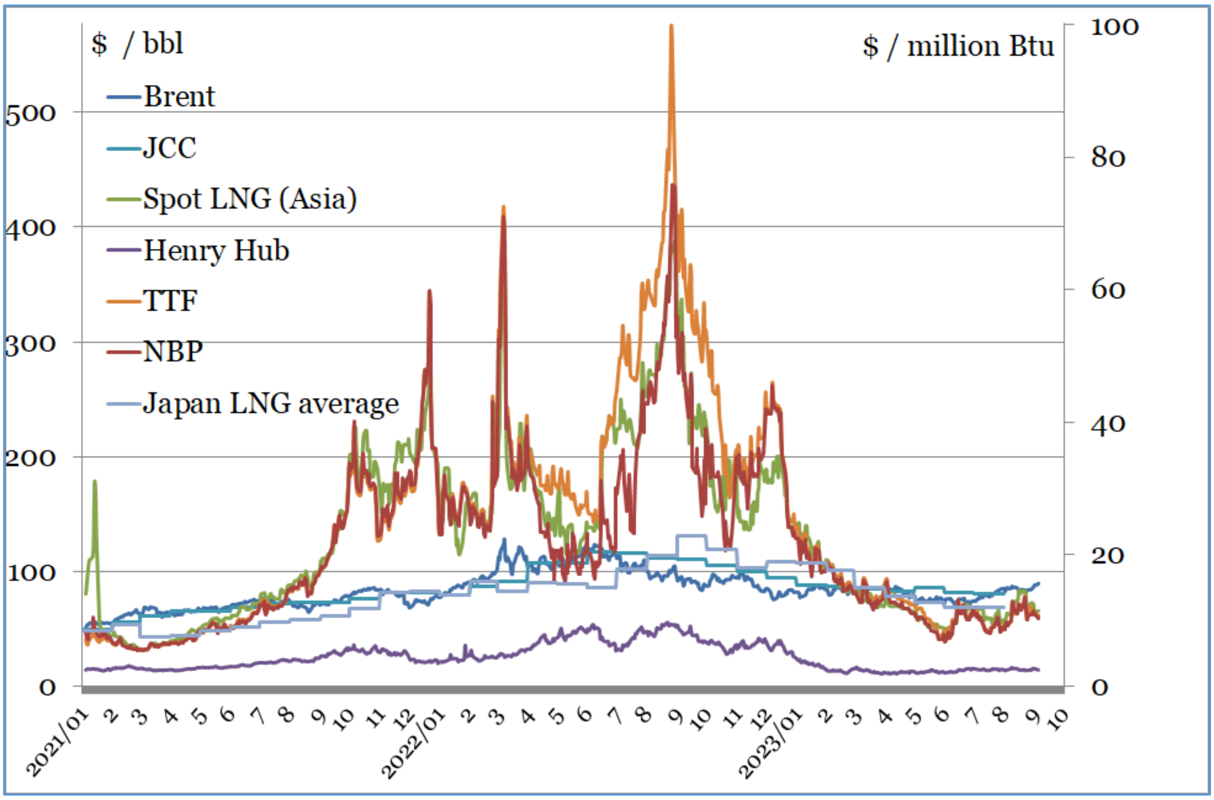
2. Global Gas Prices Move Faster and Wider than in the Past

In the second half of 2022, European Title Transfer Facility (TTF) prices (front-month futures prices) were exceptionally higher than other regional gas prices and more expensive than other periods in the past. Assessed Asian spot LNG prices tended to follow higher TTF to rise during the period.

Spot LNG and gas prices were more expensive than crude oil from August 2021 until April 2023, although the ordinary pricing range of LNG imported into Asian countries with 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.

In the second quarter of 2023, the spot prices have declined to the rate of before the turbulent period. However, they are still nearly five times as high as those of the 2020 level, which is giving a certain extent of difficulties to sound development of LNG markets and economic development in Southeast Asian countries (Figure 1.1).

Figure 1.1. Spot LNG Prices (2021–1H 2023)



Source: IEEJ Analysis.

There have been some major spikes in assessed Asian spot LNG prices between 2021 and 2022, and the prices have declined rapidly to the 2020 level since the beginning of 2023 (Table 1.1).

After the October 2021 price peak until the end of 2022, assessed Asian spot LNG prices were strongly driven high by European spot gas prices, which were heavily affected by many factors such as colder winter and supply shortages concerns.

Immediately after 24 February 2022, natural gas and LNG prices rose to record-high levels amidst ongoing geopolitical tensions since the Russian invasion of Ukraine. The TTF drove assessed Asian spot LNG prices to go up higher.

On 7 March 2022, the TTF (the settlement price of the front-month futures) hit $72/MBtu (€227.201/MWh) on fears of Russian pipeline gas supply disruptions, accompanied by assessed Asian spot LNG prices, which temporarily soared to $85/MBtu.

As the 2022 summer season began, the TTF rose due to Nord Stream's throughput reduction, marking $99/MBtu (€339.196/MWh) on 26 August. However, after that, European underground gas inventories piled up steadily amidst the record-high temperatures in the 2022–2023 winter season. Assessed Asian spot LNG prices also fell to the mid-$10/MBtu range by the middle of July 2023 due to thin buying from Japan and China, which have ample stocks.

Table 1.1. Major Spikes in Spot Prices (2021–1H 2023)

	Assessed Asian Spot LNG Prices Price at the Peak and Circumstances in Asian Market	**TTF Price at the Peak and Circumstances in the European Market**
10/2021	**$56/MBtu** Rise of European spot prices Severe Winter	**$54/MBtu** Severe winter expectation Power supply shortages Low inventory in gas storage Supply shortages (concerns) - Pipeline gas supply from Russia Price Hike of EU-ETS
12/2021	**$44/MBtu** Rise of European spot prices Severe winter Supply shortages (concerns) - LNG supply outages - Diversion of LNG to Europe	**$60/MBtu** Severe winter Power supply shortages Low Inventory in gas storage Supply shortages (concerns) - Pipeline gas supply from Russia
02/2022	**Russian Invasion of Ukraine**	
03/2022	**$84.8/MBtu** Rise of European Spot Prices Supply Shortages (Concerns) - LNG Supply Outage Concern - Diversion of LNG to Europe	**$72/MBtu** Supply shortages (Concerns) - Pipeline Gas Supply from Russia
08/2022	**$71/MBtu** Rise of European spot prices	**$94.2/MBtu** Supply shortages (concerns) - Maintenance of Nord Stream 2 - Maintenance of gas fields in Norway
12/2022	**$40/MBtu** Severe winter End of Zero-COVID-19 Policy in China	**$46.1/MBtu** Decreasing pipeline gas supply from Russia Concern over power shortages Nuclear outages in some countries

Source: IEEJ Analysis.

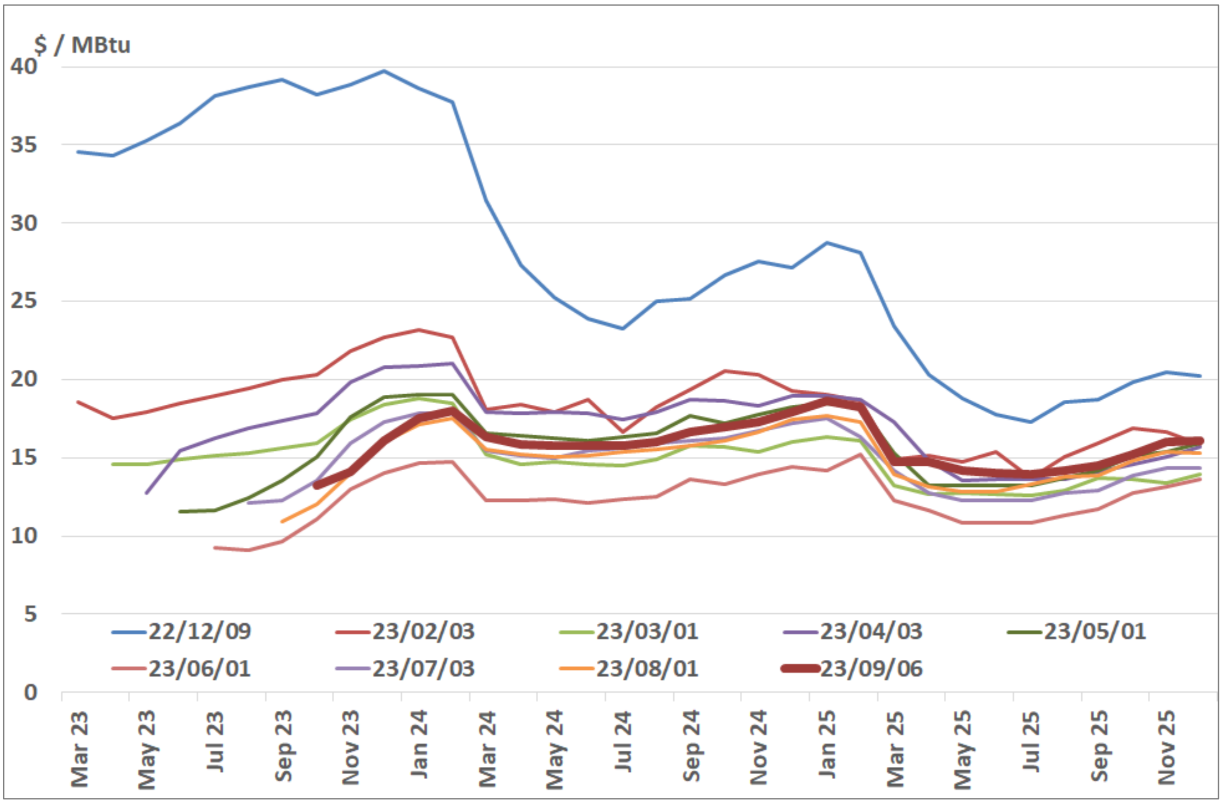
3. Market Sentiments Can Shift Very Quickly

Spot LNG and gas prices trended down from the end of December 2022 until the end of the first half of 2023. As of June 2023, LNG prices on the spot market have fallen to pre-2020 levels of $7–13/MBtu for both assessed Asian spot LNG prices and TTF. Individual circumstances – such as increased demand from China and India, supply concerns due to extended repair periods for gas production facilities in Norway, etc. – have caused fluctuations of up to $5/MBtu. However, such situations have not brought about any major spikes in the spot market prices thus far in 2013.

Spot price expectations for 2023 were in the $30s at the end of 2022, although they were in the teens as of the beginning of July 2023 (Figure 1.2). The widening volatility has negatively impacted the function of futures trading, which is supposed to guarantee risk hedging, as margin rates for JKM™ derivatives on the Chicago Mercantile Exchange have increased, the financial exchange with the highest trading volume for JKM™ derivatives, remaining above 30% since October 2022. Over the past few years, trading volumes, rising steadily until 2020, have stagnated. High price volatility has led to a cycle of higher costs to secure margins and lower liquidity, leading to more volatility.

However, market sentiments can shift very quickly at any time. It is possible to go from the range of traded prices as of June 2023 to a very distant range if multiple factors affecting LNG supply come together.

Figure 1.2. Changes in JKM Forward Curves



Source: Based on Data of Chicago Mercantile Exchange.

Chapter 2

Supply–Demand Situation in Southeast Asian Countries

1. Outline of Gas Demand in ASEAN

1.1. Economy and Energy Demand Outlook

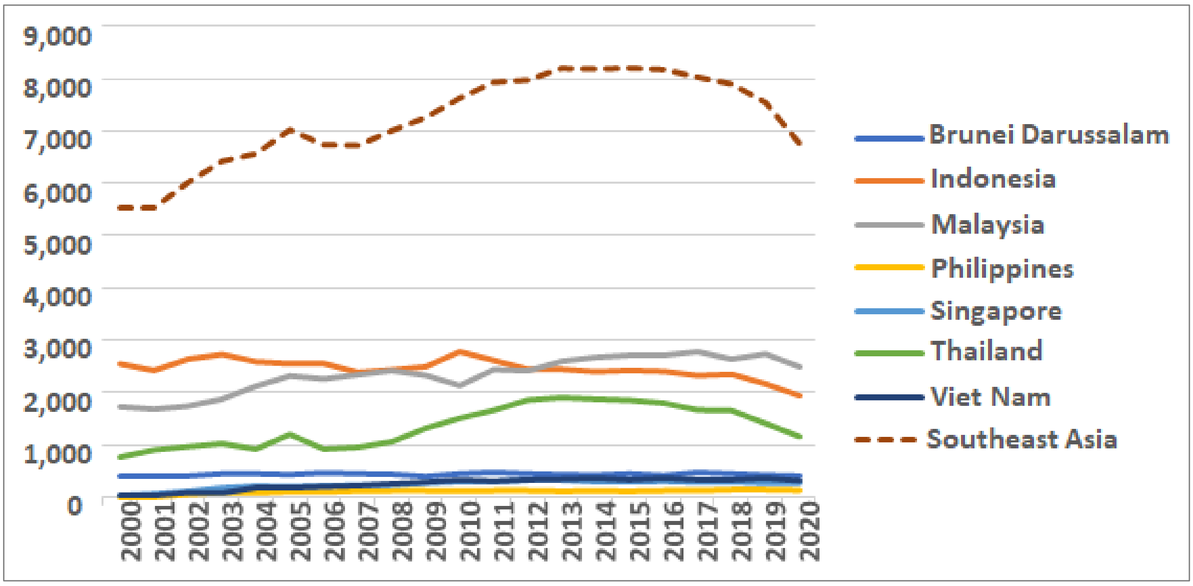
In some Asian nations, LNG has acquired a reputation as a costly and unreliable fuel. Proposed LNG import projects in the region faced increasing delay and cancellation risks. At the same time, governments in key LNG growth markets have announced new policies designed to limit dependence on global gas imports. This has clouded prospects for long-term demand in the regions that the global LNG industry had been counting on for robust growth. These trends indicate that considerable engagement will be needed, especially throughout Southeast Asia, to restore confidence in LNG as a cost-effective, resilient, and reliable fuel source for the region.

The LNG market structure is not viewed as robust enough yet in the ASEAN region. The region is a future significant user of natural gas because more countries plan to use more natural gas. Stable and extra natural gas production could play a significant role in energy security in this region. While the region needs to use more gas, sustainability and vulnerability of gas prices could be more important issues to be discussed in ASEAN and East Asia if the economies in the region want to promote the future use of more natural gas.

Energy demand is growing very rapidly in Southeast Asia. Countries in the region are grappling with power shortages due to rising demand and climate-related constraints. The risk of high energy costs and market volatility leaves the countries with difficult choices to fill the gap. Southeast Asian nations confront the challenge of reconciling energy security, affordability, and economic development with the need to tackle climate change.

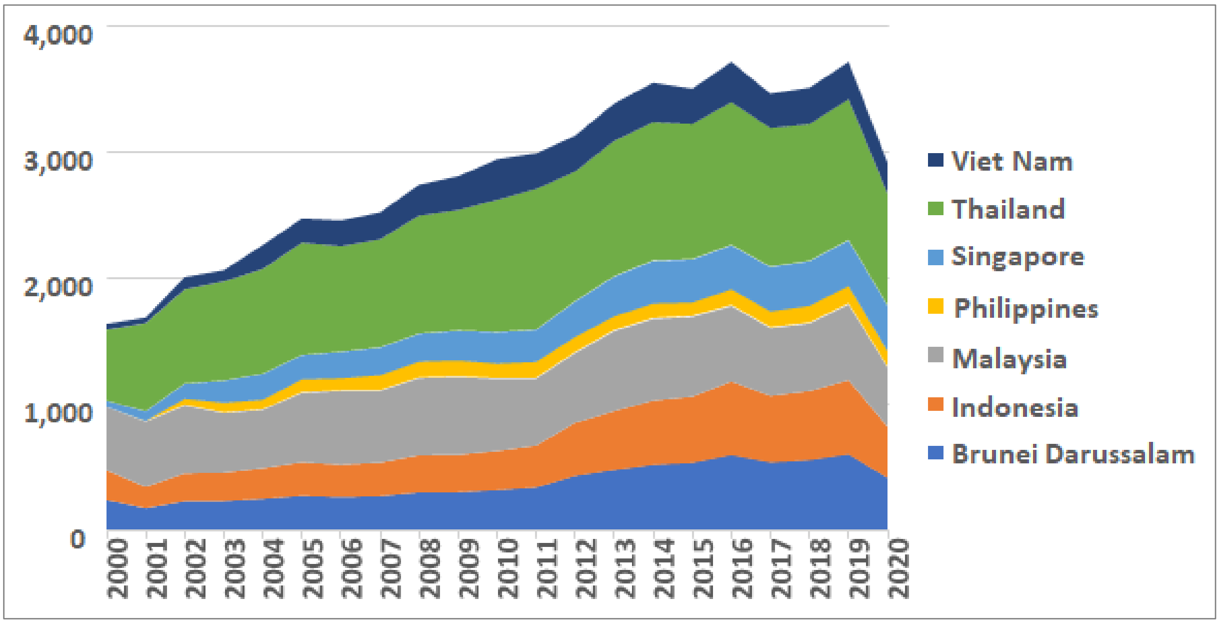
There has been a strong gas demand growth in the ASEAN region for more than 20 years, driven by significant economic and population growth. The gas demand doubled, especially for the power sector, between 2000 and 2020 (Figures 2.1 and 2.2).

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



Source: Based on data from APERC.

Figure 2.2. Gas Consumption for Electricity Generation (PJ)

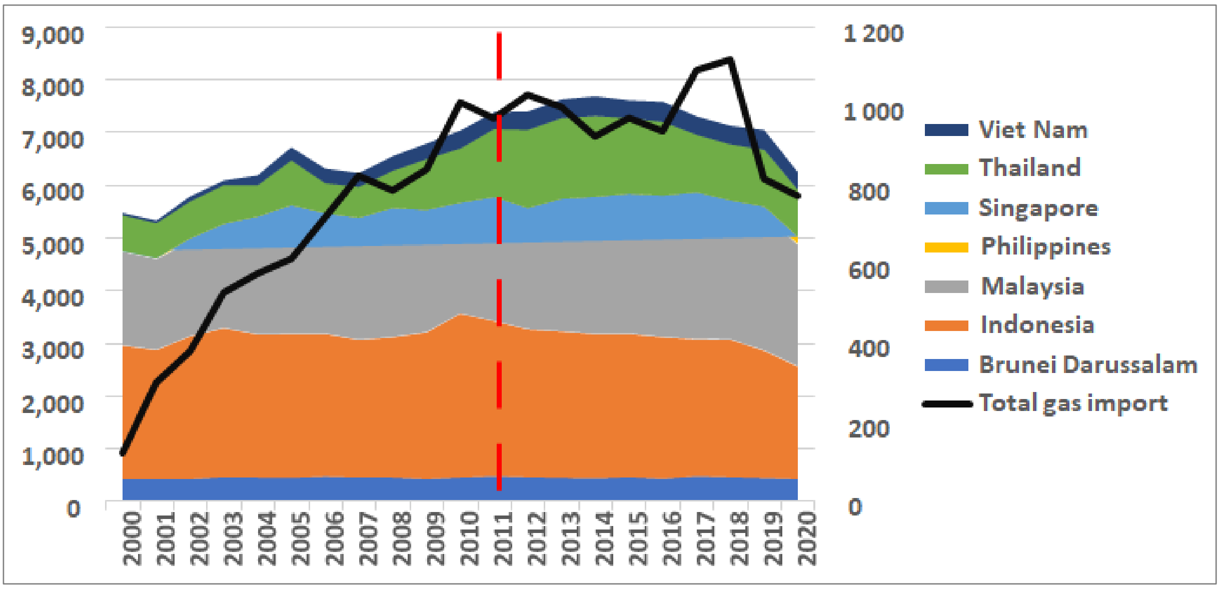


Source: Based on data from APEC Energy Working Group Expert Group on Energy Data and Analysis (EGEDA).

1.2. Production and Import of Natural Gas

Indonesia, Malaysia, and Thailand have been consuming more than 80% of the total demand 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 been importing gas from Indonesia and 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 because of its circumstances.

Figure 2.3. Gas Production and Imports (PJ)



Source: Based on data from APEC Energy Working Group Expert Group on Energy Data and Analysis (EGEDA).

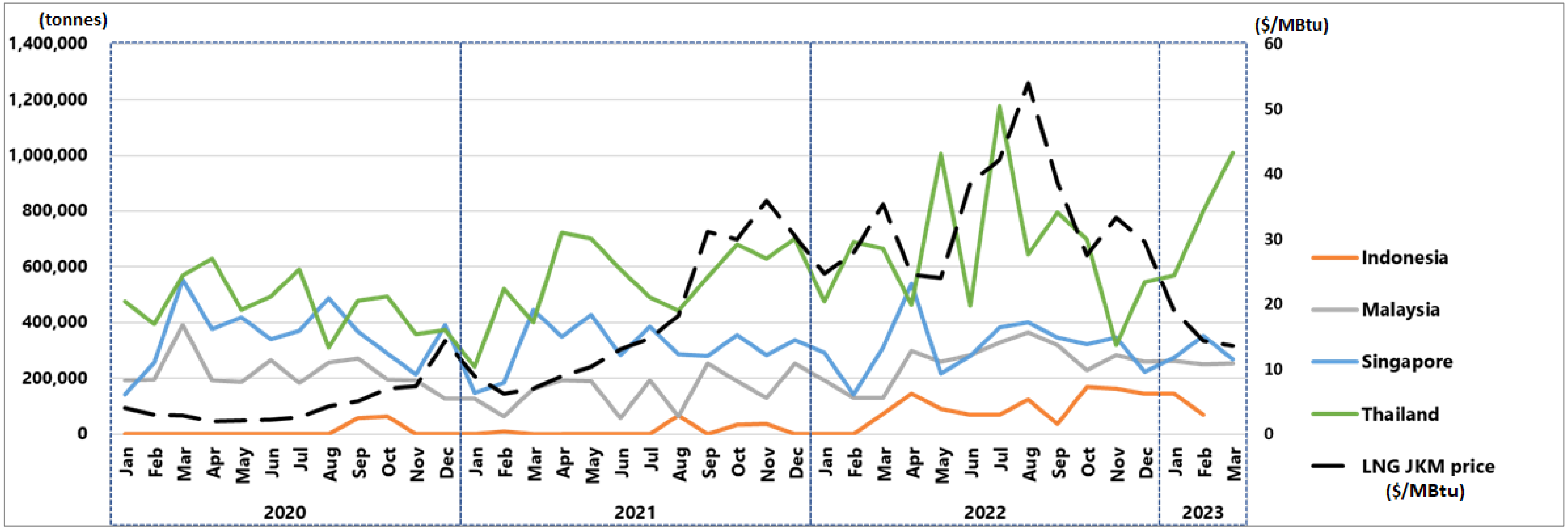
1.3. LNG Spot Prices and Imports

From the second half of 2021 to 2022, limited LNG supplies and the Russia–Ukraine War caused assessed spot LNG prices to rise to unprecedented levels. But 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.

As Figure 2.4 shows, in the first half of 2023, taking advantage of the lowered 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 Abu Dhabi of the United Arab Emirates. Viet Nam also started importing LNG in July.

By May 2023, assessed Asian LNG spot prices have declined significantly, back to the first half of 2021 levels. This has incentivised several LNG importers, particularly Thailand, to accelerate LNG imports to sustain their energy security. However, at the same time, 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. This is also due to the decline of gas production at the Malampaya gas field in the Philippines. Viet Nam 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 2.4. LNG Spot Prices and Imports by Nation



Source: Based on data from Cedigaz and Investing.com.

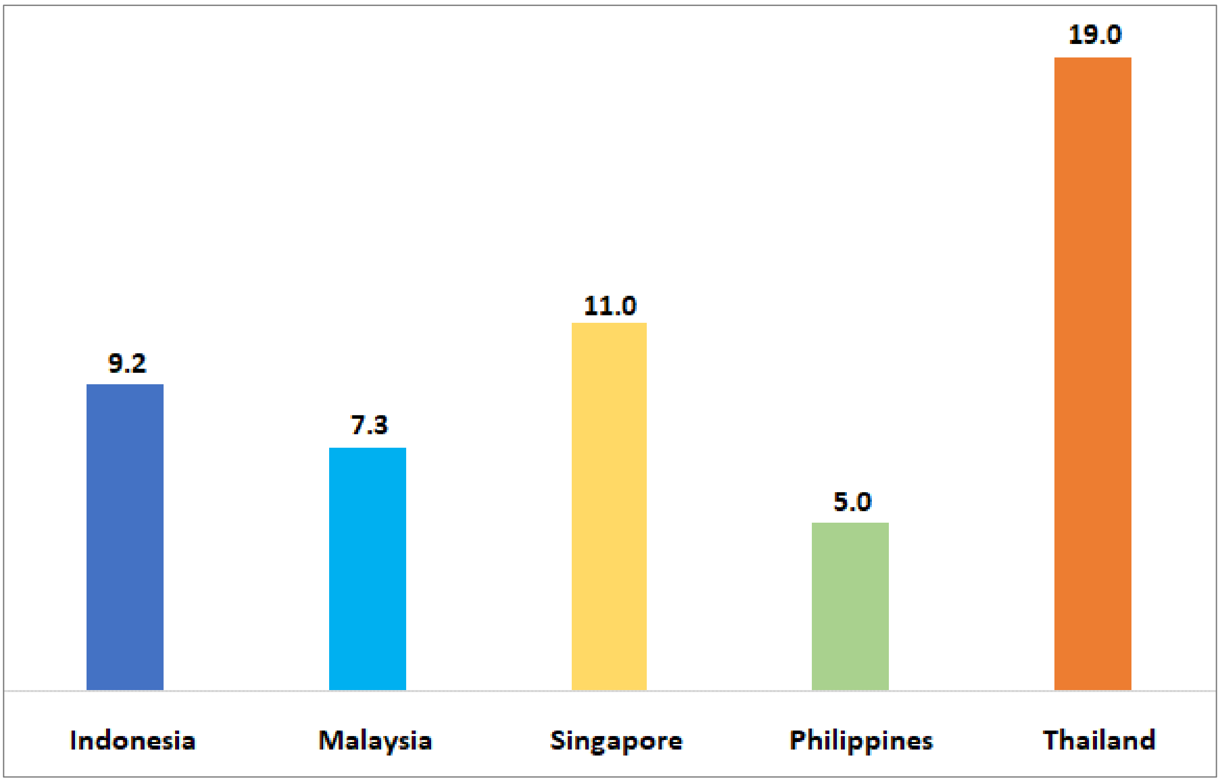
1.4. LNG-receiving Terminals in Southeast Asia

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

- 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.

Figure 2.5. LNG-receiving Terminal Capacity as of April 2023 (Mtpa)



Source: Based on data from Cedigaz.

2. Thailand

2.1. Economy and Energy Demand Outlook

According to IEEJ Outlook 2023, Thailand's primary energy consumption is forecast to increase by an average of 1.2% per year, based on an assumed economic growth rate (2015 prices) of 3.0% annually from 2020 to 2050. The energy mix in 2050 will comprise 7.1% coal, 36% oil, 20% natural gas, 3.2% nuclear, 0.6% hydro, 26% biomass and waste, 3.7% solar, wind, etc. (Table 2.1).

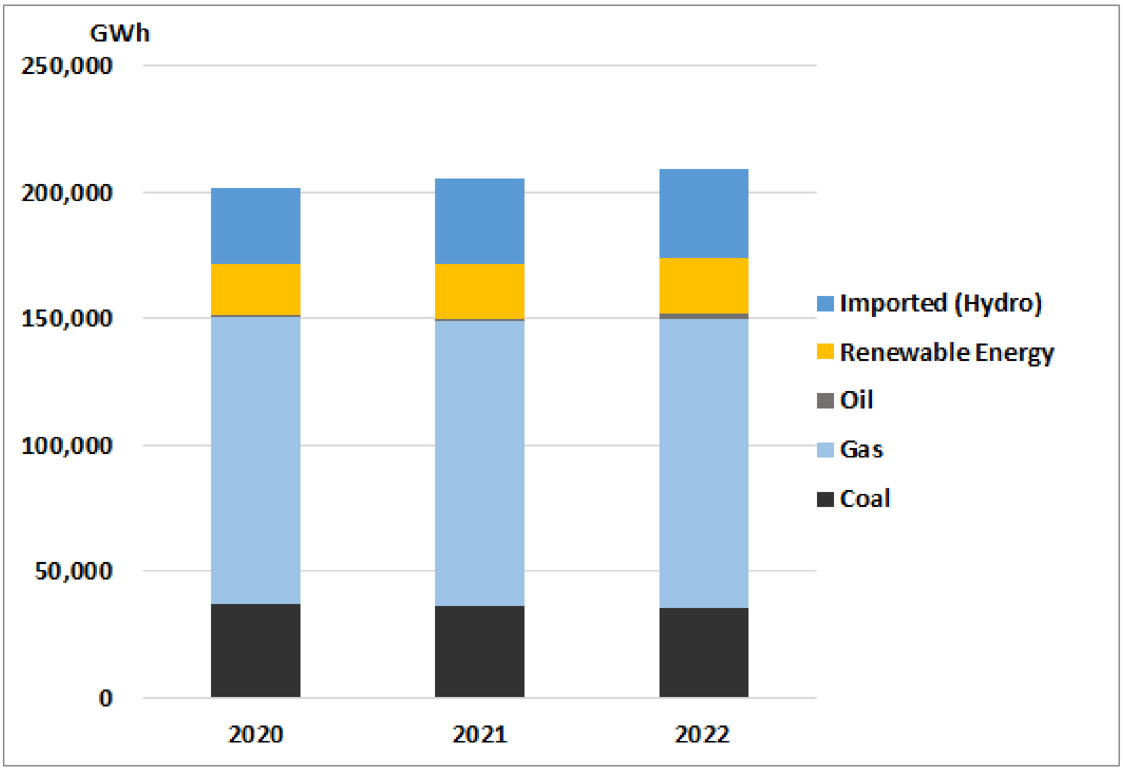
Table 2.1. Primary Energy Consumption in Thailand

	Mtoe							Shares (%)		
	1990	2000	2010	2020	2030	2040	2050	1990	2020	2050
Total	42	73	118	133	159	179	193	100	100	100
Coal	3.8	7.7	16	17	15	15	14	9.0	13	7.1
Oil	18	32	45	55	63	68	70	43	41	36
Natural gas	5.0	17	33	35	39	41	38	12	26	20
Nuclear	-	-	-	-	-	1.8	6.2	-	-	3.2
Hydro	0.4	0.5	0.5	0.4	0.9	1.0	1.1	1.0	0.3	0.6
Geothermal	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	-	0.7	2.4	4.6	7.2	-	0.5	3.7
Biomass and waste	15	15	23	23	35	43	51	35	17	26
Hydrogen	-	-	-	-	-	-	-	-	-	-

Source: IEEJ (2022).

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.

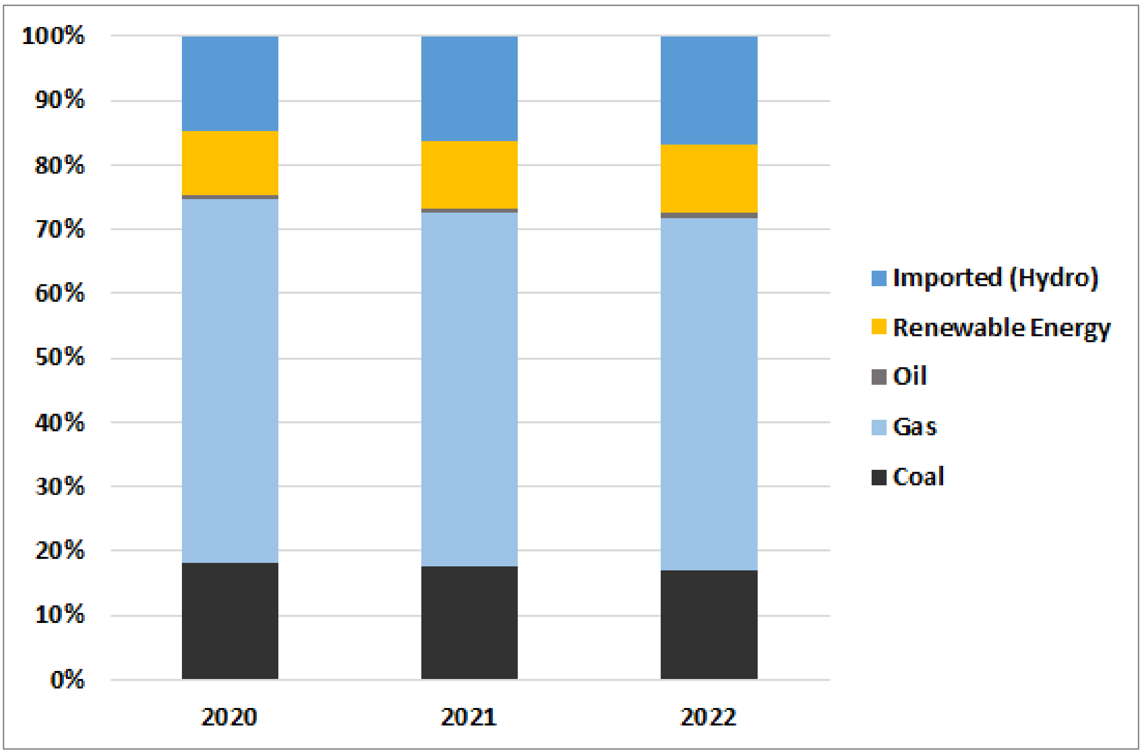
Figure 2.6. Annual Power Generation by Fuel Type, 2020–2022 (GWh)



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

Gas remains Thailand's dominant fuel for power generation, although the share has 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 could be the direct result of the government's policy to reduce the gas share in their power generation mix while increasing the renewables impact for the power generation at the same time.

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



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

2.2. Natural Gas Industry

PTT, state-owned under the Ministry of Energy's jurisdiction, 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 be continuously consumed mainly for power generation, the government works to expand domestic production, diversify import sources, and improve the gas infrastructure.

The government tries to secure gas in domestic and overseas fields to meet domestic gas demand. Thailand started gas imports from Myanmar through pipelines in 1998. The country also started importing LNG in 2011. The receiving terminal expansion is underway. Concerning LNG, the country 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 on 2P (Proven and Probable) basis, managing natural gas procurement in line with domestic demand, following up on gas fields currently under development in Thailand, and reducing the share of gas-fired power generation to less than 70 %. 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 allowed in upstream 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 MOECO (Mitsui Oil Exploration Co.) 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 km. The PTT group has played a dominant role in the construction, ownership, and operation of gas transportation and LNG terminals and developing some gas fields. The Ministry of Energy, however, has been progressively developing rules for third-party use of onshore gas pipelines and LNG terminals.

Given the limitations on domestic gas resources, 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.

In December 2021, PTT announced the 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 an LNG-receiving terminal with a capacity of 5 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 Energy Ministry instructed PTT to consider procuring LNG on the spot market. Energy Minister Sontirat 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 entity, 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 April 2021, EGAT announced a plan to import LNG for THB70 billion over the next 5 to 7 years.

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 Mt of LNG under a long-term contract. Earlier, 5.2 Mt of LNG imports were authorised for

PTT. The purpose of the plan is to stabilise the rising prices of LNG.

3. Malaysia

3.1. Economy and Energy Demand Outlook

IEEJ Outlook 2023 forecasts Malaysia's primary energy consumption to increase by an average of 1.2% per year, based on an assumed economic growth rate (2015 prices) of 2.1% annually from 2020 to 2050. The energy mix in 2050 will comprise 10% coal, 21% oil, 61% natural gas, 2.1 nuclear, 2.2% hydro, 2.0% biomass and waste, 1.7% solar, wind, etc. (Table 2.2).

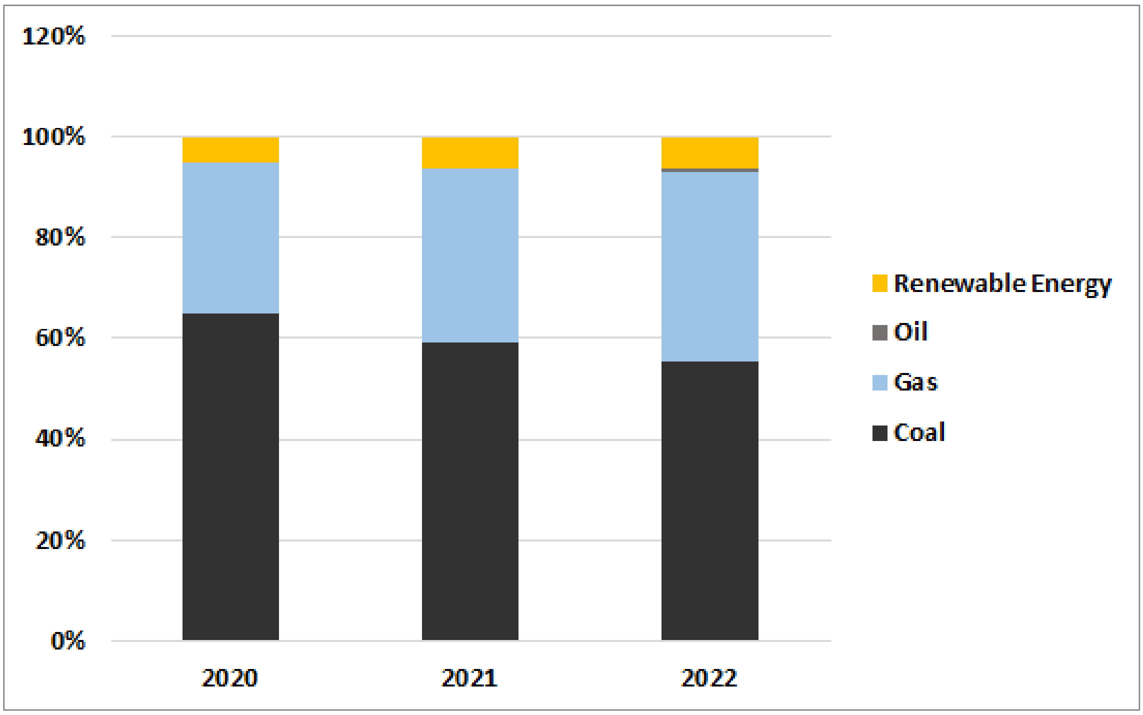
Table 2.2. Primary Energy Consumption in Malaysia

	Mtoe							Shares (%)		
	1990	2000	2010	2020	2030	2040	2050	1990	2020	2050
Total	21	48	72	92	142	161	172	100	100	100
Coal	1.4	2.3	15	22	22	21	18	6.4	24	10.0
Oil	11	19	25	31	41	39	36	54	34	21
Natural gas	6.8	25	31	36	73	88	104	32	39	61
Nuclear	-	-	-	-	-	3.7	3.7	-	-	2.1
Hydro	0.3	0.6	0.6	2.3	3.2	3.6	3.8	1.6	2.4	2.2
Geothermal	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	-	0.2	0.5	1.5	2.9	-	0.2	1.7
Biomass and waste	1	1	1	1	2	3	3	6	1	2
Hydrogen	-	-	-	-	-	-	-	-	-	-

Source: IEEJ (2022).

Figure 2.8 shows that gas took market share away from coal in Malaysia's power sector between 2020 and 2022 despite rising prices. Gas share increased from 30% to 37%, while coal share decreased from 65% to 56%. Malaysian domestic gas production grew during this period, underpinning the country's ever-growing demand for the power and industry sectors.

Figure 2.8. Share of Annual Power Generation by Fuel Type 2020–2022 (%)



Source: Based on data from 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, reaching 82.4 Bcm in 2022 (Energy Institute, 2023).

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

In March 2021, Petronas and China's CNOOC announced that they had signed a memorandum of understanding (MOU) for partnership in energy security, mainly in LNG and upstream sectors, and in developing environment-friendly energy. 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, which was under the influence of the Myanmar State Military and Japanese and Thai companies. However, international criticism was mounting that the revenues were funding the military regime.

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 km from the coast at Bintulu (Shell, 2022). The project is provided with electricity from renewable energy.

The facility can produce 800 Mscf/d 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 and is located close to the Pegaga field, which recently succeeded in producing commercial gas; a subsequent survey of the Pegaga field confirmed initial reserves of an additional 1 Tcf. Mubadala Energy operates SK 320 concession, holding a 55% interest. Petronas and a Shell subsidiary hold the remainder.

3.3. LNG Business: Export

Table 2.3 shows LNG liquefaction projects in Malaysia.

Petronas FLNG 1 was the world's 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	N.A.	Petronas, Sabah State Govt.

Source: IEEJ Analysis.

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 facility (FLNG) in Sabah on Borneo Island. The facility will have an LNG production capacity of 2 Mtpa, with FID revealed in early January 2023 (JGC Holdings Corporation, 2023).

In September 2022, Argentina's state-owned oil company YPF 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 Sabah-Sarawak Gas Pipeline (SSGP) KP201. This affected the gas supply to MLNG Dua's production facilities at Petronas LNG Complex (PLC) in Bintulu, Sarawak. The force majeure only affected gas supplies to MLNG Dua, while other LNG production facilities in the PLC are operating as planned. The incident affected supplies to LNG buyers under contract.

3.4. LNG Business: Import

LNG imports by Petronas began in 2013 to help alleviate gas shortages on the Malay Peninsula. 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.

In October 2020, Malaysian LNG importer Petrolife Aero 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 industrial sector. Malaysia's LNG market, which Petronas had monopolised, is now open.

In May 2022, Petronas signed a sales and purchase agreement (SPA) with US-based Venture Global LNG. The contract lasts 20 years and involves procuring 1 Mtpa of LNG from Venture Global's facility in Louisiana.

4. The Philippines

4.1. Economy and Energy Outlook

IEEJ Outlook 2023 forecasts the Philippines' primary energy consumption to increase by an average of 3.1% per year, based on an assumed economic growth rate (2015 prices) of 4.8% annually from 2020 to 2050. The energy mix in 2050 will comprise 20% coal, 41% oil, 15% natural gas, 15% geothermal, 0.8% hydro, 6.9% biomass and waste, 1.8% solar, wind, etc. (Table 2.4).

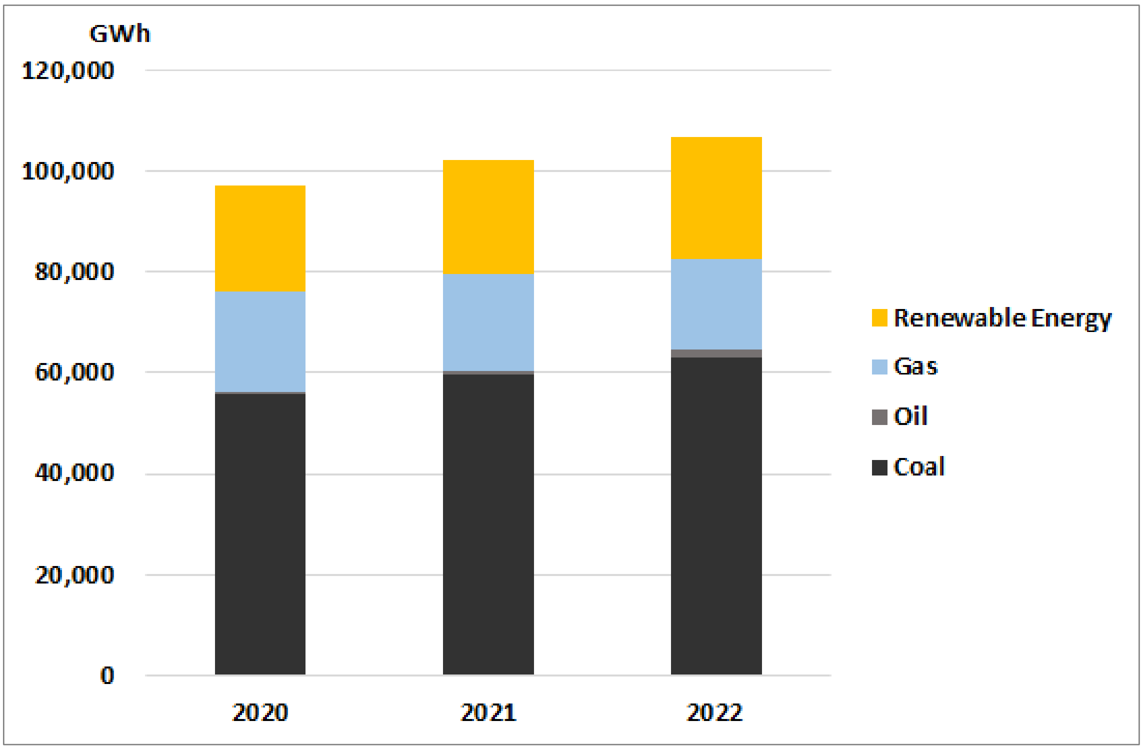
Table 2.4. Primary Energy Consumption in the Philippines

	Mtoe							Shares (%)		
	1990	2000	2010	2020	2030	2040	2050	1990	2020	2050
Total	27	39	42	58	90	116	144	100	100	100
Coal	1.5	4.8	7	18	22	27	29	5.5	30	20.0
Oil	10	16	14	16	32	45	59	36	28	41
Natural gas	-	-	3	3	7	13	21	-	6	15
Nuclear	-	-	-	-	-	-	-	-	-	-
Hydro	0.5	0.7	0.7	0.6	1.0	1.1	1.1	1.9	1.1	0.8
Geothermal	4.7	10.0	8.5	9.2	17.0	19.0	21.0	17.0	16.0	15.0
Solar, wind, etc.	-	-	-	0.2	0.7	1.5	2.6	-	0.4	1.8
Biomass and waste	10	8	9	11	10	10	10	39	18	7
Hydrogen	-	-	-	-	-	-	-	-	-	-

Source: IEEJ (2022).

Output from coal-fired power plants increased by 13% between 2020 and 2022. Coal imports to the Philippines grew substantially due to declining domestic gas production. A decline in the domestic Malampaya gas field production contributed to decreased gas-fired power generation. Renewables generation also rose by 14% during the same period. Hydropower contributed most of the increase (Figures 2.9 and 2.10).

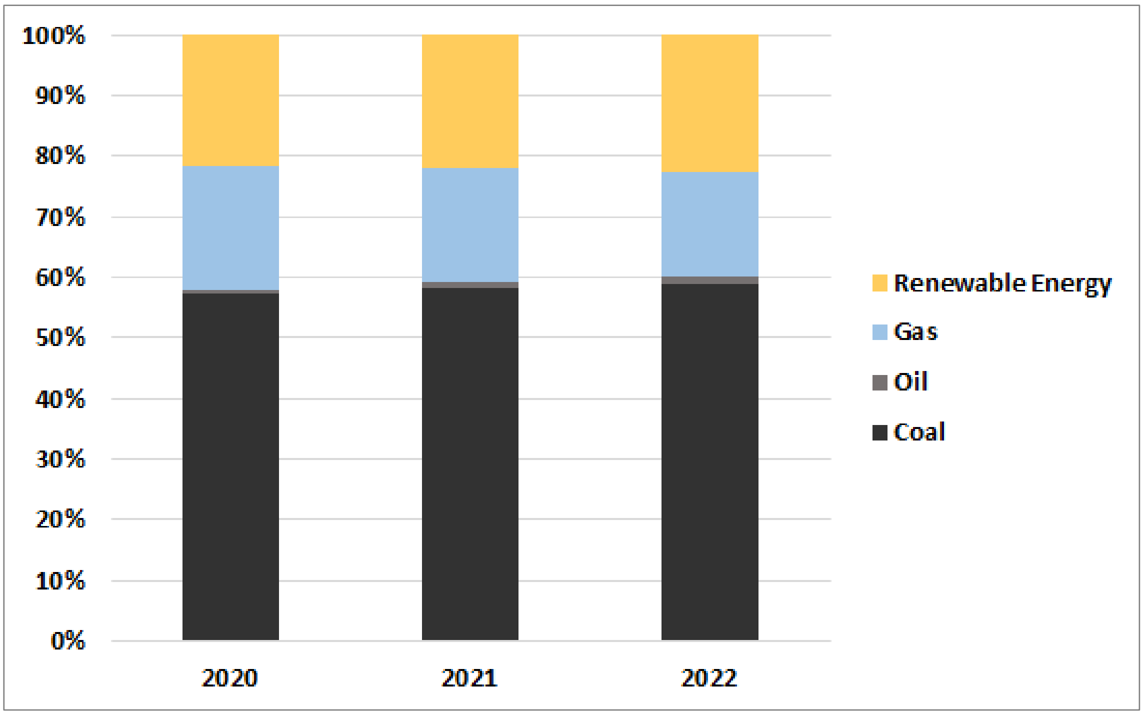
Figure 2.9. Annual Power Generation by Fuel Type, 2020–2022 (GWh)



Source: Based on data from Ember.

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

Figure 2.10. 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 2020–2040 sets domestic natural gas development targets to increase domestic reserves to 5.87 Tcf and production to 3.5 Tcf by 2040. The government plans to import LNG, as the country's only existing Malampaya gas field is expected to be depleted in 2027.

In October 2020, New Fortress Energy of the US signed an MOU with the Philippine National Oil Company to develop infrastructure for power and natural gas in the country (New Fortress Energy, 2020) The two companies will conduct a potential study on the development of LNG and power infrastructure in the Philippines and consider the establishment of an LNG value chain.

In December 2021, the government announced its intention to invest ₱502 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).

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 of Manila, and Excelerate Energy would each begin commercial operations progressively after 2023. Shell Energy Philippines announced it will invest $66 million to build an LNG import terminal, with construction to commence in 2024 (Offshore Technology, 2022).

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	2023 (Under Construction)	
Batangas (FSRU)	3.8	162,000	2023 (Under Construction)	First Gen 80%, Tokyo Gas 20% （FSRU Owner：BW Gas）
	3.0	N.A.	2026 (Under Planning)	Vires Energy Corporation
	3.8	170,000	Under Planning	Shell
Pagbilao LNG	2.2	130,000	2023 (Under Construction)	Energy World Corporation
Mariveles LNG	0.2-0.4	N.A.	2024 (Under Construction)	Samat LNG
Cebu LNG (FSRU)	N.A.	N.A.	Under Planning	Phinma Petroleum and Geothermal (PPG)
Ilijan LNG (FSRU)	N.A.	N.A.	Under Planning	San Miguel Corporation (SMC)
Luzon LNG (FSRU)	N.A.	150,000	Under Planning	Excelerate Energy

FSU = floating storage unit.
Source: IEEJ Analysis.

5. Viet Nam

5.1.1. Economy and Energy Demand Outlook

The IEEJ Outlook 2023 forecasts Viet Nam's primary energy consumption to increase by an average of 3.1% per year, based on an assumed economic growth rate (2015 prices) of 5.3% annually from 2020 to 2050. The energy mix in 2050 will comprise 45% coal, 25% oil, 14% natural gas, 3.5 nuclear, 4.5% hydro, 5.6% biomass and waste, 2.2% solar, wind, etc. (Table 2.6).

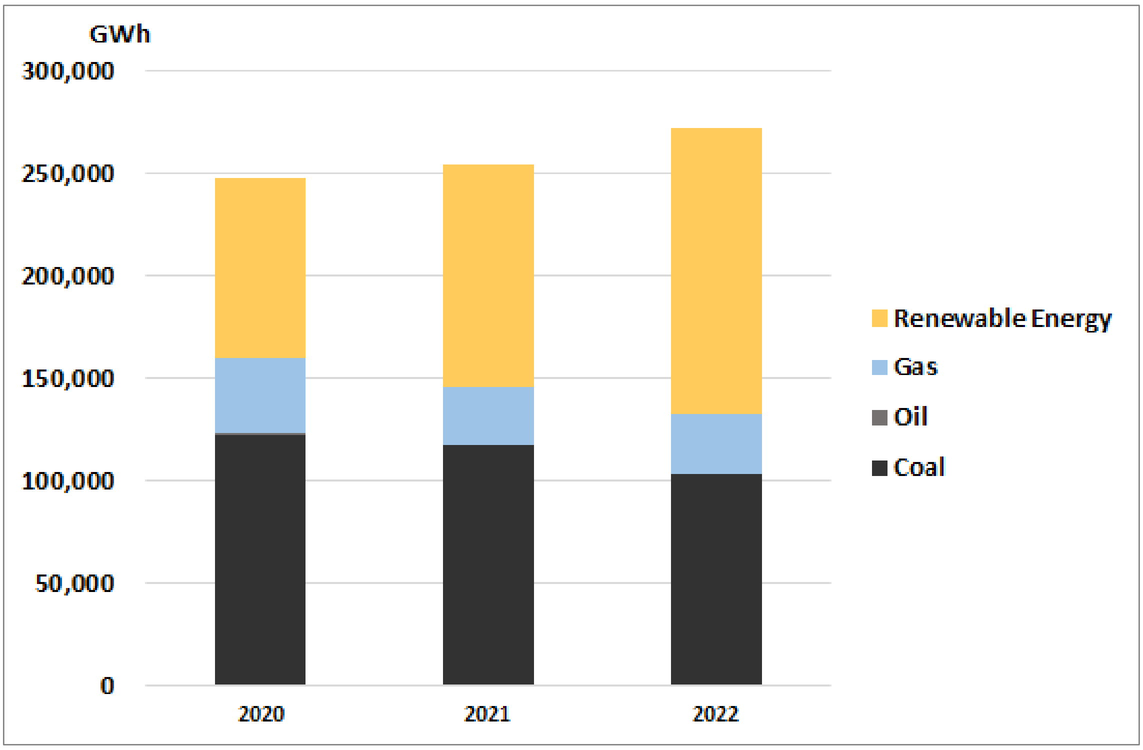
Table 2.6. Primary Energy Consumption in Viet Nam

	Mtoe							Shares (%)		
	1990	2000	2010	2020	2030	2040	2050	1990	2020	2050
Total	18	29	59	97	147	195	245	100	100	100
Coal	2.2	4.4	15	51	70	91	111	12.0	52	45.0
Oil	3	8	18	24	40	50	61	15	25	25
Natural gas	-	1	8	7	16	23	34	-	8	14
Nuclear	-	-	-	-	-	4.2	8.6	-	-	3.5
Hydro	0.5	1.3	2.4	6.3	9.3	10.0	11.0	2.6	6.4	4.5
Geothermal	-	-	-	-	-	-	-	-	-	-
Solar, wind, etc.	-	-	-	0.9	2.5	3.6	5.3	-	0.9	2.2
Biomass and waste	12	14	15	8	9	11	14	70	8	6
Hydrogen	-	-	-	-	-	-	-	-	-	-

Source: IEEJ (2022).

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 2.11 and 2.12).

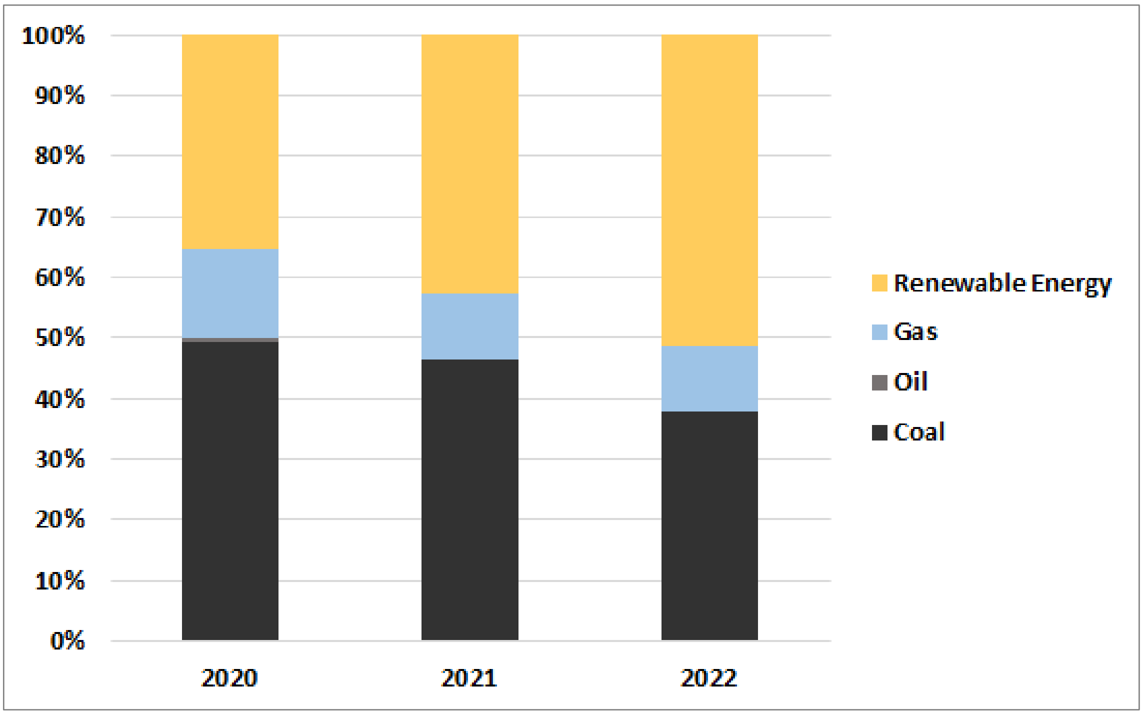
Figure 2.11. Annual Power Generation by Fuel Type, 2020–2022 (GWh)



Source: Based on data from Ember.

For the first time, over half of the total power generation in Viet Nam came from renewables in 2022 (Figure 2.12).

Figure 2.12. Share of Annual Power Generation by Fuel Type, 2020–2022 (%)

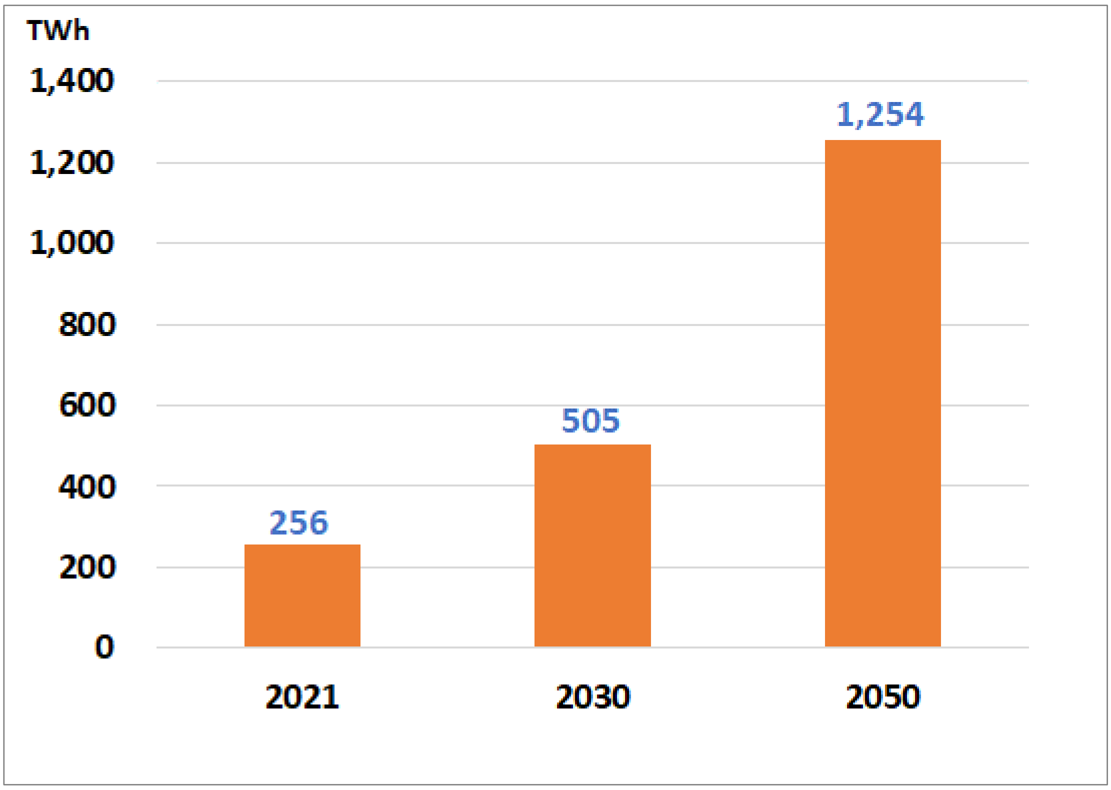


Source: Based on data from Ember.

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. PDP8 sets out the roadmap for electricity vision, representing Viet Nam's commitment towards decarbonisation. PDP8 assumes that the average annual GDP will grow 7% in 2021–2030 (Figure 2.13). 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 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 2.13. Total Electricity Generation in Viet Nam

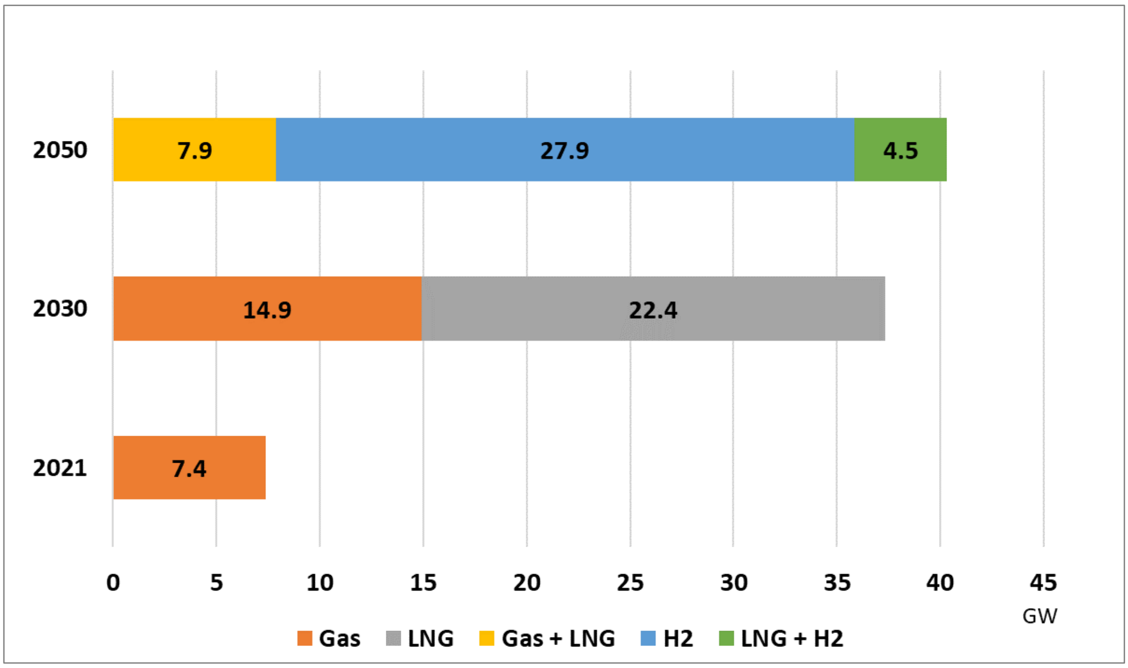


Source: Based on data from APERC.

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 for LNG-to-power plants by 2050. As for gas power, the installed capacity will increase to 37.3 GW by 2030 from 7.4 GW in 2021, the installed capacity is expected to reach 40.3 GW by 2035, only 7.9 GW up by 2050 (Figure 2.14). 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 2.14. Electricity Generated from Gas in Viet Nam



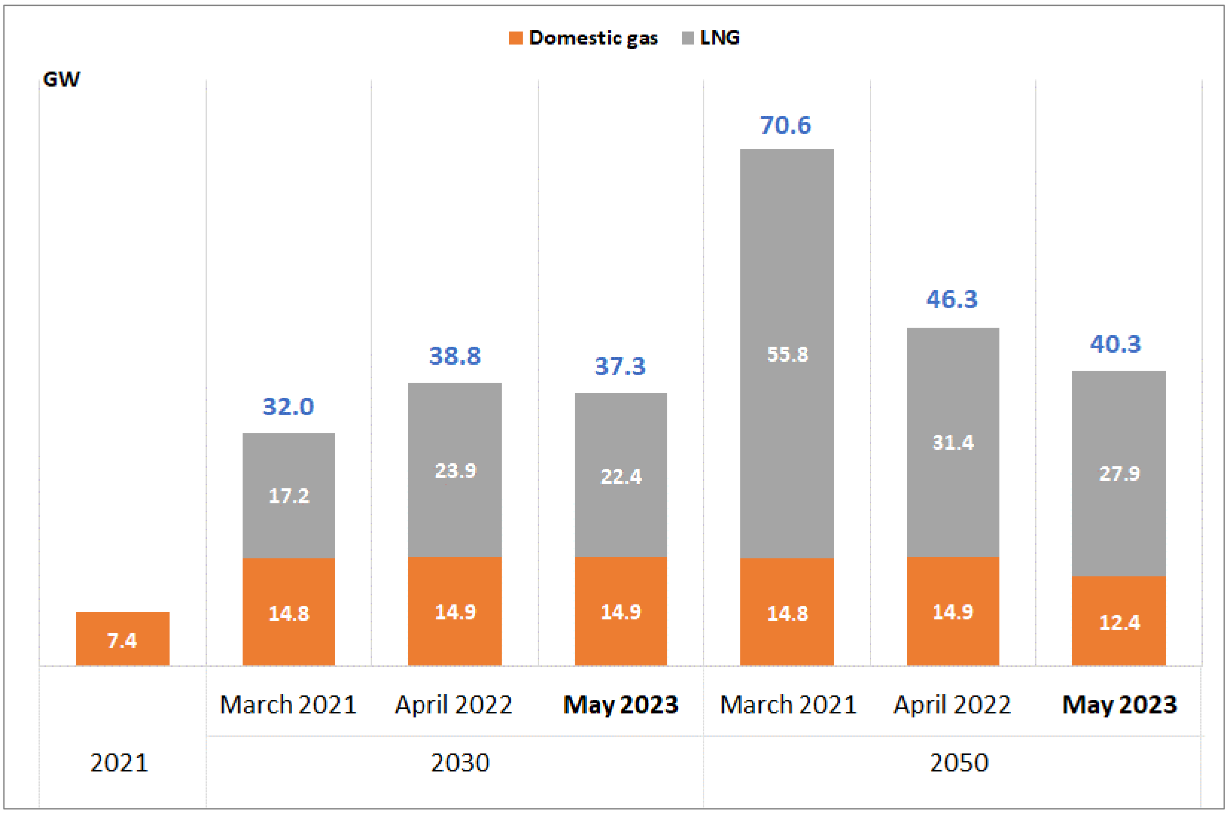
Source: Based on data from APERC.

The extremely high and volatile LNG prices have affected Viet Nam's future LNG usage plan. In 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 2.15).

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, gas power is cleaner than coal power in terms of CO_2 emission, but still emits CO_2. Therefore, the Viet Nam government plans to develop more renewable energy.

The high price also delayed LNG power development. For example, one of the first LNG terminals in Viet Nam was completed in 2022, but the commissioning was postponed due to the absence of LNG. Another thing, the high price makes it difficult to finalise the power purchase agreement (PPA) between investors and the state utility. If the PPA development and the infrastructure construction are delayed, the LNG-to-power process will take longer.

Figure 2.15. Assumed Amount of Gas Needed for Power Generation



Source: Based on data from APERC.

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, and the country would rely on imports for 1–4 Bcm/y in 2021–2025. According to the country's master plan, gas-fired power generation is expected to be 15,000 MW in 2025, accounting for 19% of total power generation, then increase to 19,000 MW in 2030, requiring 22 Bcm of natural gas, half of which is 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. 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 a national energy plan approved by Prime Minister Pham Minh Chinh in May. To help offset the shift, Ha Noi aims for LNG to account for around 15% of its current power generation by 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	2023 (Under Planning)	PetroVietnam Gas
Hai Linh	2.0-3.0	657,000	N.A.	Hai Linh
Bạc Liêu (FSRU)	3.0	N.A.	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	N.A.	2027-2030 (Under Planning)	
(Phase 3)	3.0	N.A.	2031-2035 (Under Planning)	
Long Son	3.5	N.A.	2025 (Under Planning)	GENCO3
Ca Mau	1.0	N.A.	2026 (Under Planning)	PV Power
Thai Binh (FSRU)	0.2-0.5	N.A.	2026-2030 (Under Planning)	N.A.
Ninh Thuan	6.0	N.A.	Under Planning	Gulf Energy
Thua Thien Chan May LNG	2.9	N.A.	2024 (Under Planning)	Chan May LNG
Cai Mep Ha	9.0	800,000	2023 (Under Planning)	T&T Group, Gen X Energy
(Phase 2)			2026 (Under Planning)	
(Phase 3)			2030 (Under Planning)	
Tien Lang (FSRU)	6.0	N.A.	2027 (Under Planning)	Exxon Mobil, JERA
(Phase 2) (FSU)		N.A.	2030 (Under Planning)	
Cat Hai	N.A.	200,000	2025 (Under Planning)	Vingroup
Cam Pha	N.A.	200,000	2027 (Under Planning)	Quang Ninh LNG Power (PV Power, Colavi, Marubeni, Tokyo Gas)
Mui Ke Ga (FSRU)	N.A.	N.A.	2025 (Under Planning)	Energy Capital Vietnam (ECV), Gunvor
Long An	N.A.	N.A.	2025 (Under Planning)	VinaCapital, GS Energy

Receiving Terminal	Capacity (Mtpa)	Storage (kl)	Operation Start	Stakeholders
Nam Dinh	0.7	50,000	2025 (Under Planning)	JAPEX, ITECO
Hai Lang	1.5	N.A.	2027 (Under Construction)	T&T Group, KOGAS, KOSPO, Hanwha Energy

FSU = floating storage unit.
Source: IEEJ Analysis.

Chapter 3
Factors Causing Price Volatility

1. Multiple Factors Coincided to Amplify Volatility

Generally, prices are determined by market relationships, mainly supply and demand, under various circumstances. In most cases, LNG production requires an extended lead time. If there is an imbalance between supply and demand, or without supply enough to meet fluctuating demand, there will be a product shortage, and prices will rise. In brief, the price volatility of the last few years resulted from the inability of supply increase to meet a rapid demand increase over a short period.

The following concurrent multiple factors in the past couple of years caused the recent round of extreme volatility of gas prices:

- ✓ Long-term structural increases in gas demand, based on economic growth and resulting needs for clean and high-heating value energy sources; and persisting lack of expansion of long-term supply capacity
  - ➢ Upstream and LNG projects have historically required long lead times and massive investment
  - ➢ Global shortages of funding sources to take care of the enormous financing needs for decarbonisation
  - ➢ Decarbonisation uncertainty has made companies prefer short-term commodity procurement to upstream investment, which would bind capital for longer periods.
  - ➢ Tendencies in society to hamper investment in fossil fuel development, including potential legislations and regulations to restrict those activities, as well as movements in the society to oppose fossil fuel development
  - ➢ Europe's historical dependence on relatively less expensive Russian pipeline gas, which had discouraged investment in LNG production and upstream development
  - ➢ Buyers' hesitations to commit large volumes of off-takings from one LNG project, leading to slower progress of LNG production development, delaying FIDs;
  - ➢ Increasing shares of spot and short-term transactions of LNG, which at least until today have led to higher volatility of spot LNG prices
- ✓ Short-term sudden increases in gas demand leading to a massive shift to LNG in Europe, which is willing to pay extra money to procure additional volumes to phase out Russian pipeline gas supply rapidly;
- ✓ Chinese gas demand increased after the pandemic restriction; and
- ✓ Seasonal demand fluctuations and those caused by drought and severe winter; planned and unplanned outages and unexpected troubles at LNG production plants;

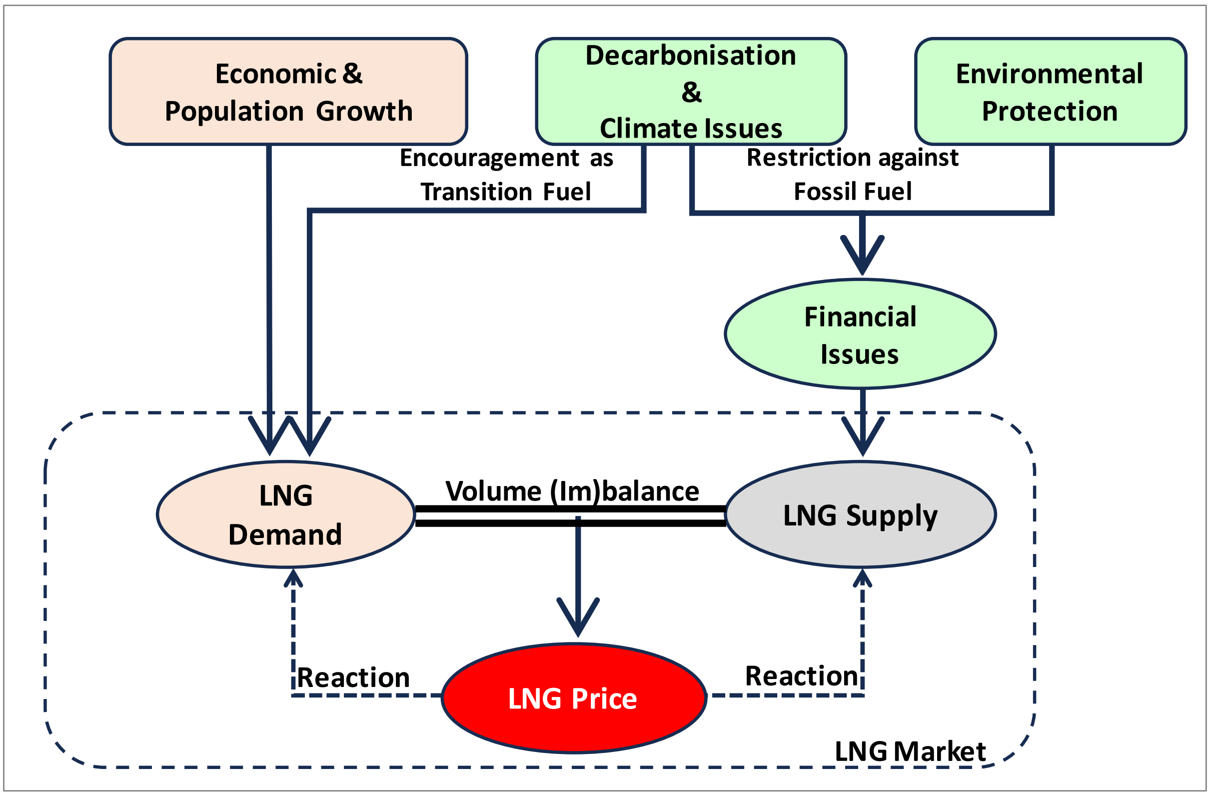
The following sections discuss the factors mentioned above regarding the demand and supply sides and some key factors causing major price fluctuations. Table 3.1 and Figure 3.1 briefly show some of those factors and their interrelationship.

Table 3.1. Examples of Factors Causing Price Volatility

	Short-term Issues	Long-term Issues
Supply issues	Declining Russian piped gas supply, Russian LNG supply maintenance Feed gas shortage issues in LNG production at some projects Unplanned outages at some LNG projects New projects ramping up in the next 1, 2 years	Additional projects in North America Maintain stability and enable expansion of Australian LNG production Realization of LNG projects in Africa LNG-related policies in producing countries
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 thanks to efforts or demand destruction by higher prices) Demand fluctuation in emerging price-sensitive markets	Transition scenarios changing demand outlooks significantly Demand centers shifting to developing economies Preference for shorter long-term contracts
Price	Increasingly greater fluctuation of prices due to increasing volatility and increasing gas-on-gas pricing	Changing pricing arrangements in long-term contracts
Climate	Greater needs to enhance MRV in the LNG value chain Short-term emission reduction measures (recovery of wasted)	Clearer standards of transition-proof LNG projects
Financial	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

MRV = measurement, reporting, and validation.
Source: IEEJ Analysis.

Figure 3.1. Interrelationship amongst Factors Causing Price Volatility



Source: IEEJ Analysis.

2. Demand Side

2.1. Outline of Demand Side

In the long run, natural gas demand is expected to continue increasing, especially in developing countries, along with 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.)

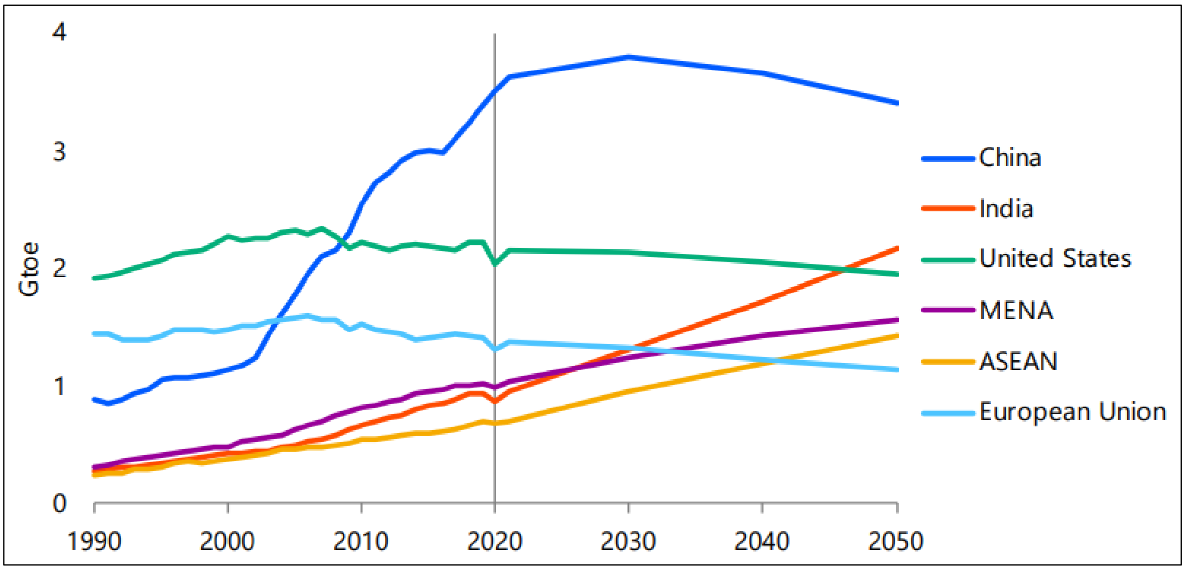
Short-term or sudden changes in circumstances may also significantly impact demand trends, such as Europe's rapid phase-out of dependence on Russian resources, China's demand recovery caused by ending the Zero-COVID policy, and expected or unexpected seasonal demand fluctuations like drought, severe winter, etc.

[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 emission targets will rely on the transition fuel from heavily dependent on fossil fuel for power generation to a clean energy system, LNG. A careful look at affordability, accessibility, and energy security is needed.

The IEEJ Outlook 2023 forecasts primary energy consumption in the ASEAN region to increase at an annual rate of 2.5% between 2020 and 2050 while GDP continues to grow at 3.4% per annum (Figure 3.2).

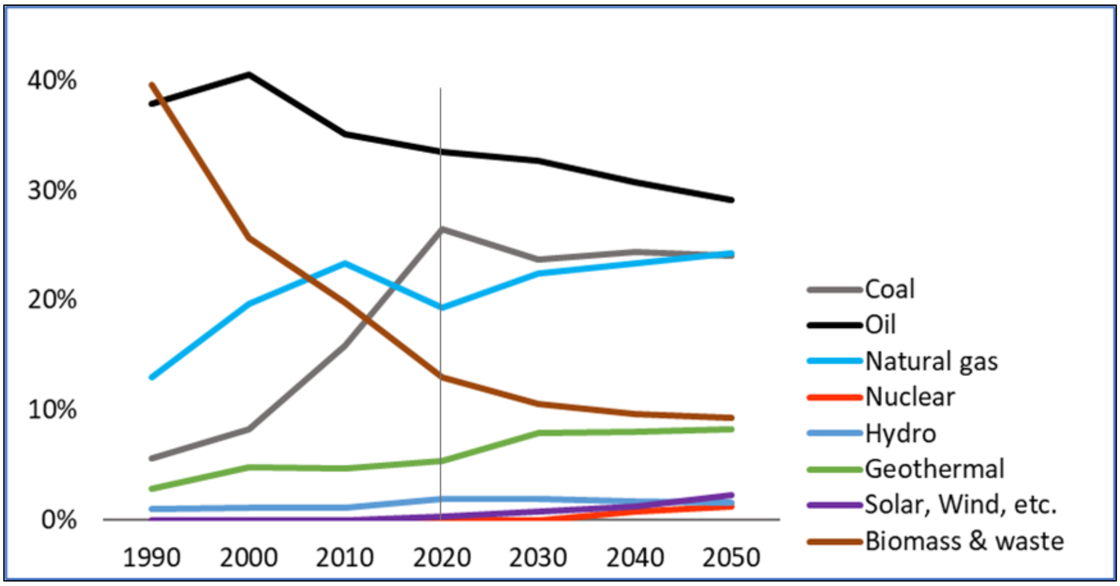
Figure 3.2. Primary Energy Consumption in Selected Countries and Regions



Source: IEEJ (2022).

While energy saving and increase in consumption and supply of renewable energy will progress, demand for natural gas will continue to rise as it is the lowest carbon of any other fossil fuel and will be increasingly adopted in the context 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 IEEJ Energy Outlook 2023, in the ASEAN region, despite an expansion of renewables, the share of natural gas in the energy mix is expected to expand from 19% in 2020 to 24% in 2050 (Figure 3.3).

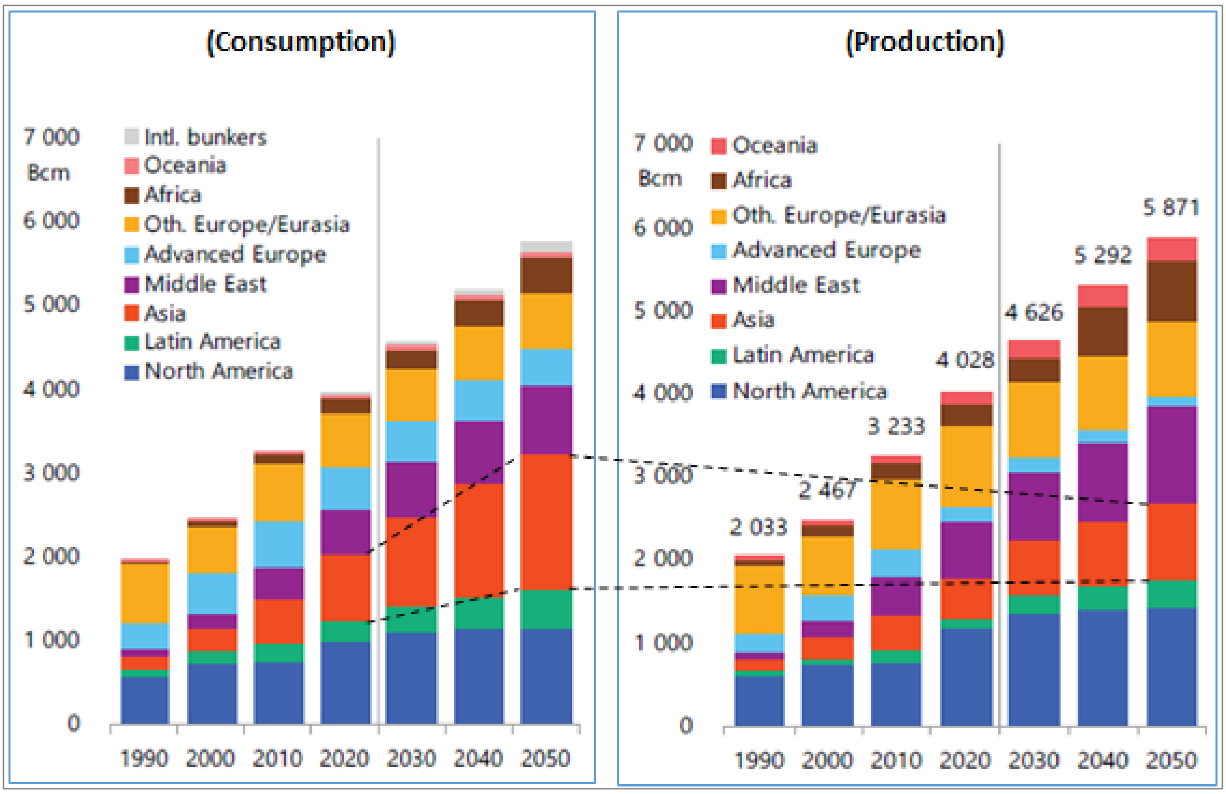
Figure 3.3. Primary Energy Consumption Mix (ASEAN)



Source: IEEJ (2022).

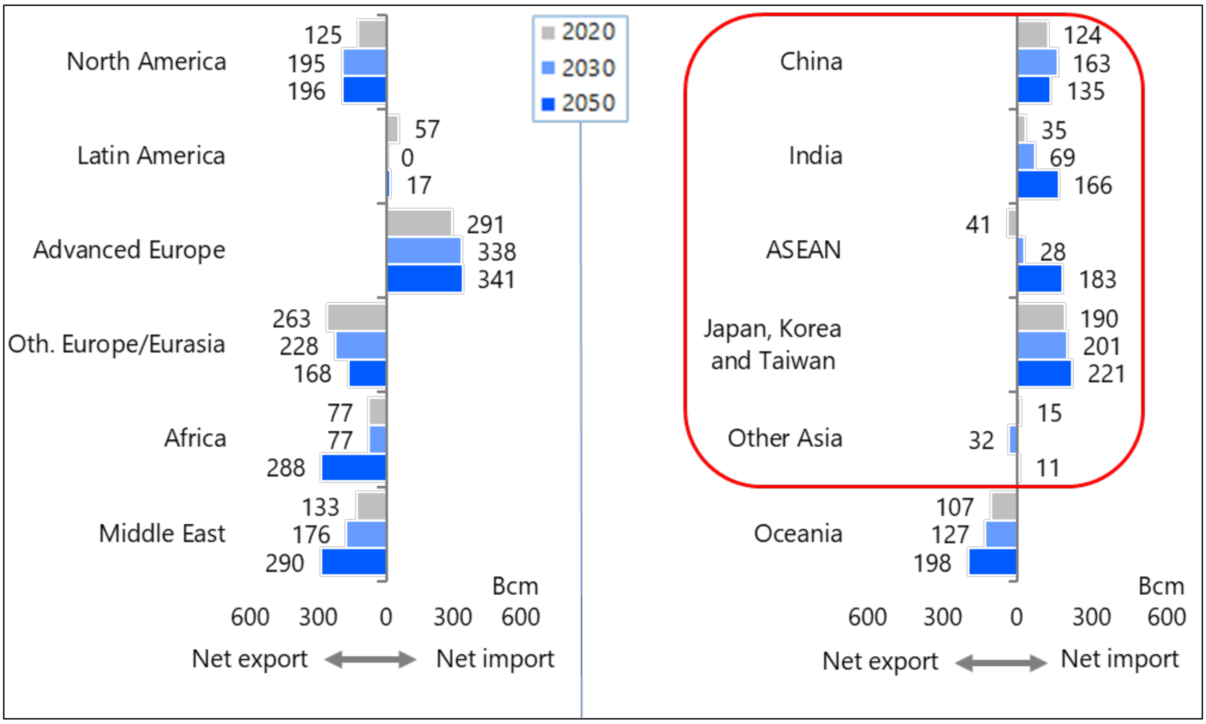
Asian LNG consumption will increase from 273 Mt in 2021 to 551 Mt in 2050. However, as shown in Figure 3.4, LNG production in the region will grow relatively smaller. Therefore, LNG imports will be needed to help cover the shortfall in natural gas supply. Figure 3.5 shows that Asia's imports could increase significantly. The import dependency will rise from around 30% today to nearly 50% by 2050. It is, therefore, certain that ASEAN should maintain steady investment in upstream and 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 members, even existing LNG-producing and -exporting countries, have started and will start importing LNG.

Figure 3.4. Natural Gas Consumption and Production



Source: IEEJ (2022).

Figure 3.5. Net Exports and Imports of Natural Gas



Source: IEEJ (2022).

[Recent Situation in LNG Demand]

Global LNG import increased from 372.3 Mt in 2021 to 394.4 Mt in 2022, and is expected to reach 427 Mt in 2023 (up by 8.3% from the previous year) if there are no major troubles. However, the export growth is limited, so IEEJ prospects 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 US production increase 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, and LNG trade showed a rapid expansion mainly due to the strong demand of the Northeast Asian country. 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 demand volumes expanded by 5%, mostly from US product gains. Since Europe needs additional LNG supply to make up for Russian gas supply through pipelines, the LNG imports into European countries increased by 46.4 Mt (61.8% year-on-year), and its share in the global market reached 30.8% in 2022 from 20.2% in 2021, which was covered mainly by the US production growth. Due to significantly higher spot LNG prices, Asian countries needed to decrease 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 the first half of 2023, global LNG trade fluctuated flatter than a 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 milder winter and structural demand destructions. ASEAN importers increased LNG imports significantly, with the Philippines and Viet Nam additions as new LNG importing markets. China returned to positive growth of LNG imports and regained the position of the largest importer of LNG during the period, although still shy of the record import in the same period of 2021.

Figure 3.6. LNG Imports and Exports in the First Half of the Year

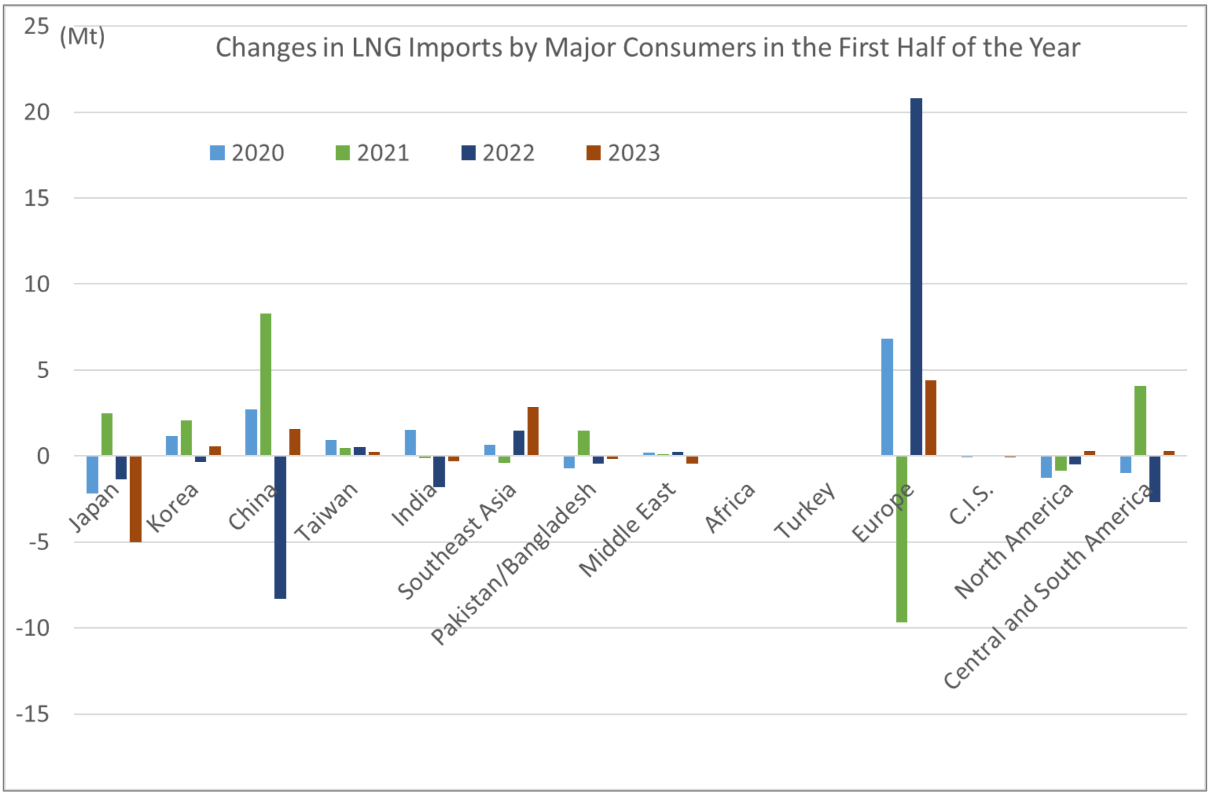
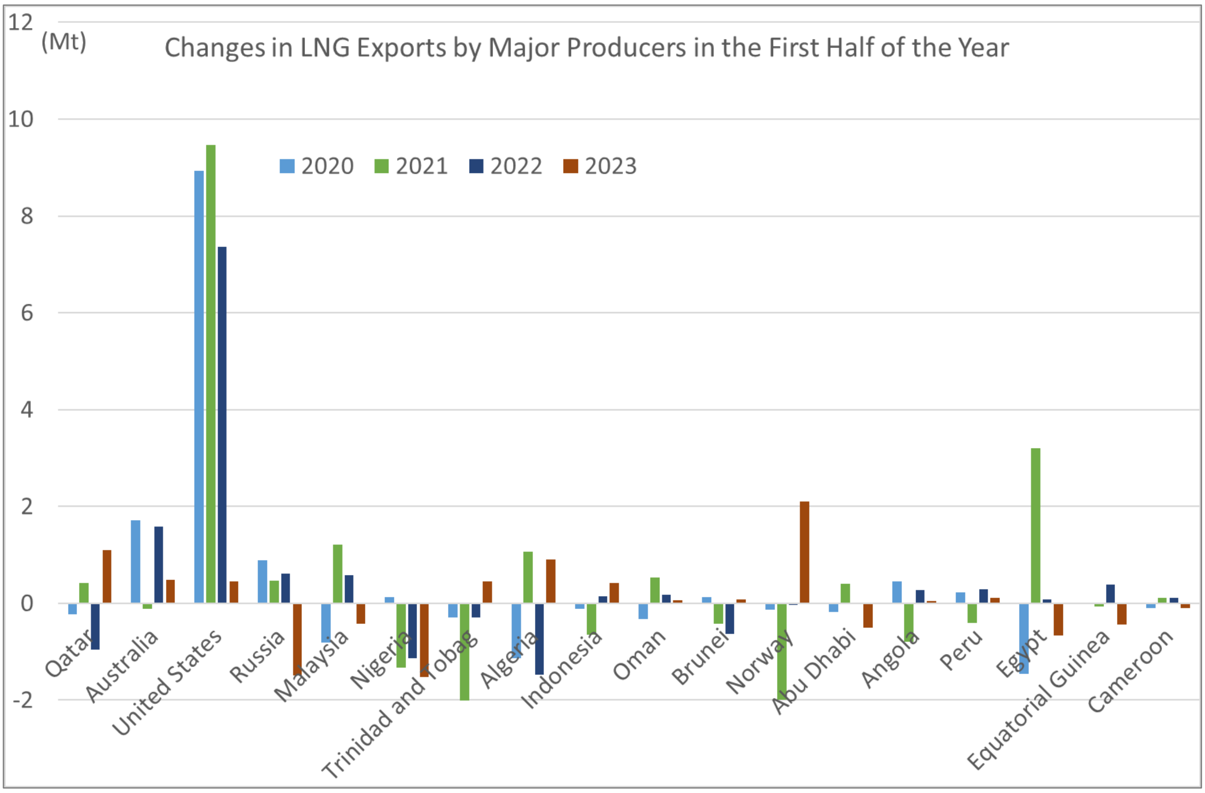


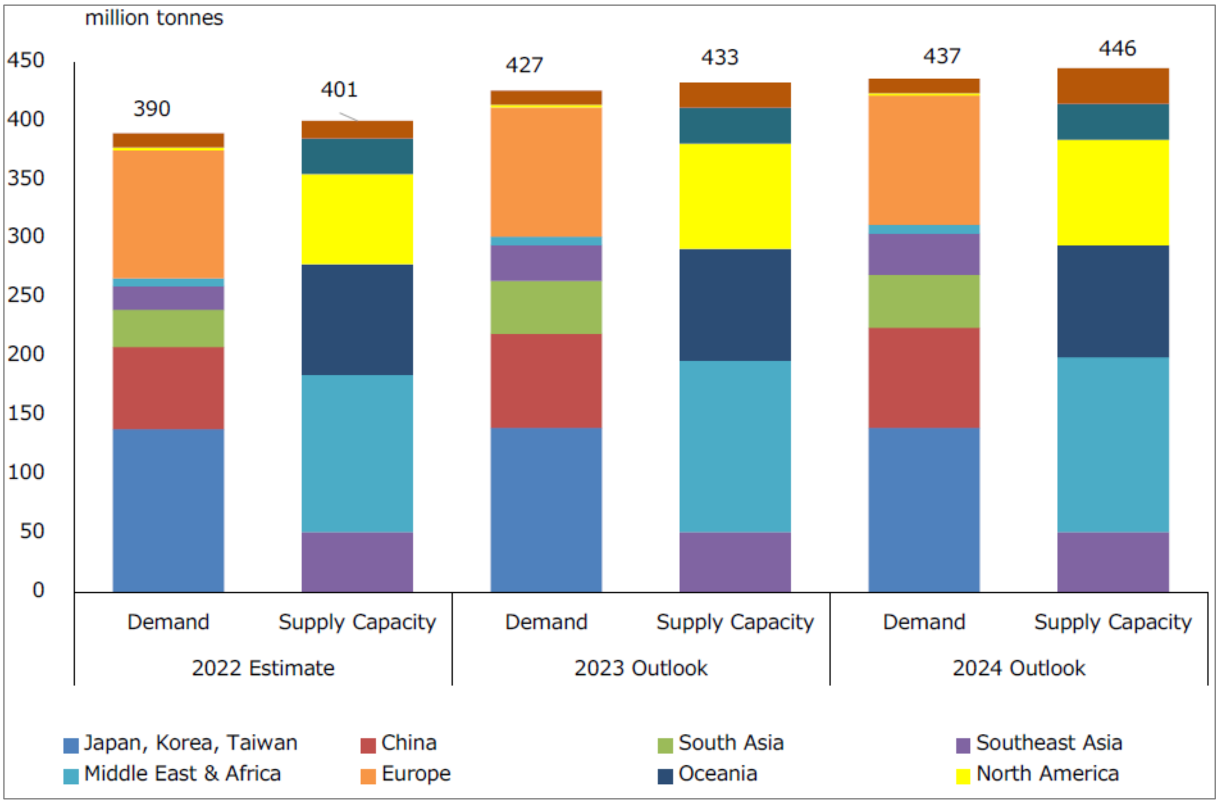
Figure 3.6. ***Continued***



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 3.7) The global LNG market is expected to grow 9% in 2023, assuming no facility and other troubles. 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 3.7. Gas Production and Imports (PJ)



Source: IEEJ (2023).

3.2.1 Europe: Suddenly Emerging as a Powerful Buyer of LNG

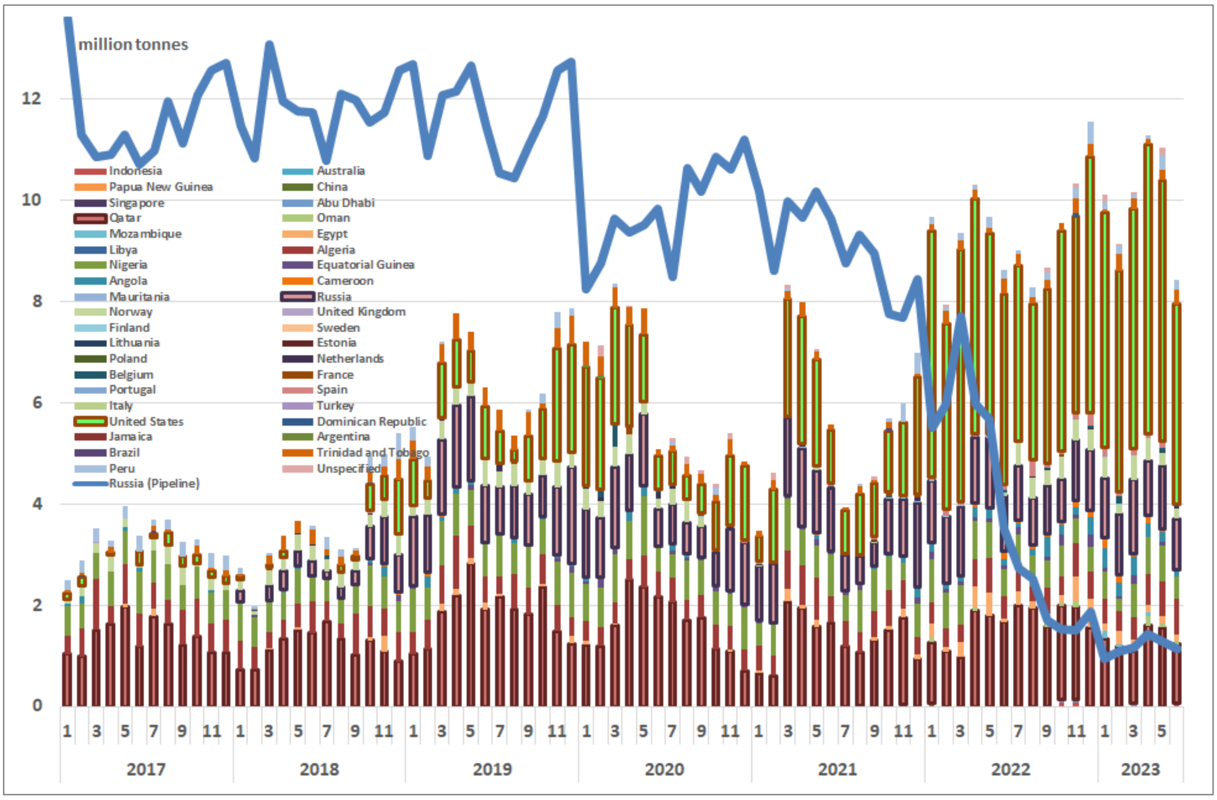
Since the Russian invasion of Ukraine in February 2022, Europe has emerged as an enormous LNG buyer with strong purchasing power. The purchaser is expected to stay for at least several years, but it may be phased out by around 2050 with the progress of its decarbonisation efforts.

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 Russo–Ukrainian 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. Nord Stream 2 is not operational because the German government withheld its opening permission in February 2022. Russian pipeline gas supply to Europe will decrease further in 2023. As a result, LNG offtake from other parts of the world by Europe has been increasing, mainly from the US.

Unless there are major changes in Russia's 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 3.8. Monthly Imports of LNG & Russian Pipeline Gas to Europe

(Europe = EU + UK)



Source: Based on Cedigaz and Trade Statistics of Various Countries.

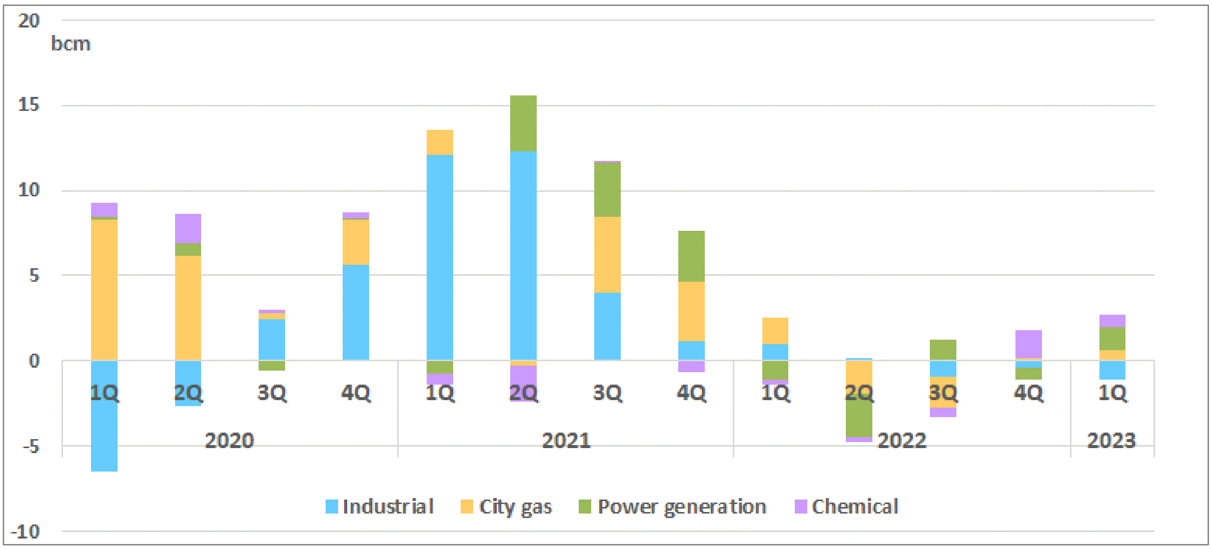
Still, Europe has been importing LNG from Russia. Russian LNG has not been subject to sanctions. The country now has two operating LNG export facilities – Yamal LNG, led by Novatek, and Sakhalin 2 LNG, led by Gazprom. France, Spain, and other EU members have been importing LNG from the Yamal project as part of their portfolio contracts. EU member countries imported 13.6 Mt of Russian LNG in 2022, slightly increasing from 2021.

2.2. China: Giant Shaker of the LNG Market

China's demand trend can easily shake the global LNG market. In 2021, China surpassed Japan in LNG imports, becoming the world's largest LNG importer. 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. China has a huge population and economy, and government policies greatly influence its energy mix, so the impact on the global supply–demand situation and its amplitude is enormous.

China’s natural gas consumption increased by 4.1% year-on-year during the first 4 months of 2023, especially a 7.1% increase in April. In 2022, half of the decrease in gas consumption came from the power generation sector, although the share of power generation in gas consumption was relatively low at 17%. In 1Q 2023, natural gas consumption increased in the city-gas and power generation sectors while industrial use declined (Figure 3.9).

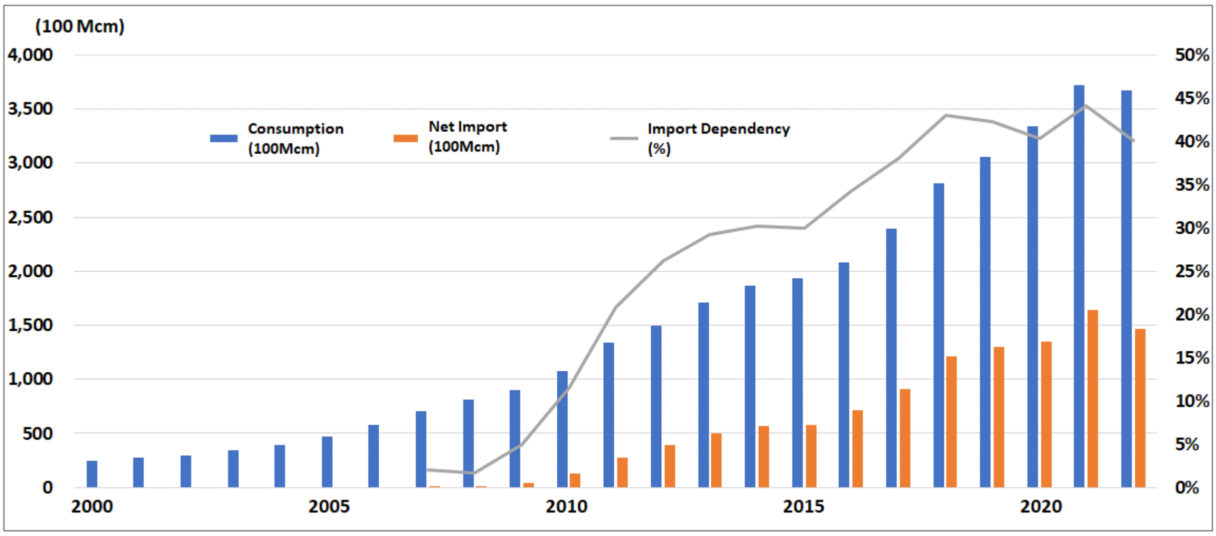
Figure 3.9. China's Natural Gas Demand by Sector



Source: Based on data of the National Statistics Bureau of China.

Between 2010 and 2020, natural gas's share doubled, and consumption increased more than three times. Until 2021, the LNG import increased by an annual average rate of 14%. The net imports account for more than 40% of the total gas consumption (Figure 3.10).

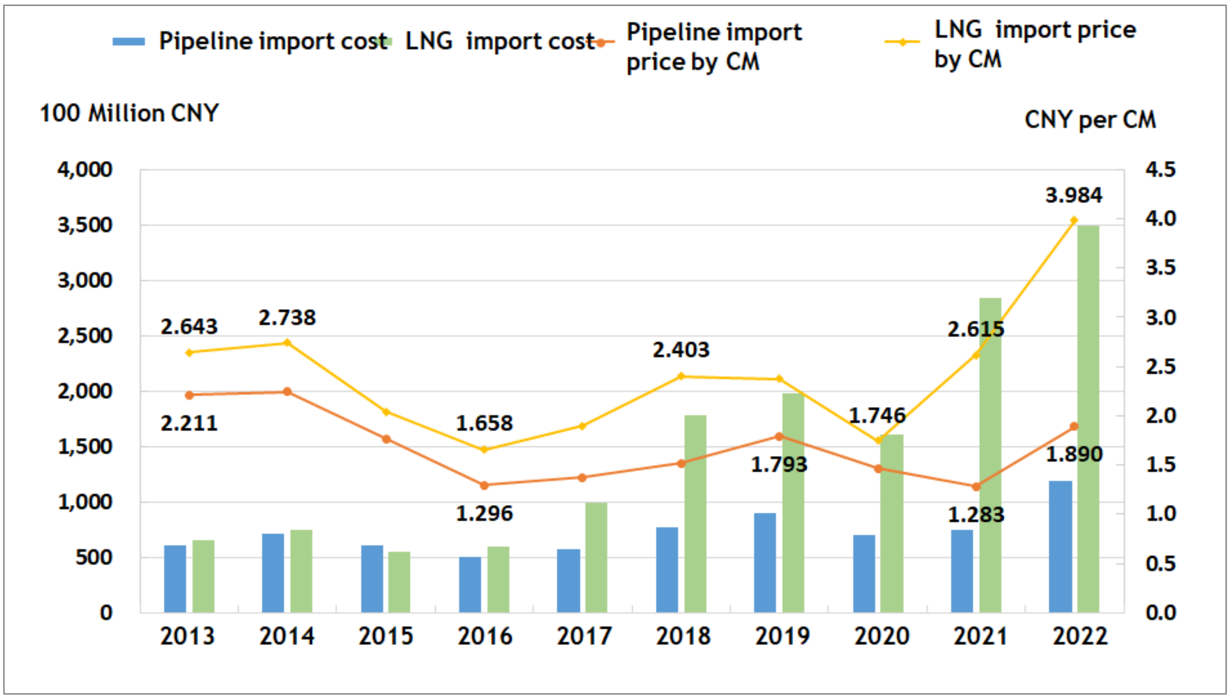
Figure 3.10. Gas Consumption and Import in China, 2000–2022



Source: Based on data from the Institute of Energy, Peking University.

Total imports more than doubled in 2020–2022, although LNG imports decreased due to significant price increases.

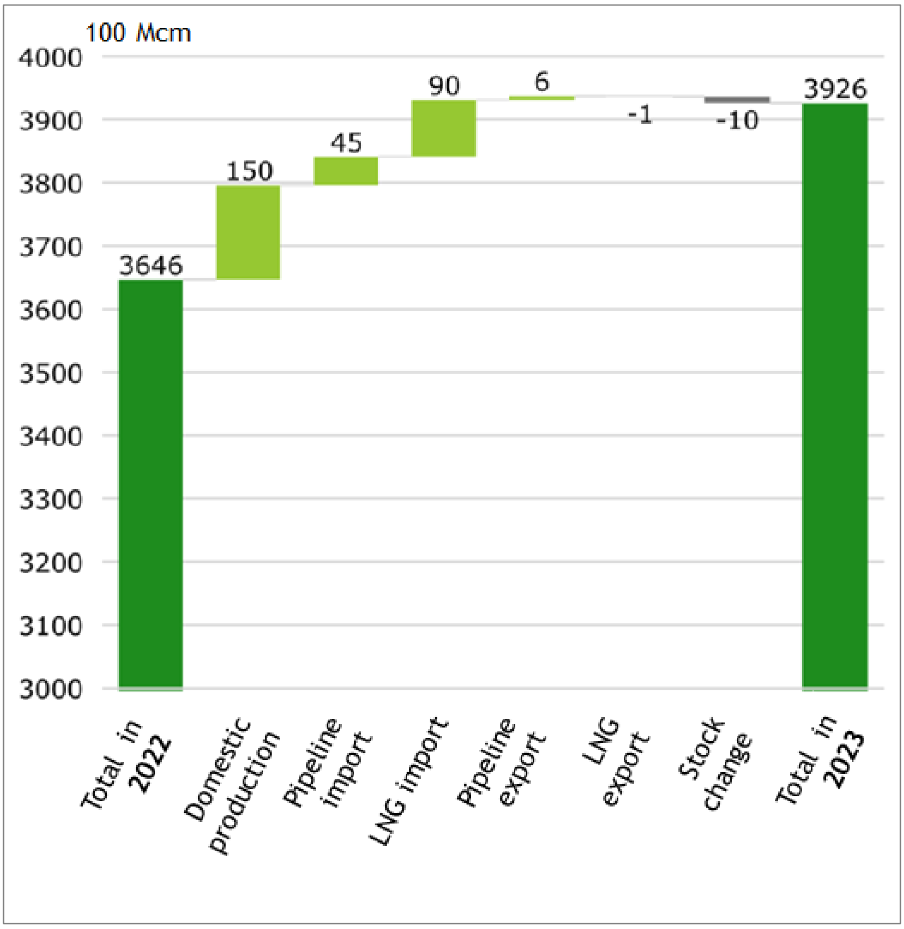
Figure 3.11. Gas Import Price and Cost in China



Source: Based on data from the Institute of Energy, Peking University.

Figure 3.12 shows gas consumption in China is expected to increase from 364.6 Bcm in 2022 to 392.6 Bcm in 2023 (7.7% year-on-year), according to the Institute of Energy, Peking University. The increase includes 15.0 Bcm of domestic gas production, 4.5 Bcm of imports by pipeline, and 9.0 Bcm of LNG.

Figure 3.12. Gas Consumption Outlook by Sources in China



Source: Based on data from SIA Energy.

China has abundant domestic natural gas production and import capacity through pipelines from Russia and Central Asia. As Russia needs a destination for its natural gas, China will try to use its position as a buyer to purchase pipeline gas more cheaply. Furthermore, thanks 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 3.2).

Table 3.2. Long-term Contracts Made by Chinese Companies (2022–1H 2023)

Date	Project	Counterpart	Volume (Mtpa)	Duration (year)	Delivery	Price	Export Country
2022/03/29	Lake Charles	ENN	1.8	20	FOB	Henry Hub	USA
2022/03/29	Lake Charles	ENN	0.9	20	FOB	Henry Hub	USA
2022/04/01	Mexico Pacific Limited	Guangzhou	2.0	20	N.A.	N.A.	Mexico
2022/04/06	NextDecade Rio Grande	ENN	1.5	20	FOB	Henry Hub	USA
2022/06/05	Lake Charles	China Gas	0.7	25	FOB	Henry Hub	USA
2022/07/05	NextDecade Rio Grande	China Gas	1.0	20	FOB	Henry Hub	USA
2022/07/06	NextDecade Rio Grande	Guangdong Energy	1.0	20	DES	Henry Hub	USA
2022/07/20	Cheniere Corpus Christi Stage III	PetroChina	0.9	25	FOB	Henry Hub	USA
2022/07/20	Cheniere Corpus Christi future trains	PetroChina	0.9	25	FOB	Henry Hub	USA
2022/11/21	QatarEnergy	Sinopec	4.0	27	DES	N.A.	Qatar
2022/11/24	bp	Shenzhen Energy	N.A.	N.A.	N.A.	N.A.	Portfolio
2022/12/27	NextDecade Rio Grande	ENN	0.5	20	FOB	Henry Hub	USA
2023/02/07	Oman LNG	UNIPEC	1.0	4	FOB	N.A.	Oman
2023/02/23	VG Plaquemines	China Gas	1.0	20	FOB	N.A.	USA
2023/02/23	VG CP2	China Gas	1.0	20	FOB	N.A.	USA
2023/06/20	QatarEnergy	CNPC	4.0	27	DES	N.A.	Qatar
2023/06/26	Cheniere Sabine Pass Expansion	ENN	1.8	20	FOB	N.A.	USA

DES = delivery ex ship, FOB = free on board.
Source: IEEJ Analysis.

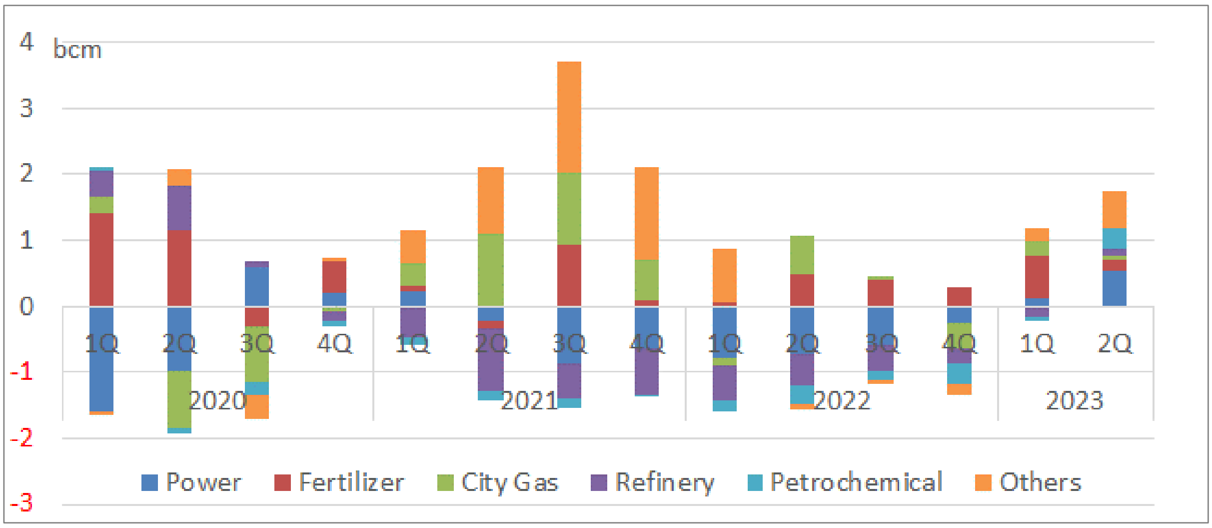
2.4. India and South Asia

South Asia, including India, Bangladesh, and Pakistan, slashed LNG purchases by 16% 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 which a decline in gas use for power generation was notable at –24% or –2.4 Bcm. In 2022, 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 (Figure 3.13).

Figure 3.13. India's Gas Demand by Sector (Year-on-year Changes)



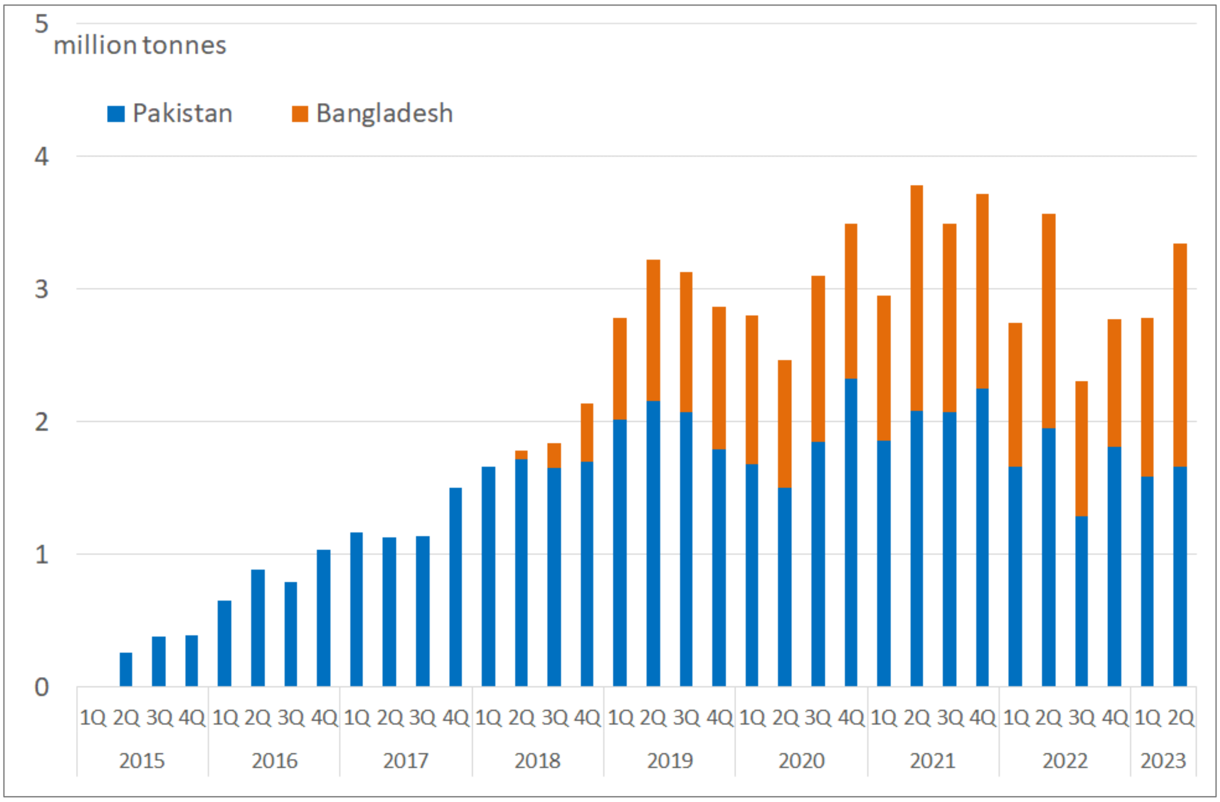
Source: Based on data from the Ministry of Petroleum and Natural Gas of India.

Bangladesh and Pakistan

Regarding LNG procurement, there has been a relatively sharp contrast between Southeast and South Asian countries – Bangladesh and Pakistan. While ASEAN members increased LNG imports by 2.5 Mt in 2022, Bangladesh and Pakistan lost almost the same amount, with signs of more difficulties in procurement. The latter nations 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 impact relatively weak economies in Asia.

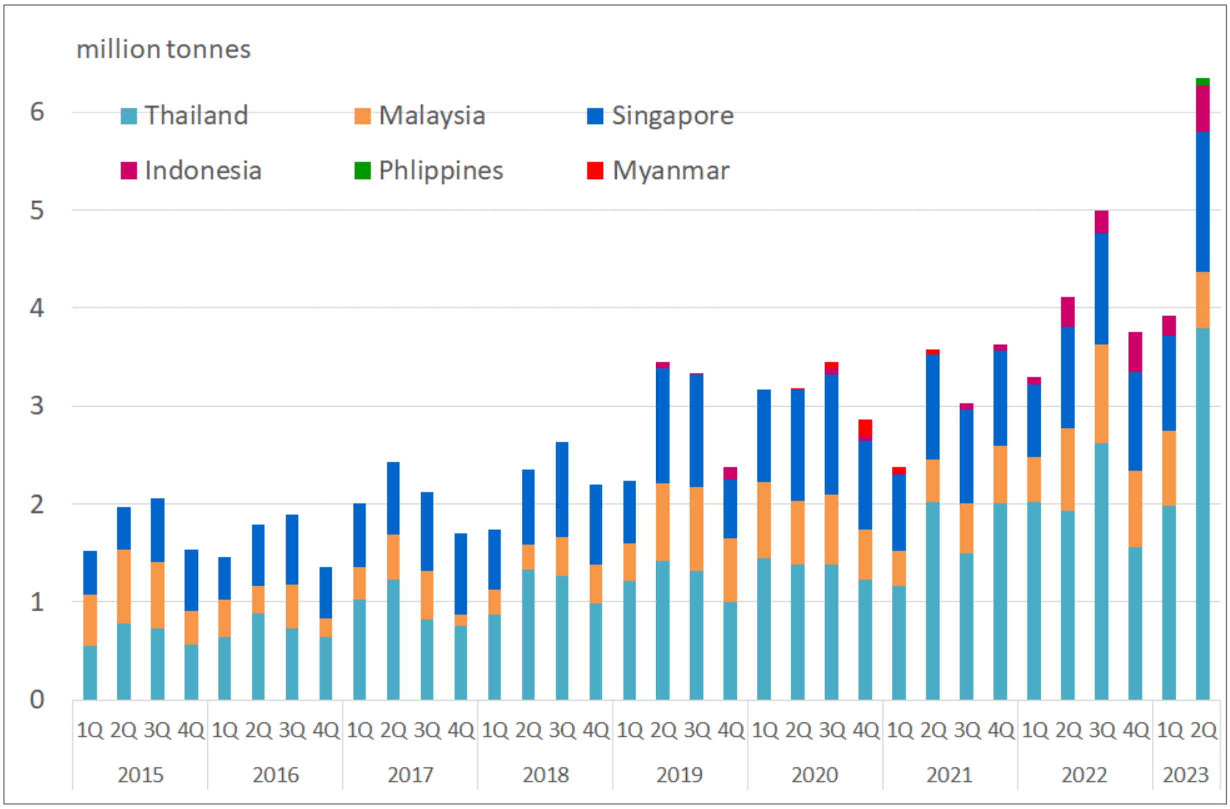
If a country has a lower credit rating, it is difficult for an LNG importer in such a country to secure a long-term LNG purchase contract and secure LNG cargo in the spot market.

Figure 3.14. LNG Imports by Bangladesh and Pakistan



Source: Based on Cedigaz and trade statistics of various countries.

Figure 3.15. LNG Imports by Southeast Asian Countries



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 over contracted capacities during normal times nor to expand supply capacity in a short period. Extended lead time, significant capital investment, and payback are required before an LNG production site can become 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 FIDs.

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

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

3.2. Impact of Decarbonisation

Decarbonisation efforts are expected to cost a lot and are always deemed more expensive than not decarbonising. The impact of decarbonisation is also behind the avoidance of an increase in upstream investment. There are global shortages of funding sources to take care of 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 capitals for extended periods. Besides, today's society strongly tends to hamper and oppose investment in fossil fuel development, sometimes including potential legislations 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, though such signs have receded somewhat since dealing with the recent tight gas supply–demand balance has become essential. If natural gas divestment becomes a decisive trend as a top priority is placed on climate action again, Asia's energy transition and energy security will become more costly, and its relative economic power may weaken.

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, some 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 amount of deepsea projects in Africa, and rising issues of regulations and strict policies on development projects. Figure 3-16 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.
  - ➢ Major international companies have joined the projects.
  - ➢ Significant volumes are expected to be offered on a term basis.

- ✓ 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 sub-sea pipeline between Israel and Turkey.

Asia-Pacific

- ✓ Australia
  - ➢ Several LNG-related legislative reforms are being enforced in 2023, potentially increasing burdens on LNG projects.
  - ➢ LNG project promoters have concerns over the actual impacts of reform to be clarified further.

Americas

- ✓ Canada
  - ➢ The government promotes investment towards the electrification of gas fields and LNG facilities and business opportunities for decarbonisation.
  - ➢ LNG Canada is under construction, with the first production expected in 2025.
- ✓ The United States
  - ➢ Freeport LNG is returning to full operation, making the US 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.
- ✓ Mexico
  - ➢ New Fortress Energy intends to start Altamira FLNG in the third quarter of 2023.

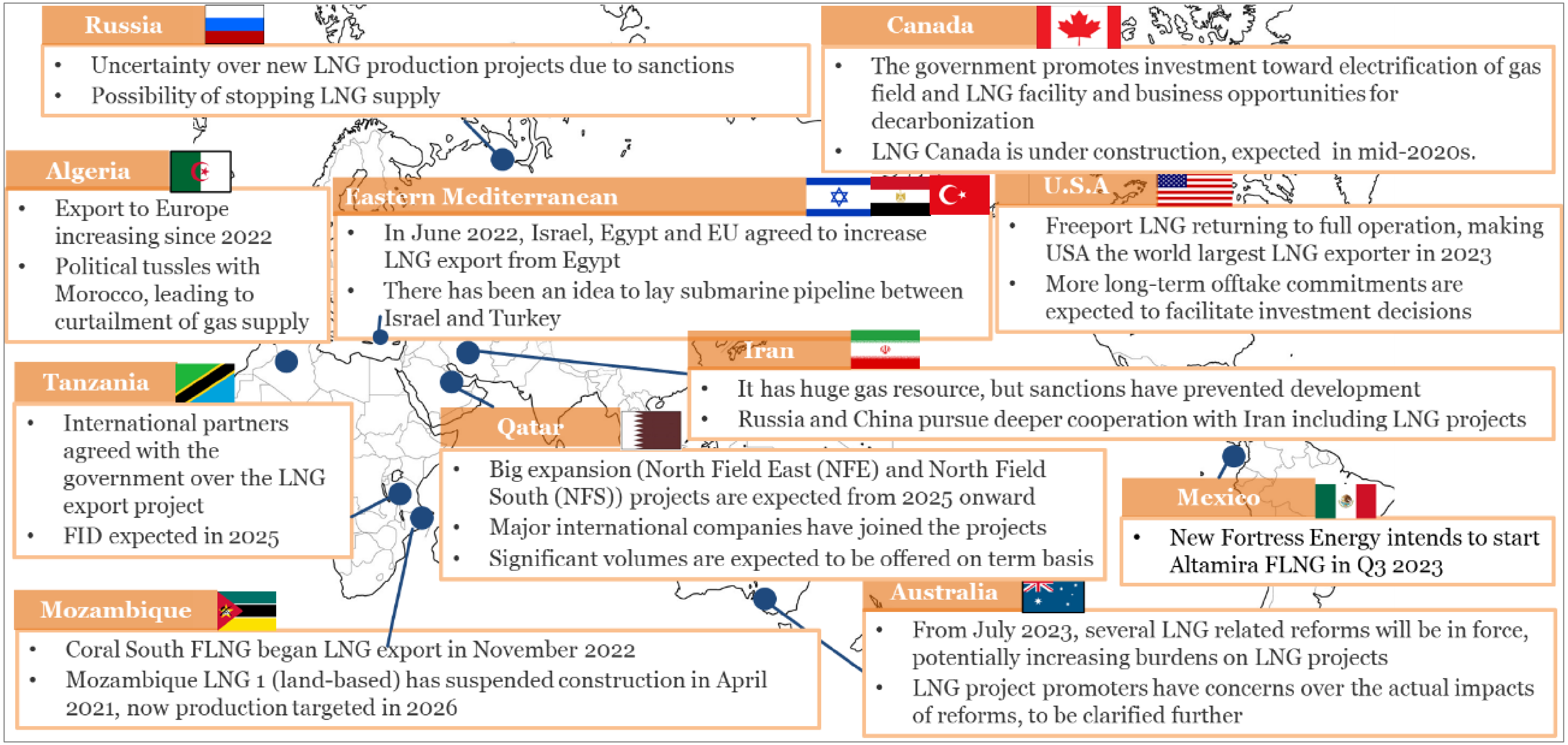
Europe

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

Africa

- ✓ Algeria
  - ➢ Export to Europe increasing since 2022.
  - ➢ Political tussles with Morocco, leading to curtailment of gas supply.
- ✓ Tanzania
  - ➢ International partners agreed with the government over the LNG export project. The FID is expected in 2025.
- ✓ Mozambique
  - ➢ Coral South FLNG began LNG export in November 2022.
  - ➢ Mozambique LNG 1 (land-based) has suspended construction in April 2021, with production targeted in 2026.

Figure 3.16. Examples of Factors to be Considered on the Supply Side



Source: IEEJ Analysis.

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 3.17 is a brief recap of the factors.

Asia-Pacific

- ✓ Australia
  - ➢ Gorgon – temporary shutdown for routine maintenance in December 2021
  - ➢ Prelude – the floating LNG production facility was shut down for an investigation by an 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 is delayed due to COVID-19 by more than a year until 2023
- ✓ Malaysia
  - ➢ MLNG – production at the Bintulu LNG facility has had a shortage of feedstock gas from some gas fields since August 2021. A force majeure of some LNG shipments was notified to LNG buyers in October 2022 due to a failure at one of the pipelines to connect feed gas to the plant, although the negative impact was limited.
- ✓ Peru
  - ➢ Peru LNG – production facility suspended LNG production for 4 months in 2021.
- ✓ Russia
  - ➢ Sakhalin 2 – two trains were shut down for maintenance from July to August 2021. There is uncertainty over its operation after the planned maintenance in July 2023.

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.
- ✓ The US
  - ➢ Calcasieu Pass LNG - failures in power generation and heat recovery steam generator units in March 2023, possibly delaying commercial operations
  - ➢ Freeport LNG – a fire broke out, which halted LNG production. The shutdown led to a cumulative decline in supply of several million tonnes.

Europe

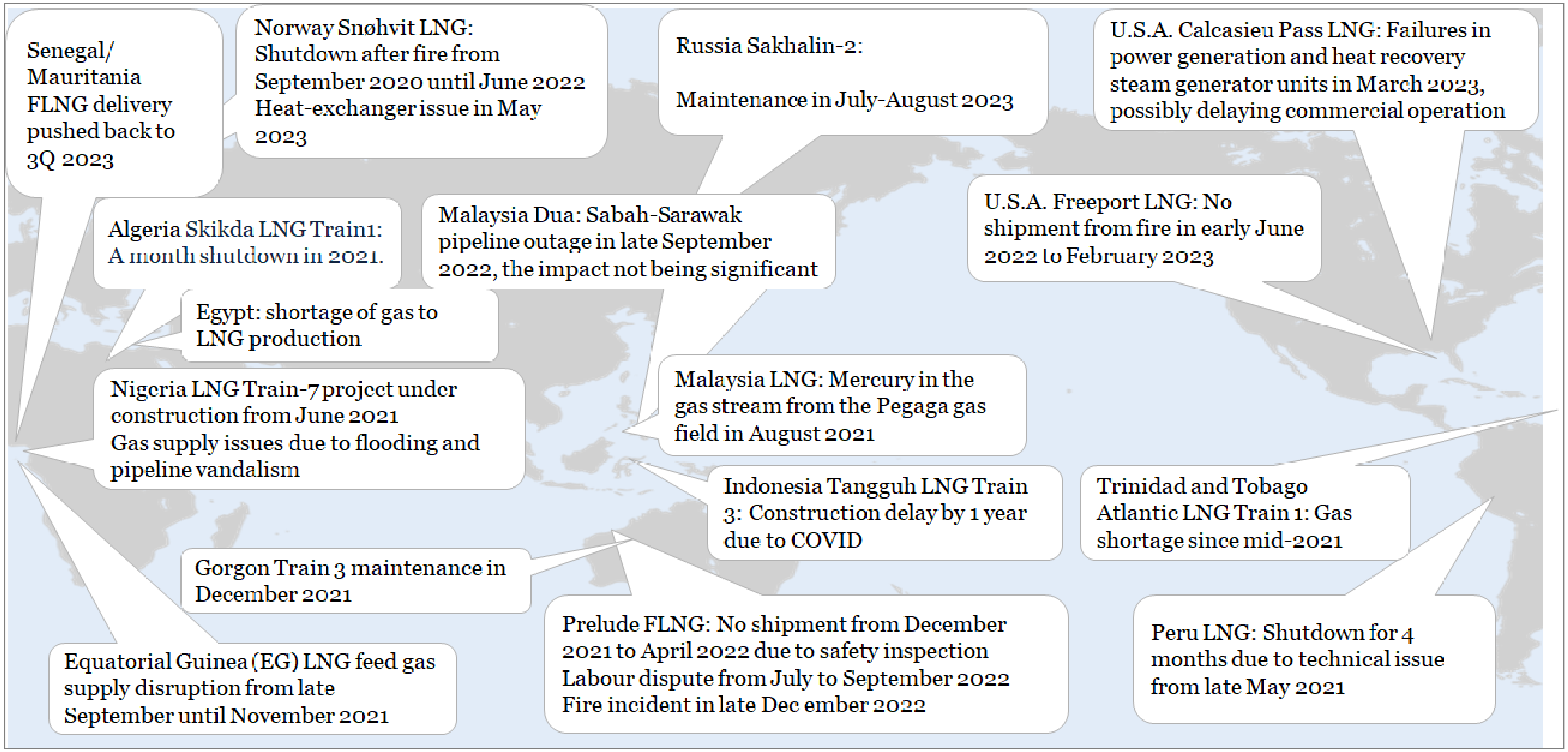
- ✓ Norway
  - ➢ Hammerfest LNG – LNG facility suspended LNG production from September 2020 to June 2022 after a fire.

Africa

- ✓ Algeria
  - ➢ Skikda LNG – temporary shutdown of Train 1 for 1 month in 2021

- ✓ Egypt
  - ➢ LNG production sites - shortage of gas for LNG production
- ✓ Equatorial Guinea
  - ➢ EGLNG – suspended 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 completion of Train 7 delays due to flood and terrorists destroying the pipeline, and the commencement of production is expected around 2025

Figure 3.17. Disruptions of LNG Supply Observed in the Last 3 Years



Source: IEEJ Analysis.

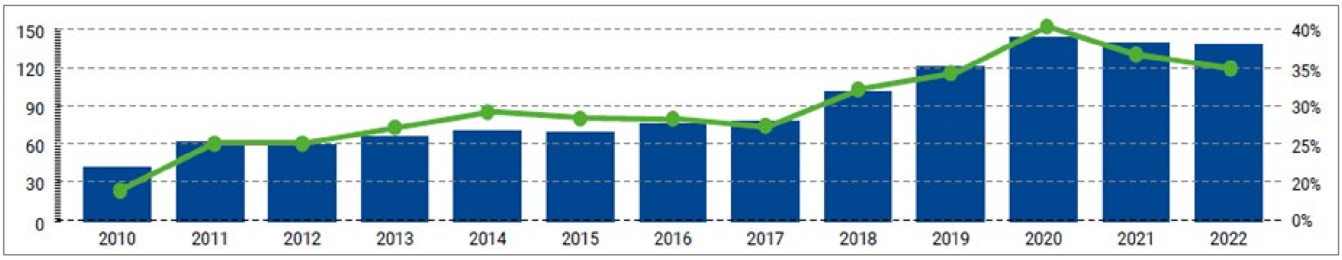
4. Other Factors Causing Price Change

4.1. Increasing Spot Transactions

Due to the political and regulatory demands for decarbonisation and a more effective procurement portfolio, many buyers are unwilling to continue purchasing 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 GIIGNL Annual Report 2023, the world's LNG-consuming markets imported 389.2 Mt in 2022, 134.8 Mt (35%) of which was imported on a spot or short-term basis, and 28% was imported under purely spot transactions (delivered within 3 months after agreements) (Figure 3.18).

Figure 3.18. Share of Spot and Short-term vs Total LNG Trade (Mtpa/%)



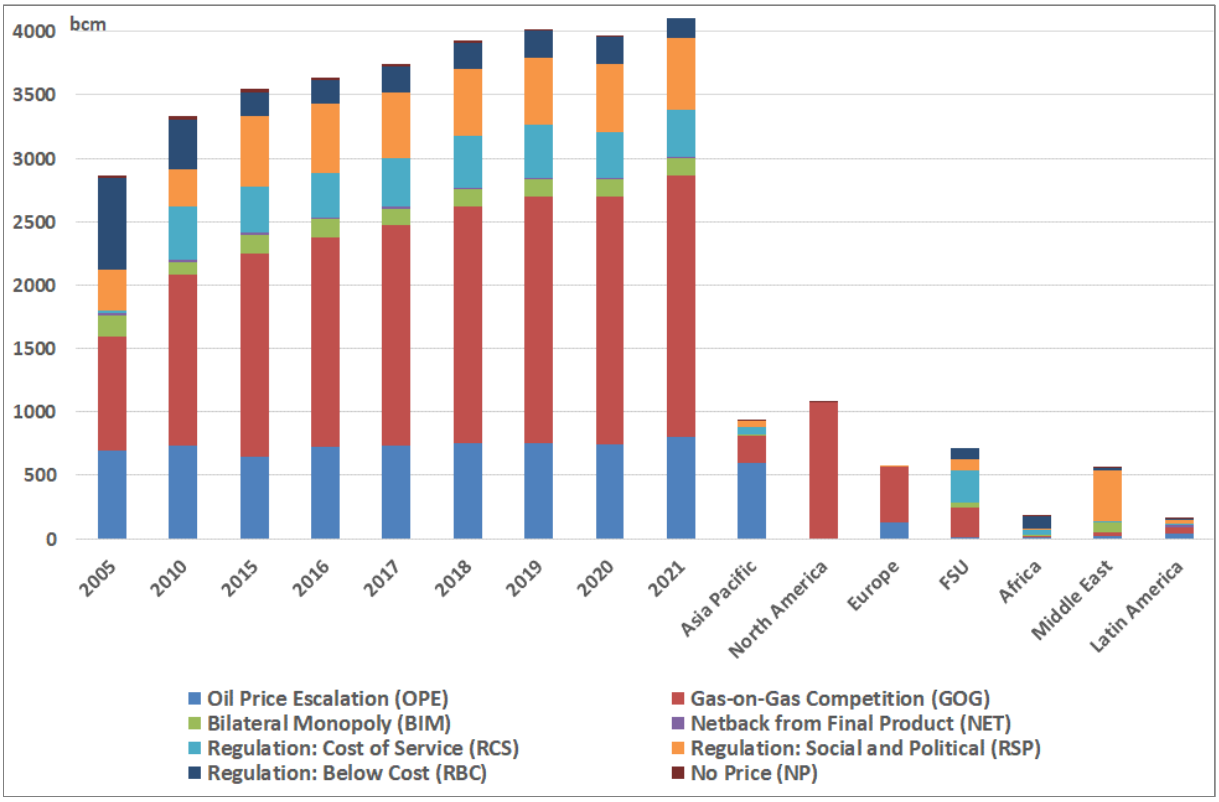
Source: GIIGNL (2023).

4.2. Wholesale and Imported Gas Prices Are Set Differently

Changing pricing arrangements in long-term contracts and increasing 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 out of 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 3.19).

Figure 3.19. Gas Pricing Mechanism



Source: Based on IGU (2022).

4.3. The Remaining Factors to Be Considered

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, 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 LNG projects
- Greater need to enhance measurement, reporting, and verification) in the LNG value chain
- Short-term emission reduction measures (recovery of wasted gas, for example).

Chapter 4
US LNG: Solution to Energy Trilemma

1. Outline and Characteristics of US LNG

The pursuit for carbon neutrality and net-zero emission in ASEAN will rely on transitioning from fossil fuel to cleaner energy. The new source of potential supply from the US is quite 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 US.

The US has become the world's largest producer and exporter of natural gas, and with that role comes great 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 2022, US LNG exports reached approximately 112 Bcm, and will reach 123 Bcm in 2023. By the time all current LNG projects in the US are complete later this decade, US LNG capacity will be roughly 245 BCM/y, a little more than a doubling from current levels. There has been some concern and characterisation of the US government as holding back on authorising exports. But the US administration has authorised exports of approximately 500 BCM/y, four times the current US LNG production and export levels.

Key Characteristics of LNG from the US for Customers

1) Affordable – reasonable price, at least at the FOB point
2) Clean – possibly near-zero carbon LNG
3) Reliable
   – the US shale revolution, a resource to produce for the next 30 years, and tremendous potential
   – produced from thousands of operators driven by market forces, uncontrolled by political forces like a petro dictator who shuts off gas

2. Price of US LNG

Estimated costs and deemed FOB prices of LNG from the US are more reasonable than the recent spot prices and the long-term contracts many Asian countries have made (Figure 1.1).

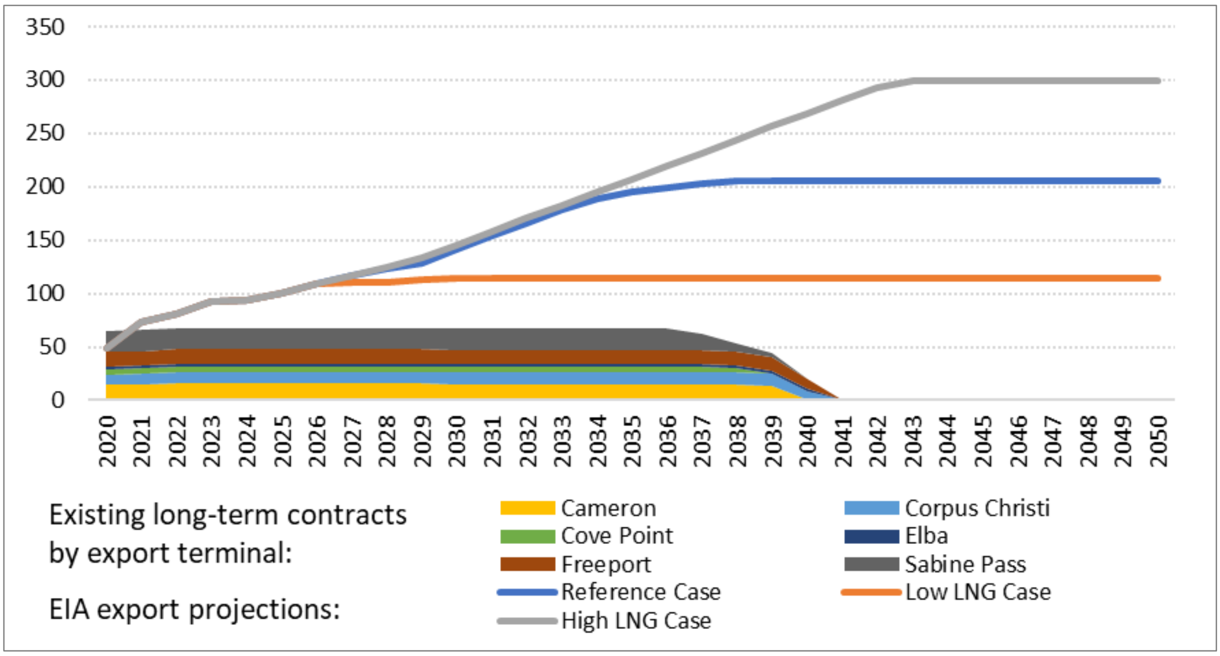
According to one US company executive, 'we can put natural gas on the doorstep of Europe for a cost of $13/MBtu: $4 for production, $2 for transportation through pipelines to the facility, $4 for liquefaction, and $3 for cargoes to destination'.

3. Volume of US LNG

Based on long-term outlooks for US LNG exports, ample LNG trading opportunities will exist between the US and the ASEAN region. The latest Annual Energy Outlook of the US Energy Information Administration (EIA) projects the annual US LNG exports to grow from 81.2 million tonnes per annum

(Mtpa) to somewhere between 114 Mtpa (low case) and 299 Mtpa (high case) by 2050. In the EIA's reference case, US exports will grow to over 200 Mtpa by 2038, more than tripling from today's level (EIA, 2023). Compare this with the modest volume of medium- and long-term contracts US companies have signed. Significant opportunities remain to expand existing US LNG trade relations or sign agreements with new partners, including in the ASEAN region, in the next decade, as contracted LNG volumes from six US export terminals total just 67.7 Mtpa through the mid-2030s (GIIGNL, 2023) (Figure 4.1).

Figure 4.1. Projected LNG Exports Far Outweigh Existing Long-term Contracts (Mtpa)



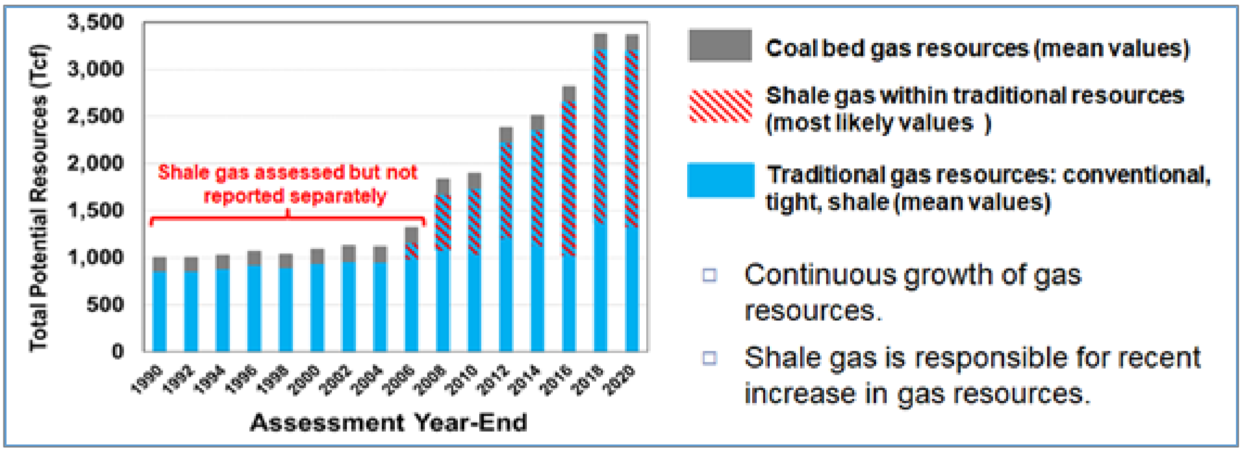
Source: EPRINC analysis from EIA and GIIGNL data.

The US resource base does not limit the capacity to expand natural gas and LNG exports. US future natural gas supplies for worldwide markets rest 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 full documentation that the US resource can produce sustained and sizeable natural gas increases for US and world markets.

The Potential Gas Committee (PGC) at the Colorado School of Mines in Boulder, Colorado, provides highly authoritative and accurate US natural gas resource base assessments. Data through 2020 shows that the US 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 US has an abundance of natural gas. The PGC's year-end 2020 assessment concludes that the US 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.

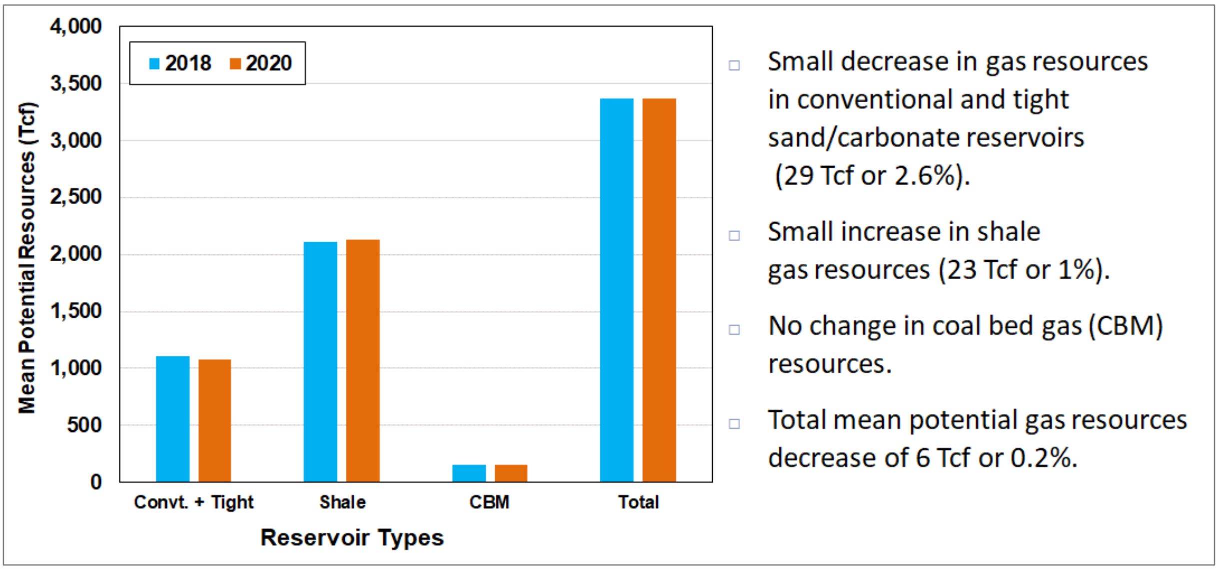
The EIA of the US Department of Energy (DOE) estimates of proved gas reserves confirm PGC estimates and examines resource categories that are additional to the resources assessed by the PGC. When the PGC's assessments of technically recoverable resources are combined with EIA's latest determination of proved reserves in regions not evaluated by the PGC, the US 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 US 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 US Recoverable Natural Gas Resources, 1990–2020



Source: Potential Gas Committee (2020).

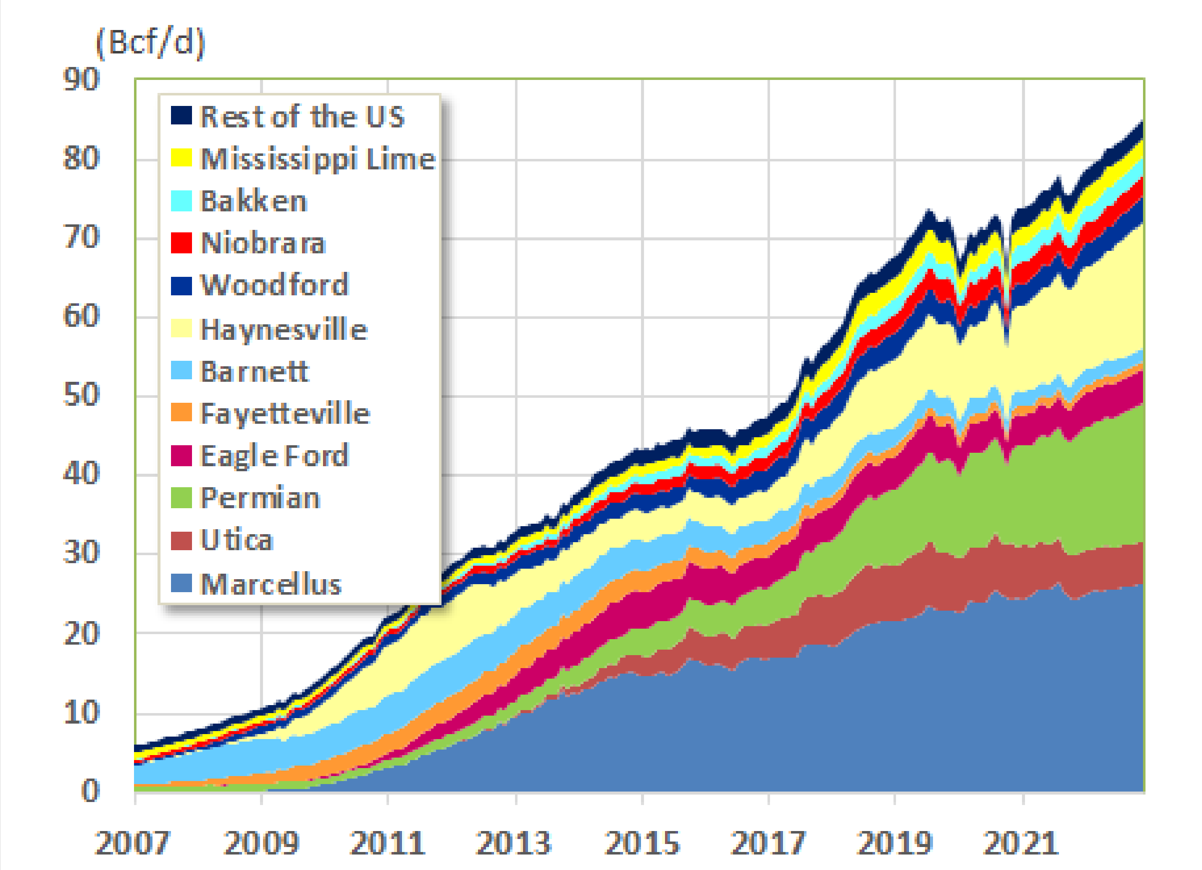
Figure 4.3. Estimates of Recoverable US Natural Gas by Category, 2018–2020



Source: Potential Gas Committee (2020).

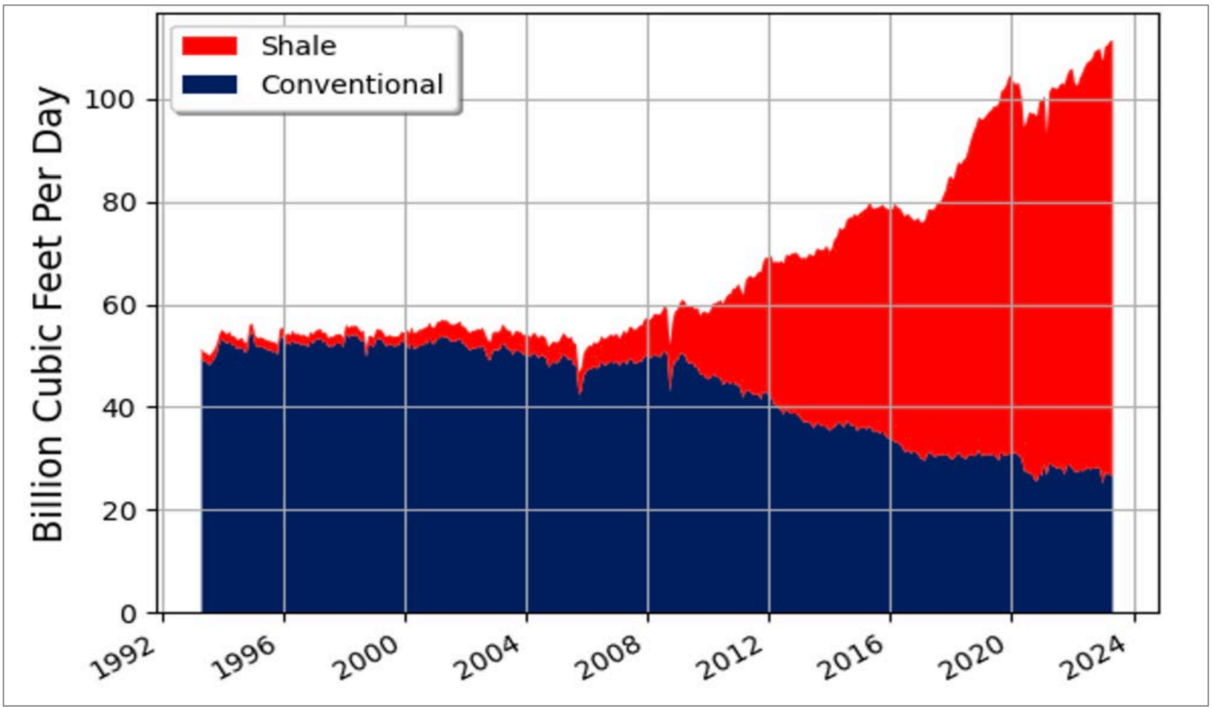
As shown in Figure 4.4, US producers, in response to the massive resource base, have demonstrated the capacity to continue expanding natural gas production, especially from shale dry gas reserves. Figure 4.5 shows that almost all new natural gas production is from shale resources.

Figure 4.4. Monthly US Shale Dry Gas Production, 2007–2023



Source: EPRINC analysis from EIA data.

Figure 4.5. Most Additions to US Supply Were Sourced from Shale Resources



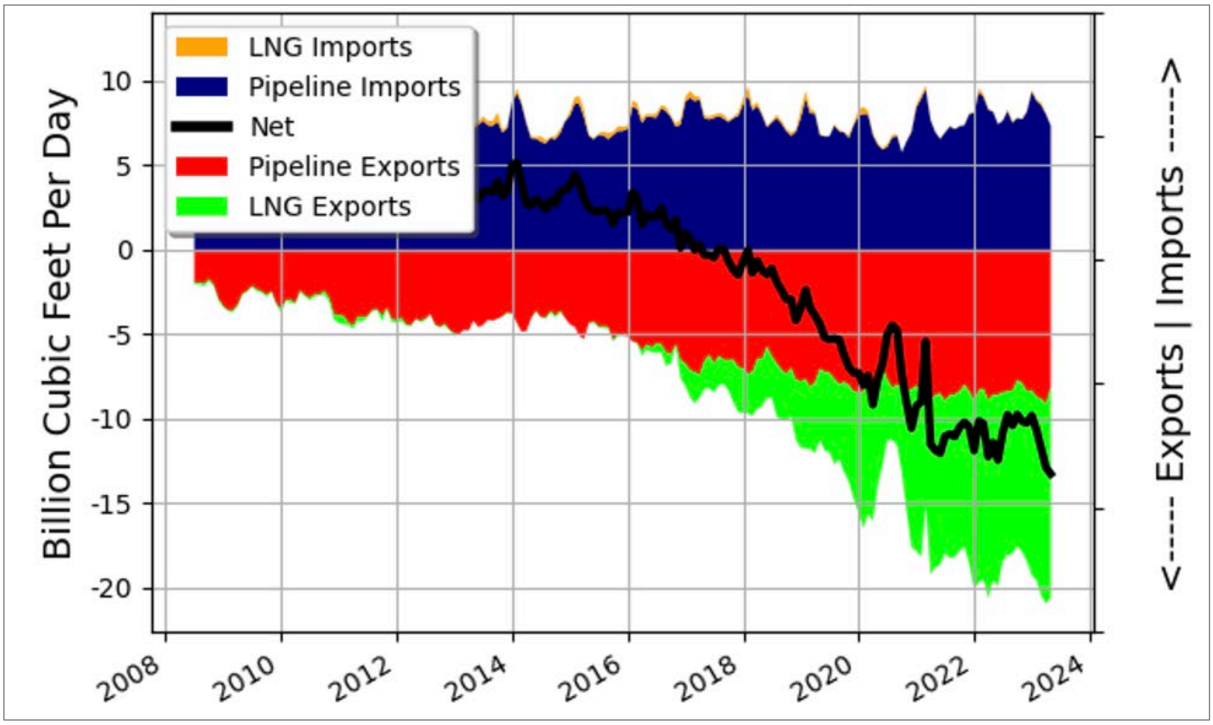
Source: EPRINC analysis from EIA data.

4. Current and Historical LNG Export Trend

4.1. Outline of US LNG Export

The US is fully integrated into the North American natural gas market, where natural gas flows freely across the US–Canadian and US–Mexican border through pipelines. Figure 4.6 shows that the US 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 US is approaching net natural gas exports of 14 billion cubic feet per day (Bcf/d).

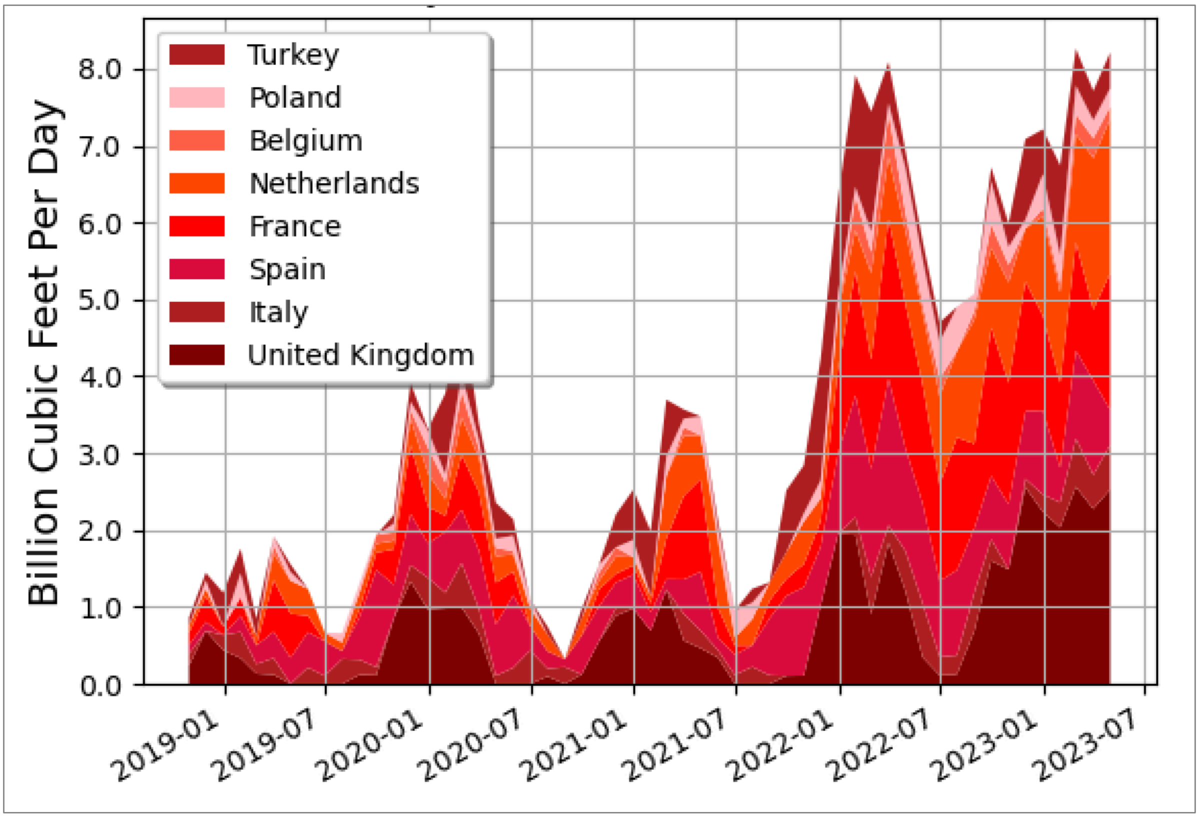
Figure 4.6. US Natural Gas Net Import, Export, and Net Exports, 2009–2023



Source: EPRINC analysis from EIA data.

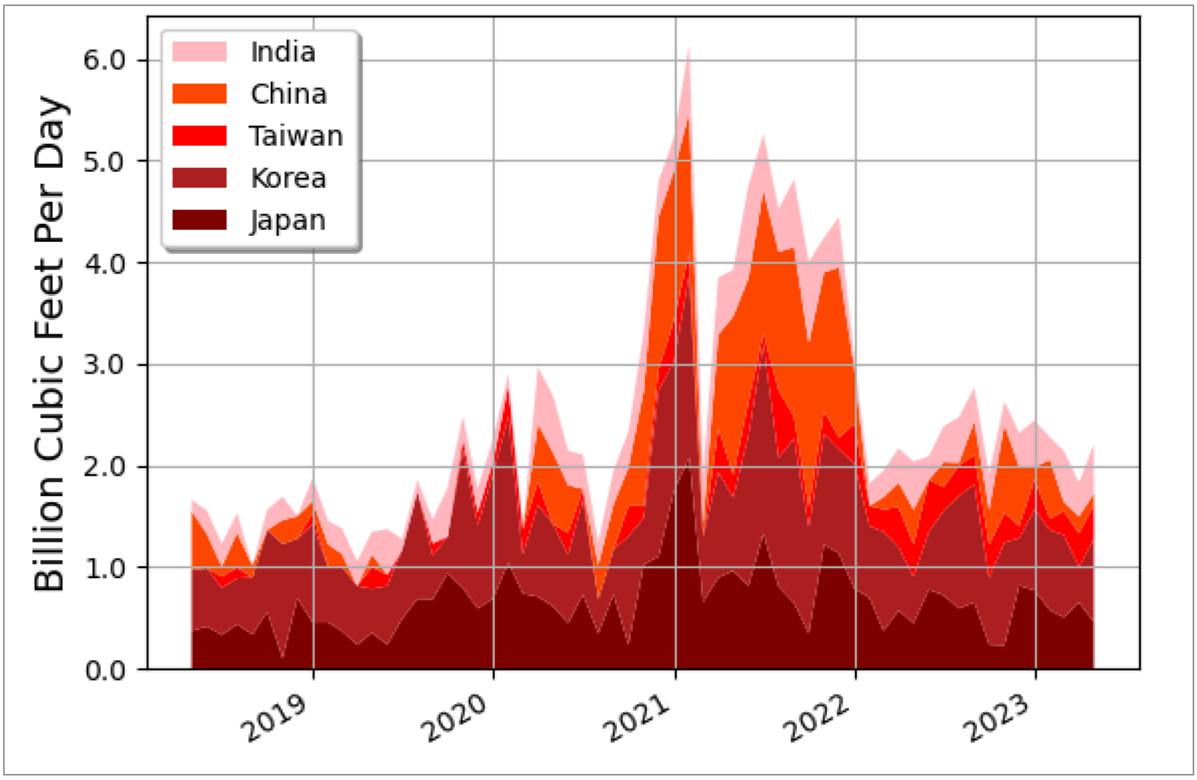
Regarding LNG exports, most US volumes have found markets in Europe, reflecting lower transportation costs and rising values due to the Russian invasion of Ukraine and the loss of Russian supplies to the European continent. Figure 4.7 shows increasing volumes, growing to above 8 Bcf/d into the main distribution hubs in Europe. As shown in Figure 4.8, volumes to Asia fell dramatically, reaching approximately 6 Bcf/d briefly in 2021 but now falling to nearly 2 Bcf/d as the war in Ukraine has continued over the last year.

Figure 4.7. US Worldwide LNG Exports by Destination, 2019–2023



Source: EPRINC analysis from EIA data.

Figure 4.8. US LNG Exports to Major Asian Destinations

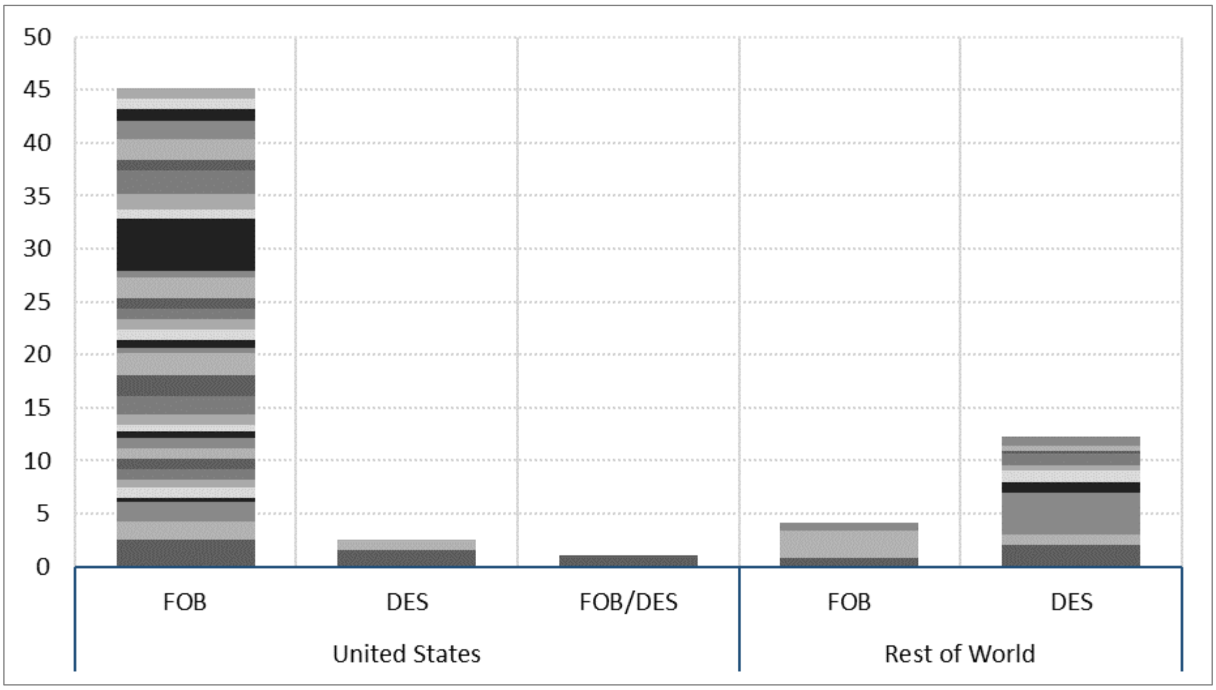


Source: EPRINC analysis from EIA data.

4.2. Destination-Free Clause

Most US LNG contracts offer a destination-free clause (FOB), allowing importers to reroute or resell LNG purchased from the US. This is an improvement over the traditionally more dominant DES clause. With more US companies 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 US exporters in 2022. Of the 39 US contracts, only two have DES clauses. In contrast, only 3 of the remaining 16 contracts by other countries had FOB clauses (Figure 4.9).

Figure 4.9. Medium- and Long-Term LNG Contracts Signed in 2022 by Destination Clause Type (Mtpa)



Source: EPRINC analysis from GIIGNL data.

5. US Projects and Capacity

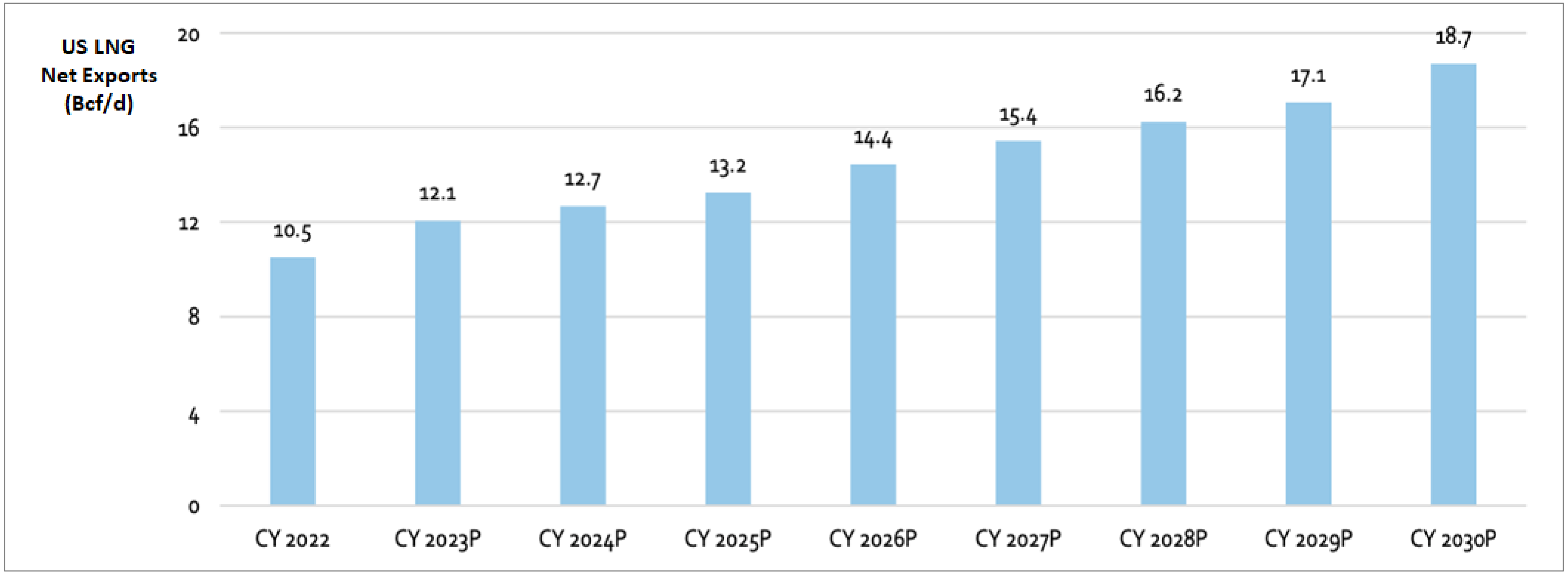
5.1. Outline of US Projects

After reviewing public project information – including permitting; engineering, procurement, and construction (EPC) contracts; sales and purchase agreements (SPAs); financing; and gas and pipeline availability – five additional US liquefaction projects totaling 6.2 Bcf/d of capacity could potentially reach FID in CY 2023. Two US liquefaction projects reached a FID in the early months of calendar year 2022, and an additional 10 projects are approaching a resolution in CY 2023. Nevertheless, there remains some uncertainty that all potential facilities under consideration can find sustained market demand.

5.2. US Liquefaction Project Queue

In its Annual Energy Outlook 2023, the EIA projects US net LNG exports to rise from 10.5 Bcf/d in CY 2022 to 18.7 Bcf/d in CY 2030 (Figure 4.10). There are 27 US liquefaction projects totaling 34.5 Bcf/d of capacity vying to fill this potential gap (Table 4.1).

Figure 4.10. EIA Projects a Steady Rise in US Net Exports over 2022–2030 Interval



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 forecast net LNG imports. In CY 2022, the US imported 0.07 Bcf/d of LNG per EIA STEO data.

Source: Based on data from EIA.

Table 4.1. US Liquefaction Projects Appearing to Approach FID

Project	Owner	Estimated In-Service Date	Capacity (Bcf/d)	FID Date Received	Estimated FID Decision Date
Golden Pass Train 1-2	ExxonMobil / Qatar Petroleum	CY 2024	1.6	Feb-19	
Plaquemines 1	Venture Global	CY 2024	1.8	May-22	
Golden Pass Train 3	ExxonMobil / Qatar Petroleum	CY 2025	0.8	Feb-19	
FLNG	New Fortress Energy	CY 2025	0.4	Jan-21	
CCL Stage 3	Cheniere	CY 2025	1.5	Jun-22	
Plaquemines 2	Venture Global	CY 2026	0.9	Mar-23	
Port Arthur Phase 1 T1	Sempra LNG	CY 2027	0.9	Mar-23	
Delfin FLNG 1	Fairwood Peninsula	CY 2027	0.4	-	CY 2023
CP2 Phase 1	Venture Global	CY 2027	1.3	-	CY 2023
Driftwood Phase 1	Tellurian	CY 2027	1.4	-	CY 2023
Rio Grande T1-3	Next Decade	CY 2027	2.1	-	CY 2023
Texas LNG	Glenfarne	CY 2027	0.5	-	CY 2023
Magnolia	Glenfarne	CY 2027	1.2	-	CY 2023
Commonwealth	Commonwealth	CY 2027	1.1	-	CY 2023
Port Arthur Phase 1 T2	Sempra LNG	CY 2028	0.9	Mar-23	
CP2 Phase 2	Venture Global	CY 2028	1.3	-	CY 2023
CC Midscale T8-9	Cheniere	CY 2028	0.4	-	-
Cameron Phase 2	Sempra LNG	CY 2028	0.9	-	TBD
Freeport Train 4	Freeport LNG	CY 2028	0.7	-	TBD
Lake Charles	Energy Transfer	CY 2028	2.2	-	TBD
Sabine Pass Expansion	Cheniere	CY 2030	2.4	-	TBD
Port Arthur Phase 2	Sempra LNG	TBD	1.8	-	TBD
Delfin FLNG 2-4	Fortress	TBD	1.3	-	TBD
Rio Grande T4-5	Next Decade	TBD	1.4	-	TBD
Driftwood Phase 2	Tellurian	TBD	2.2	-	TBD
Alaska LNG	AGDC	TBD	2.6	-	TBD
Qilak LNG	Qilak LNG	TBD	0.5		TBD
Total	-	-	**34.5**	-	-

Note: Company and media reports. The potential decision date is estimated.
Source: EPRINC Analysis.

5.3. Samples of Projects Nearing FID

Here is a summary of potential issues (if any) to reach FID for each of these 10 projects:

Delfin

- Delfin currently has until June 2024 to commence exports. If the project reaches a FID in mid-2023 and is placed in service within 1 year, it will likely not require an extension.[1] However, if the FID slides into later this year, the project will probably qualify for an extension under the DOE's new policy for granting such extensions. In a March presentation, Delfin stated floating LNG (FLNG) #1 was on track for an FID in 2Q 2023.

CP2

- CP2 is undergoing review for its NGA section 3 certificate at the Federal Energy Regulatory Commission (FERC). The commission scheduled the final environmental impact statement release by 28 July 2023, suggesting that FERC may issue a final order in late 3Q 2023 or 4Q 2023. There does not appear to be a need to expand related gas supply access to accommodate the project. We expect DOE approval of the pending non-free trade agreement (FTA) export licences 60–90 days after a FERC order (late 4Q 2023 or 1Q 2024). On 10 May 2023, engineering company Worley and Venture Global agreed to substantive terms for an EPC contract for CP2 Phase 1, with expectations of commencing construction later in CY 2023.

Driftwood

- Driftwood secured its FERC certificate in January 2019 (including initial pipeline access) and its DOE export licence in May. Neither approval was challenged in court. The commission issued a certificate for additional pipeline access (Driftwood Lines 200 and 300) in April 2023, and re-hearing is pending on the incremental pipeline authorisations. A primary hurdle to achieving FID remains financing. In a May investor presentation, Tellurian stated that it seeks partners to invest 45%–55% of equity ($4.5 million) in Driftwood Phase 1. (The project's total development cost is $14.5 billion per report from Tellurian. DOE data indicate four of five SPAs previously signed with Tellurian were canceled in CY 2022. The remaining agreement with Gunvor, if still intact, is for 0.4 Bcf/d versus Driftwood Phase 1 capacity of 1.4 Bcf/d).

Rio Grande

- On 20 April 2023, FERC reissued Rio Grande LNG's certificate order, which had been remanded (but not vacated) by the US Court of Appeals for the DC Circuit in August 2021 for flaws in GHG and environmental justice analyses. Re-hearing requests from environmental justice advocates are pending. The project received its non-FTA licence in February 2020 (implying a February 2027 deadline to begin exports). In its 11 May 2023 10-Q SEC filing, Next Decade stated that 1.4 Bcf/d of SPAs have been signed versus the capacity of the initial three trains of 2.1 Bcf/d. The company anticipates reaching FID in 2Q 2023.

[1] On 21 April, the US Department of Energy (DOE) established a revised policy for granting export commencement extensions that would provide them only to projects that are already under construction and if the inability to comply with the 7-year deadline is the 'result of extenuating circumstances beyond the control of the licence holder.

Texas LNG

- Also, on 20 April 2023, FERC reissued Texas LNG's certificate order, which had been remanded (but not vacated) by the DC Circuit in the same decision as Rio Grande LNG's case for similar flaws in the GHG and environmental justice analyses. Re-hearing requests from environmental justice advocates are pending. The project received its non-FTA licence in February 2020 (implying a February 2027 deadline to begin exports). The company anticipates reaching FID in CY 2023 and begin operations in CY 2027.

Magnolia

- In CY 2020, FERC granted an extension to begin operations until April 2026. Magnolia's recent request to DOE to extend its non-FTA licence until April 2026 would align first exports with the FERC extension. That said, Magnolia may need to demonstrate to DOE that it had made significant investments in the project to offset the lack of FID. DOE data indicate Magnolia has no current SPAs, and the lack of public information on the project leads us to consider that sponsor Glenfarne may have prioritised Texas LNG over Magnolia.

Commonwealth LNG

- Commonwealth received its FERC certificate in November 2022; re-hearing has been pending. The expected order on re-hearing was struck from the Commission's May agenda and has not yet been issued. We do not expect the DOE Commonwealth's non-FTA export licence until the FERC acts on re-hearing. Once the DOE (presumably) approves the non-FTA export application, the Commonwealth would have 7 years to complete construction and begin exports. We cannot confirm signing an EPC contract for this project, but that may not have been publicly disclosed. (A 5 September 2022 Commonwealth LNG press release details signing two SPAs with Woodside Energy Group Ltd. for up to 0.3 Bcf/d of LNG commencing in mid-2026.) The capacity of the facility is 1.1 Bcf/d.

Cameron Phase 2

- This project holds a FERC certificate and a DOE non-FTA license authorisation (the latter good through 5 May 2026). On its 4 May 2023 conference call for investors, Sempra's management stated that 'Consistent with our disciplined approach to project development, we and the Cameron partners may extend this process beyond the targeted time frame to reduce construction risk, project cost, and optimise the construction schedule through commercial operations date'. Thus, other projects are expected to move ahead of Cameron Phase 2 in Sempra's queue.

Lake Charles

- This project was dealt a major setback when, on 21 April 2023, DOE 'reaffirmed' its policy based on expectations that liquefaction projects should be able to commence exports within 7 years of receiving their export licence approvals in most cases. The DOE denied an application by Lake Charles to extend its commencement date for a second time to December 2028. On 22 May 2023, Lake Charles requested a re-hearing of this decision, contending it had taken the types of actions necessary to illustrate it moved the project forward. Unless the DOE grants rehearing (or the project successfully appeals the DOE's decision in court, Lake Charles faces a 16 December 2025 deadline to begin exports.

Port Arthur Phase 2

- While Port Arthur Phase 1 reached an FID in March 2023, Sempra will likely push for an FID in Phase 2 in 2023. As mentioned above, Cameron Phase 2 appears to have slowed due to cost concerns, which could result in increased investment in Port Arthur. We note that FERC issued a supplemental environmental assessment for Port Arthur 2 in late April after extended inactivity throughout 2022. The commission could issue a certificate for this expansion in late 3Q 2023 or early 4Q 2023. DOE approval of the pending non-FTA export licence will likely be 60–90 days after a FERC order (4Q 2023 or 1Q 2024).

5.4. Conclusions

Some companies may decide to reach an FID before 'all of the boxes are checked'. That said, it is probably appropriate to view receiving permits (Table 4.2), signing EPC contracts (Table 4.3), and signing SPAs (Table 4.4) as key factors in achieving a positive FID. For these factors and our analysis above, the projects most likely to reach an FID in 2023 are Delfin FLNG 1 (0.4 Bcf/d), CP2 Phase 1 (1.3 Bcf/d), Rio Grande Trains 1-3 (2.1 Bcf/d), Texas LNG (0.5 Bcf/d), and Port Arthur Phase 2 (1.8 Bcf/d).

Table 4.2. Permitting Status for the 10 Projects Nearing FID

Project	Owner	Environmental Impact Study Approval Date	FERC/MARAD Approval Date	DOE non-FTA Approval Date
Delfin FLNG	Fairwood Peninsula	11/28/2016	12/21/2016	6/1/2017
CP2	Venture Global	7/28/2023	TBD	TBD
Driftwood Phase 1	Tellurian	1/18/2019	4/18/2019	5/2/2019
Rio Grande	Next Decade	4/25/2019	11/21/2019	2/10/2020
Texas LNG	Gelfarne Group	3/15/2019	11/21/2019	2/10/2020
Magnolia	Gelfarne Group	11/13/2015	4/15/2016	11/30/2016
Commonwealth	Commonwealth	9/9/2022	11/17/2022	TBD
Cameron Phase 2	Sempra LNG	12/16/2016	5/5/2016	7/15/2016
Lake Charles	Energy Transfer	8/14/2015	12/17/2015	7/29/2016
Port Arthur 2	Sempra LNG	4/23/2023	TBD	TBD

Source: Estimates from DOE and FERC data.

Table 4.3. EPC Contract Status for the 10 Projects Nearing FID

Project	Owner	EPC Date Received	EPC Contractor
Delfin FLNG	Fairwood Peninsula	TBD	Samsung / Black & Veatch
CP2	Venture Global	5/10/2023	Worley
Driftwood Phase 1	Tellurian	11/13/2017	Bechtel
Rio Grande	Next Decade	5/28/2019	Bechtel
Texas LNG	Gelfarne Group	5/22/2022	Technip and Samsung
Magnolia	Gelfarne Group	11/15/2015	KBR-SK
Commonwealth	Commonwealth	10/12/2018	TechnipFMC
Cameron Phase 2	Sempra LNG	TBD	-
Lake Charles	Energy Transfer	TBD	-
Port Arthur 2	Sempra LNG	TBD	-

Source: Estimated from company and media reports.

Table 4.4. SPA Signed as a Percentage of Capacity for the 10 Projects Nearing FID

PROJECT	OWNER	CAPACITY (BCF/D)	SPAS SIGNED (BCF/D)	PERCENT OF CAPACITY CONTRACTED
Delfin FLNG	Fairwood Peninsula	0.4	0.1	36%
CP2	Venture Global	1.3	0.9	71%
Driftwood Phase 1	Tellurian	1.4	0.4	29%
Rio Grande	Next Decade	2.3	1.4	62%
Texas LNG	Gelfarne Group	0.5	0.0	0%
Magnolia	Gelfarne Group	1.2	0.0	0%
Commonwealth	Commonwealth	1.1	0.3	30%
Cameron Phase 2	Sempra LNG	0.9	0.0	0%
Lake Charles	Energy Transfer	2.2	1.0	47%
Port Arthur 2	Sempra LNG	1.8	0.0	0%

Source: Company information and media reports.

Chapter 5
Policy Recommendations

This chapter describes possible measures and recommendations to stabilise the LNG market in the 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. Secure Sufficient Long-term Supply Sources

1.1. 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 the LNG supply sustainably. This is because countries could easily switch back to coal as a fuel for power generation if the price of natural gas skyrockets and supply becomes difficult to obtain. As mentioned above, one of the root causes of the high volatility of LNG prices is that the supply volume is relatively rigid with no surplus and is incapable of quickly responding to big and rapid increases in demand. Therefore, it is important to secure a majority of the required volumes of LNG supply in a stable manner.

Although producers worldwide have already made efforts to maximise outputs, it is essential to convince them that consumers in the region certainly require more gas long term. As production has to be connected to the market for the incremental volumes, infrastructure and transportation should be arranged beforehand. In that sense, the industry should take maximum advantage of existing LNG production projects. Existing LNG production infrastructure 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. Gathering previously flared associated gas from nearby oil production sites is an even better option as such an opportunity also reduces GHG emissions.

1.2. 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. North America, Australia, and East Africa may be particularly desirable regarding reserves, distances, and transport costs to the consuming markets in Asia.

Above all, US projects are superior in per-unit costs and FOB prices, volumes, and energy security.

1.3. 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 cargoes 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.

1.4. Consider Options in Russia after Normal Conditions Return

Russia has abundant natural gas resources, and Europe will continue buying Russian LNG in 2023. 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. In the distant future, getting LNG from Russia after the normal conditions return might still be a good option.

1.5. 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. Alliances with Japanese companies could help secure LNG supply.

In addition to its current storage capacity, Japan intends to secure at least one cargo 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 various 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.

2. Enhance Purchasing Power

2.1. 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 Aggregate-EU initiative aggregates demand within the region. It connects many 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 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.

2.2. 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 the latter's 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.

3. Improve Contract Terms and Conditions

3.1. Introduce Measures to Mitigate Fluctuations of Prices while Not Distorting Market Activities

Rather than straightforward limits, certain mitigation measures can be placed on excessive price fluctuations in the trading markets. The EU 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.

3.2. Consider Measures that Enable Larger and Longer Offtake and Delivery Commitments

One idea to avoid price volatility is fixed price contracts, which can insulate consumers from market volatility. Such agreements put guardrails on pricing, offering a collar-type approach insulating sellers from the volatile price links. The fixed price contracts are advantageous and bring the world the ultimate form of energy security.

Long-term LNG contracts are effective in guaranteeing the security of natural gas imports. Procuring LNG at a long-term fixed price frees 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. This is also optimal in terms of energy security. 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.

Procuring a large volume of LNG out of long-term national policy will lead to stable access to LNG, so 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.

3.3. Reduce Destination Restrictions further to Optimise Cargo Movements

Even under long-term fixed 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 cargoes travel much longer distances, the time has come to optimise cargo destinations on a grander scale.

4. Adjust the Limitations and Restrictions in Climate Goals

4.1. 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 always needed to maintain and develop the socio-economic system. Renewable energies are insufficient to ensure the right amount of energy when needed because they are usually inefficient in generating power, highly variable in production, and, in many cases, expensive. Unfortunately, there has been a growing argument in Western countries that using fossil fuels is wrong.

However, it is inconvenient that the general public does not know that most methane emissions are from outside the LNG and gas industry. However, the LNG and gas industry now has to prove and let them know that it contributes to solving the methane emission problem rather than a cause of the problem. It is important to show them how gas is produced without causing harm (emissions).

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 CCS and flaring reduction. There is no reason to be accused of this from a decarbonisation viewpoint. For example, several LNG production projects in the US and regions of the world have adopted CCS, from which LNG should be able to be procured with lower GHG intensity.

4.2. Equitably Evaluate Impacts of Coal-to-gas Conversion in the Region

In the context of GHG, especially methane emission 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, the 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.

4.3. Governments to Provide Proper Guidance and Support Measures

A major obstacle to expanding greater use of natural gas and LNG throughout Asia is the continued resistance of some governments in the developed world to an expansive role for natural gas as part of a cooperative and effective programme to accelerate the energy transition by giving natural gas a more significant role. International financial institutions and official export agencies of many G7 members look reluctant to explore government efforts to underwrite long-term use of natural gas as part of any energy transition strategy.

It is tough to try and get all stakeholders in the Western world to agree that gas should be an essential part of the portfolio, leading to allowing gas. The US is pushing very hard to decarbonise its power sector rapidly. In this context, some Asian countries feel a lot of pressure not to use natural gas and to skip over natural gas and go straight to renewables. Plugging the renewables in the electric grid and guaranteeing reliability is often difficult and expensive.

With proper government guidance and support, all the measures and proposals mentioned above will be more effective. For instance, US LNG producers insist that government policies should be pragmatic and need political support to realise the full potential of US LNG.

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 G7 Energy and Climate Ministers' Communiqué in April 2023:

Relevant Items in G7 Energy Ministers' Communiqué

'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.'

References

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

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

EIA (2023), 'Annual Energy Outlook 2023', 23 May, https://www.eia.gov/outlooks/aeo/

GIIGNL (2023), 'GIIGNL Annual Report 2023', https://giignl.org/wp-content/uploads/2023/07/GIIGNL-2023-Annual-Report-July20.pdf

IEEJ (2022), *IEEJ Outlook 2023*, https://eneken.ieej.or.jp/data/10974.pdf

IEEJ (2023), 'Gas Market Outlook for 2023', 16 January, http://eneken.ieej.or.jp/data/10771.pdf

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

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

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

New Fortress Energy (2020), 'New Fortress Energy Signs MOU with Philippine National Oil Company to Advance LNG Infrastructure', 15 October, https://ir.newfortressenergy.com/news-releases/news-release-details/new-fortress-energy-signs-mou-philippine-national-oil-company

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

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

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

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

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

Potential Gas Committee (2020), 'Potential Supply of Natural Gas in the United States, 31 December, https://potentialgas.org/wp-content/uploads/Milkov_PGC_Press_Conference_2021_Final_10-19-2021-1.pdf

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

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

Praiwan, Y. (2021c), 'NEPC Okays LNG Imports', 5 August, https://www.bangkokpost.com/business/2160147/nepc-okays-lng-imports

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

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

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

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

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