ERIA Research Project Report 2018, No.04

LNG Market Development in Asia

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LNG Market Development in Asia

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ERIA Research Project FY2019 No. 04
Published in August 2019

Foreword

While liquefied natural gas (LNG) has numerous advantages and can enhance economic competitiveness, environment, and energy security (3Es) of Asia, there are several issues and challenges to promote LNG in the region. In last year's study conducted by the Economic Research Institute for ASEAN and East Asia ('Comprehensive Analysis to Unlock Potential LNG Demand in EAS Region'), the following policy recommendations were derived and provided at the annual LNG Consumer-Producer Conference held in Tokyo on 18 October 2017:

1. Securing sustainable upstream investments
2. Developing a more transparent and flexible LNG market
3. Providing financial supports
4. Assisting policy and regulatory developments in Asia
5. Sustaining competitive US LNG export platform

Referring to last year's outcome, this study aims to provide more concrete and specific proposals and action plans to accelerate LNG use in Asia.

The authors hope that this study will provide new insights for the LNG market development in the East Asia Summit region.

Yoshikazu Kobayashi
Leader of the Project

Acknowledgement

This study was undertaken based on close discussions with LNG specialists and industry officials in ASEAN, Japan, and the US. The author particularly would like to thank all the participants in the LNG workshop meeting held in Jakarta on 9 July 2018.

The author also thanks all staffs of the Energy Policy Research Foundation, Inc. (EPRINC) and would like to express sincere appreciation especially to Mr. Lucian Puglirearesi, the president of EPRINC, for his kind and generous support for this study, without which this report would not be possible. Needless to say, all errors and mistakes are the author's responsibility

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January 2019

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Contents

List of Figures

List of Tables

List of Abbreviations

Government Ministries, Departments, and Agencies

APC	Panama Canal Authority
BEA	US Bureau of Economic Analysis
CFTC	US Commodity Futures Trading Commission
DOE	US Department of Energy
DOE/FE	US Department of Energy, Office of Fossil Energy
DOT	US Department of Transportation
EIA	US Energy Information Administration
FERC	US Federal Energy Regulatory Commission
METI	Japan Ministry of Trade, Economy, and Industry
PAB	China Petroleum Administrative Boards
PNGRB	India Petroleum & Natural Gas Regulatory Board
SEC	US Securities and Exchange Commission

Development Banks and Related Agencies

ECA	Export Credit Agency
IMO	United Nations International Maritime Organization
JBIC	Japan Bank for International Cooperation
JFTC	Japan Fair Trade Commission
JOGMEC	Japan Oil Gas and Metals National Corporation
NEXI	Nippon Export and Investment Insurance
OPIC	Overseas Private Investment Cooperation
TEN-T	Trans-European Transport Networks
USTDA	US Trade Development Agency

Policy Research Organisations and Related Entities

EPRINC	Energy Policy Research Foundation, Inc.
ERIA	Economic Research Institute for ASEAN and East Asia
IEEJ	Institute of Energy Economics, Japan

Intergovernmental Economic Organisations

ASEAN	Association of Southeast Asian Nations
OECD	Organisation for Economic Co-operation and Development

Regional Designations

EAS	East Asia Summit

Natural Gas-Related Terms

FSRU	Floating, Storage, and Regasification Unit
LNG	Liquefied Natural Gas

Metrics

Bcf	Billion Cubic Feet
Bcf/d	Billion Cubic Feet per Day

Bcm	Billion Cubic Metres
cum	Cubic Metres
MBD	Million Barrels per Day
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units
MMT	Million Metric Tonnes
MTE	Million Metric Tonnes Equivalent
Mtpa	Million Metric Tonnes Per Annum
MW	Megawatt
Tcf	Trillion Cubic Feet

Abbreviations Not Elsewhere Classified

AMA	Japan's Anti-Monopoly Act
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
EmCA	Emission Control Area
FID	Final Investment Decision
FTA	Free Trade Agreement
GHG	Greenhouse Gas Emissions
HSFO	High-Sulfur Fuel Oil
LNG	Liquefied natural gas
LSFO	Low-Sulfur Fuel Oil
MDO	Marine Diesel Oil
MGO	Marine Gas Oil
NOC	National Oil Company
NYMEX	New York Mercantile Exchange
O&G	oil and gas
SER	Schedule for Environmental Review
Sinopec	China Petroleum and Chemical Corporation

Executive Summary and Key Findings

Key Findings

- Transparent and active spot markets are essential for discovering a price that reflects the fundamentals of supply and demand. This discovery can provide the necessary incentives to build out additional natural gas storage capacity and larger volumes of variable liquefied natural gas (LNG) exports. The absolute volume of flexible LNG supply is still limited as current price benchmarks have yet to gain extensive support by market participants.
- China and India have become a source of substantial new LNG demand. Because both are large, even small shifts in demand patterns contribute to uncertainty and volatility in LNG prices. Other emerging Asian buyers of LNG are also adding to uncertainty as demand commitments are tied to short-term and seasonal requirements.
  - In most Asian countries, companies and governments have little direct experience in the operation and construction of LNG re-gasification facilities and connection to electric power plants and distribution networks. Relevant laws and regulations have not been fully developed, leading to delayed decision-making and project implementation.
  - As LNG bunkering advances globally, there is the potential that bunker fuel markets will become fragmented. Where maritime operators had a limited selection of fuel choices but ubiquitous availability, there now is the possibility of the inverse: many different fuel choices with gaps in coverage across the globe. For LNG bunkering to succeed, intergovernmental coordination is necessary.
  - Supply security has taken on new significance in Asian LNG markets as final investment decisions (FIDs) in new liquefaction capacity have been slow, despite the recovery in world crude oil prices and high natural gas demand in emerging markets such as China. This is of special concern for emerging markets in Asia with substantial prospective LNG growth.
  - Traditional patterns of risk allocation in financing new LNG export capacity are not adequate to meet recent market trends. Buyers and sellers may consider taking another type of risk that they have not taken so far to keep expanding liquefaction

capacity as the demand grows. Supportive policies from governments and new risk-sharing strategies are needed to bring more projects to FIDs.

- The Panama Canal Authority (ACP) recognises its critical role as a transit point and a potential bottleneck of the movement of US LNG exports to Asia. The ACP has eliminated unfair practices and physical limitations of their arrangements for LNG cargo passage.

Summary of Policy Recommendations

The joint study of the Institute of Energy Economics, Japan, and the Energy Policy Research Foundation, Inc. of the future of LNG in Asia recommends relevant stakeholders undertake the following initiatives to support a growing market for LNG in Asia.

- *Acceleration of Destination Restriction Removal:*
  Removal of destination restrictions in LNG contracts amongs all market participants to stimulate spot markets and price discovery. Further actions by anti-monopoly authorities to review and follow up competition-limiting behaviours.
- *Development of a Reliable LNG Price Benchmark:*
  An LNG price benchmark is a missing link of beneficial active spot trades and market liquidity and transparency. Removal of destination restrictions and a strong initiative by major players to identify a benchmark are required. Buyers and sellers require full transparency in the fundamentals of supply and demand.
- *Assistance to Private Investment in the LNG Value Chain:*
  Steady efforts to assist private investment in the LNG value chain should be undertaken by revising the conditions for financial assistance provided by export credit agencies (ECAs) in Japan and in the US. Congressional reviews are ongoing to consolidate the US ECAs so they can more effectively assist private investments in new Indo-Pacific energy infrastructure projects.
- *Engagement with Emerging LNG Markets:*
  Deeper engagement with emerging importers will help market participants to have a better understanding of the demand-side behaviours in emerging markets. Platforms

for policy discussions like the LNG Producer-Consumer Conference should be actively utilised to improve market predictability.

- *Development of a Fast-Tracking Tool for Project Development:*
  A model project template that includes project structure, alternative patterns of risk allocation, and templates for contract terms and relevant documents for the project will help to fast-track the execution of LNG re-gasification facilities, especially in countries with no or limited experience with importing LNG.
- *Preparation for the Emergence of LNG Bunkering Demand:*
  Governments can play an important role in the development of regulatory standards and infrastructure to facilitate the use of LNG for powering ocean vessels. An active and international effort is required to formulate and coordinate appropriate regulations for use and handling of LNG as a bunker fuel and to coordinate operations at different refueling centres.
- *Innovative Investment Plans to Ice-Break Stalled Final Investment Decisions:*
  There is a dire need for innovative ideas to break the current final investment decision deadlock. One such idea may be a packaged investment covering wellhead natural gas production, pipeline, and liquefaction plant construction.
- *Collaboration to Avoid Bottlenecks in the Panama Canal*
  Governments from the LNG-importing countries will collaborate to minimise bottleneck risk by active information sharing and policy discussions.

Introduction

After the conclusion of the 6th Annual LNG Producer-Consumer Conference in 2017, the US and Japanese governments extended their joint efforts to lay the groundwork for building out natural gas markets and liquefied natural gas (LNG) infrastructure into the broader Indo-Asian markets. Japanese and US officials announced a confirmation of joint efforts to expand LNG markets, as well as several new initiatives, at a joint meeting at the Embassy of Japan in Washington, DC, on 5 September 2018. These efforts build on Minister Hiroshige Seko's announcement in 2017 to provide export credit assistance and capacity building for power and LNG facilities in Asia. The Trump administration's 'Asia-EDGE' initiative was announced on 30 July 2018 by Secretary of State Mike Pompeo, entailing US$50 million in investment to help Indo-Pacific partners import, store, and supply energy resources in an example of the cooperative programme.

In response to the challenges in building out the Indo-Pacific Asian LNG market, the US Congress is working on legislation, known as the BUILD Act (S.2463, H.R.5015).[1] The bill would create a US International Development Finance Corporation, a successor to the Overseas Private Investment Cooperation (OPIC), with the ability to acquire equity as a minority investor in projects. It would allow OPIC to double the amount it puts out from US$30 billion to US$60 billion and to conduct feasibility studies. Such an organization would provide an effective partner for Japan's Nippon Export and Investment Insurance (NEXI) and Japan Bank for International Cooperation (JBIC), both of which are active in the Indo-Pacific LNG market. The US-Japan cooperative effort covers more than LNG, and includes advanced nuclear and coal technologies, as well as global gas and energy infrastructure, and designates Southeast Asia, South Asia, and sub-Saharan Africa as important regions. As part of that effort, the two countries signed a Memorandum of Understanding (MOU) on developing energy infrastructure in other countries.

At the same meeting, the importance of the cooperative programme was outlined by Shin Hosaka, METI Deputy Commissioner of the Agency for Natural Resources and Energy, who pointed out that energy security in Asia is directly linked to energy security in Japan, the

[1] The BUILD Act has passed the House of Representatives and, if passed by the US Senate, will come into law at the end of 2018. The US Department of Energy (DOE) has also committed to deepening its work with METI and to promote US LNG exports and greater LNG use in Southeast Asia and South Asia.

largest importer of LNG to date. Mr. Hosaka went on to state that development of an LNG market in Asia will mean more supply available to Japan in times of emergency and more reasonable prices due to competition. He also stressed the importance of US and Japanese cooperation because of the potential to supply stable, flexible energy to Asia. The remarks were reinforced by Frank Fannon, Assistant Secretary of the Bureau of Energy Resources, Department of State, who emphasized that the Indo-Pacific region will be a key source of global energy demand growth to 2040.

Expansion of the US natural gas resource base offers considerable potential to further develop both LNG and pipeline exports, and contributes to higher economic growth. Providing a long-term and cost-effective value chain is an ongoing challenge. Nevertheless, new markets are emerging. Traditional Asian LNG-consuming countries such as Republic of Korea (henceforth, Korea) and Taiwan, and countries in Southeast Asia (Indonesia, Malaysia, Singapore, Philippines, amongst others) and South Asia (India, Bangladesh, Pakistan), as well as China, offer new markets or expansions to existing markets for natural gas.

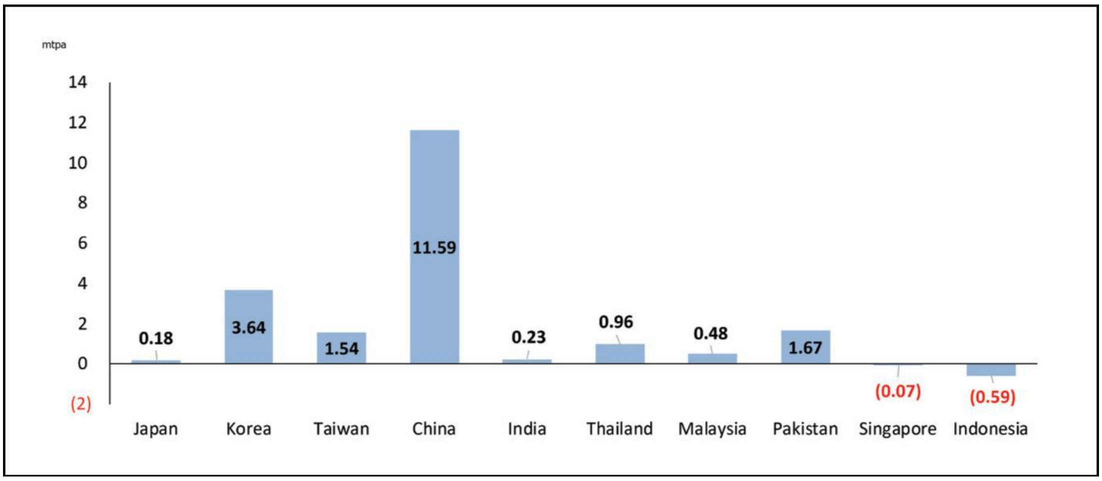
Natural gas is a fuel that can improve air quality, and reduce emissions of carbon dioxide and long-term climate risks. China, which has been a modest importer of LNG, has begun to accelerate its purchases. Yet investment in new LNG export facilities stalled from 2015 to 2016. The slow pace of FID for new projects reflects growing uncertainty over long-term demand and inadequate infrastructure in importing countries. The LNG market still lacks adequate transparency in price discovery, and while improvements are underway, the market has not yet fully adapted to delivering supplies in response to short-term shifts in demand. Financing constraints remain, so projects on their way to FID, both on the supply and demand side, face inadequate infrastructure and ongoing political risks.

Governmental policies will play a critical role in the development of Asian LNG markets by reducing investment risks in new LNG infrastructure in many emerging Asian countries. Financial support and export assistance measures will also play an important role in Asia, particularly for countries that present high credit risks. Technical support would also help Asian countries that have little experience in the LNG business as they embark on LNG imports. This joint research effort recognises that world LNG markets are heading toward more liquidity and transparency, but they have yet to mimic, and may never fully replicate, the open and extensive trading patterns prevalent in the global oil market.

Asian natural gas markets are undergoing an important transition, much of which is supported by prospects of growing LNG exports from the US. For the Asian LNG market to flourish, new supplies and demand centres need to grow and the full range of market participants from sellers and traders to final users such as power utilities need to have confidence that price discovery reflects fundamentals of supply and demand. In this regard, the Institute of Energy Economics, Japan (IEEJ), and the Energy Policy Research Foundation, Inc. (EPRINC) have continued their assessment of the role of destination restrictions as an impediment to arbitrage in the Asian LNG market, one of several market conditions that inhibit sustainable LNG demand in Asia. The US petroleum renaissance has been driven by technological advances that provide access to previously unrecoverable resources. These gas resources will be essential to meet long-term and rising world LNG demand, which, for the Asia-Pacific region alone, is expected to grow rapidly through 2040. This joint IEEJ–EPRINC paper presents our latest assessment of trends in the broader Asia-Pacific market, with a series of recommendations to meet the inevitable rise in LNG demand and accompanying uncertainties faced by both sellers and buyers.

Chapter 1
LNG Markets in Asia

Figure 1-1. 2017 LNG Demand Growth by Country in Asia
(Mtpa – million tonnes per annum)



LNG = Liquefied natural gas.
Source: International Group of Liquefied Natural Gas Importers, The LNG Industry 2018 edition.

1-1. China

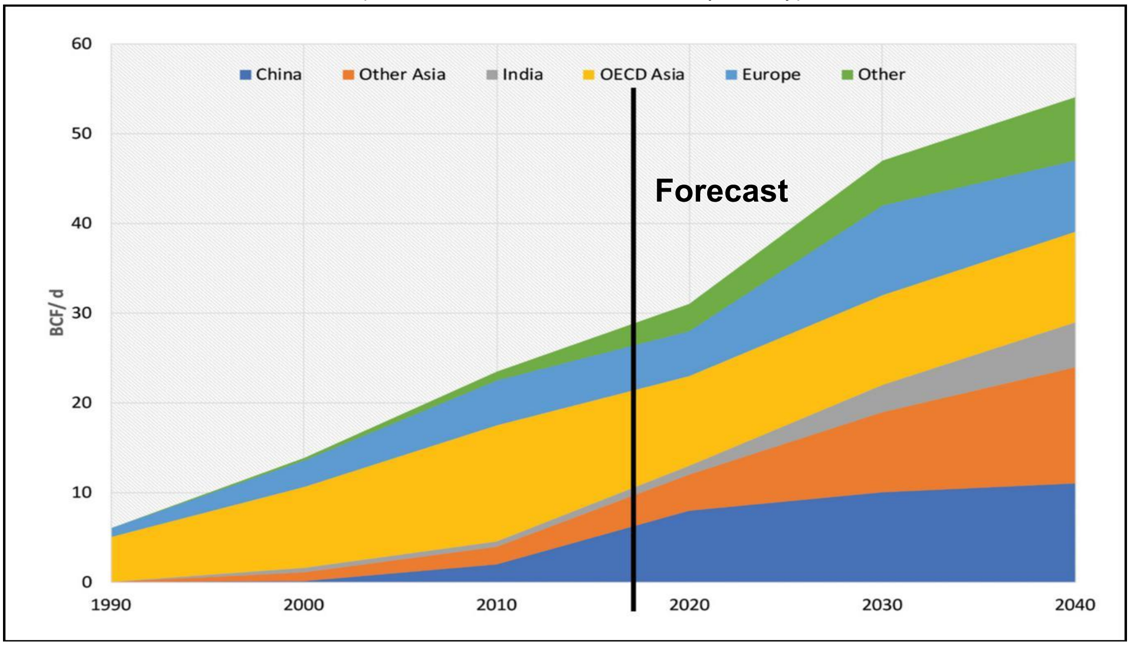
1-1-1. Overview

China's LNG imports have surged 42%, from 27.4 Mtpa in 2016 to 39.0 Mtpa in 2017 by 11.6 Mtpa, making it the fastest-growing LNG market in Asia (Figure 1-1). Natural gas consumption grew by 15%, more than twice the rate of economic growth. China has become the second-largest LNG importing nation, surpassing Korea. The emergence of China as a major LNG market came after years of gas market liberalisation reform and a government-led coal-to-gas switch in power generation.

Official Chinese government policies will drive rapidly rising natural gas demand growth for at least the next decade, although important uncertainties and risks remain. Given the scale of natural gas consumption across the Chinese electric power and urban centres, even small changes in their energy mix will have oversised and long-lasting effects on global LNG markets. Figure 1-2 below illustrates the growing market share of China's LNG imports, along with a forecast through 2040.

Figure 1-2. LNG Imports (1990–2040) by Region

(BCF/d - billions of cubic feet per day)



OECD = Organisation for Economic Co-operation and Development.
Source: BP Energy Outlook 2018

1-1-2. Current Market Environment

China is likely to become as large (or even larger) of a demand centre for natural gas than the European Union (EU) by 2040, presenting a wide range of opportunities and challenges. In addition to the gas demand drivers of greater urbanisation and rising per capita consumption, China also is now actively seeking to replace its older coal-fired electricity generation with gas-fired Combined Cycle Gas Turbine technology, a standard now prevalent in gas-fired electric power production worldwide. Given rising public concern that the country must improve air quality, China's 13th Five-Year Plan (2016–2020) set ambitious goals for increasing the use of natural gas, including almost doubling its share in China's primary energy mix in 5 years. The 13th Five-Year Plan calls for natural gas to provide up to 10% of China's primary energy by 2020 and 15% by 2030. Table 1-1 below lays out the recent Five-Year Plans and their goals.

Table 1-1. Chinese Natural Gas Production Plans and Achievements

(Bcm – billion cubic meters)

Plan	Beginning Level (year)	Planned Achievements	Planned Annual Growth	Actual Achievement	Actual Annual Growth	Fulfillment
10th (2001–2005)	27.2 bcm (2000)	50 bcm (2005)	13.2%	49.3 bcm (2005)	12.63%	Almost
11th (2006–2010)	49.3 bcm (2005)	92 bcm (2010)	13.3%	95.2 bcm (2010)	14%	Yes
12th (2011–2015)	95.2 bcm (2010)	156.5 bcm (2015)	10.5%	135 bcm (2015)	7.20%	No
13th (2016–2020)	135 bcm (2015)	207 bcm (2020)	8.9%	N/A	N/A	N/A

Note: 207 bcm/y is equivalent to approximately 20 bcf/d

Source: Author, based on the publicly available information.

Although the Chinese government is central to the likely energy mix within its economy, it has undertaken a process of gradual price liberalisation for natural gas. Gas prices for nonresidential customers were liberalised starting in 2015. In 2017, the government announced that third parties could negotiate prices and gain access to pipelines and LNG import terminals. These reforms have already produced impressive results. In the last 18 to 24 months, just four non-government players in China now make up almost 10% of the current contracted deliveries to the Chinese gas market (with first deliveries in 2018), which is expected to cumulatively amount to 480 MMT by 2040.

1-1-3. Development Path of Chinese Oil and Gas Industry and Emerging Actors

China has followed a central planning model to develop the oil and gas (O&G) industry with a strong and longstanding military connection. In the 1950s, the 5th Division of the 19th People's Liberation Army was transformed into an 'Oil Corps' to provide the organisation, planning, and engineering to develop the domestic O&G industry. However, oil enterprises' ownership rights were separated from the state in the 1980s with the establishment of the national oil companies (NOCs). The three major NOCs, known as the 'Big Three', are the China National Petroleum Corporation (CNPC), China Petroleum and Chemical Corporation (Sinopec), and China National Offshore Oil Corporation (CNOOC).

Initially, they were separated by specialisation in onshore upstream production, refining, and offshore oil and gas exploration. Nevertheless, after the industrial reform initiated by then premier Zhu Rongji to create a more competitive O&G industry in 1998, CNPC and Sinopec were reorganised as two vertically integrated companies, and the NOCs have each expanded to involve themselves in all areas of the O&G industry, with the distinction between them having disappeared over the years. The NOCs enjoy a certain degree of freedom in their operations to be competitive in domestic and international markets. However, the state owns the NOCs and there is state and party influence within the NOCs. Like other state-owned enterprises, all three NOCs are under the State-Owned Assets Supervision and Administration Commission, a powerful agency directly under the State Council.

Due to the government's efforts to liberalise gas markets, other actors are emerging in the LNG sector in China. Public utilities (Beijing Gas and China Gas) and private companies (ENN, Jovo, Sinochem, etc.) are taking advantage of the third-party access to infrastructure and expanding their reach in China's LNG market. For instance, Beijing Gas plans to import its LNG supply directly through its own anticipated receiving terminal with an annual capacity of 18.25 bcm (12.25 MMt) near Tianjin.

While China developed the Ministry of Petroleum Industry in 1955, there has never been an independent national industry regulator. CNPC spawned Sinopec, CNOOC, and PetroChina, which is in the Ministry of Petroleum Industry. The government's desire to be in direct control of the industry is very evident, and strategic energy security remains high on the list of priorities for the administration.

Technical cooperation with Russia has been critical in Chinese development of its O&G industry since the mid-1950s. When a temporary surplus in oil production emerged in the mid-to-late 1960s, the nation did not hesitate to export it to Japan as a retaliatory measure when relations with Russia had soured in the late 1950s. This oil, sold at a discount, undermined Russian energy export earnings. This is an important historical precedent for US gas exporters to consider. China will adopt a similar strategy for LNG cargo reloads and re-exports within the region and undermine its supplier strategies.

China has toyed with the idea of creating regional, vertically integrated O&G players when it created Petroleum Administrative Boards (PABs), but historically has been unsuccessful in driving operational performance efficiencies, as shown in Tabl-2. In the electricity sector, regional vertically integrated monopolies have operated successfully in China.

Table 1-2. China's Oil & Gas Industry: History, Trends, and Challenges

1949–1959	1960–1978	1979–1991	1992–1998	1998–2008	Today
5th Division of 19th PLA formed into an 'Oil Corps'	PABs rapidly start to develop oil & gas industry	China launches its economic liberalisation policy (1978)	PABs' decentralisation is recognised as 'manageable disaster' (1995)	Big bang industry reform (1998)	Sinopec Group, CNOOC and CNPC today control 90% of production in China
Ministry of Petroleum Industry formed in 1955	China starts exports of petroleum surplus to Japan at significant discounts to Russian prices –undermines Russian export earnings		First price rationalisation intervention to align with international prices	Petroleum Industry qualifies as National Security	PetroChina resembles any other financially successful NOC
China imports oil products from Russia			Industry losses balloon, productivity Drops, and imports rise	Recentralisation though asset swaps	CNPC - PetroChina duality and sector governance issues are centre stage as China gas imports start to grow
Regional PABs formed				CNPC, Sinopec Group and PetroChina are created (1999)	
Oil & Gas Production picks up, but relationship with Russia starts to strain	Relationship with Russia deteriorates			Growth in international activity. Duopolar CNPC begins to take shape	
Petroleum as a strategic risk	**Opportunistic moves for playing off Russia**	**Reorganisation of domestic industry**	**Course Correction in Restructuring**	**Preparing for Rapid Growth**	

CNOOC = China National Offshore Oil Corporation, CNPC = China National Petroleum Corporation, NOC = national oil company, PAB = Petroleum Administrative Boards, PLA = People's Liberation Army.
Source: EnerStrat Consulting.

1-1-4. Factors of Uncertainty

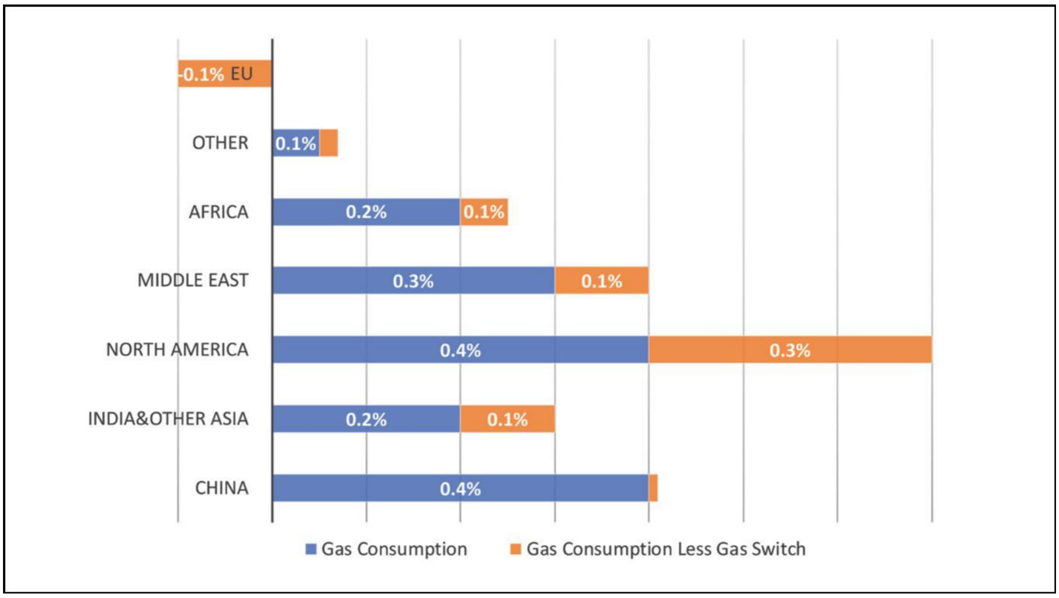
During the winter of 2017–2018, much of northern China experienced significant natural gas shortages. Demand surged, owing to the government's ambitious coal-to-gas switching programmes, and domestic production and pipeline imports could not meet it. Several factors contributed to these severe shortages that will, in turn, shape the demand outlook for Chinese LNG imports.

Ambitious coal-to-gas switching initiative

Coordination amongst many players within China's bureaucratic system has appeared to be inadequate in the massive coal-to-gas switching initiative. This became especially problematic when the coal-to-gas shift in the residential sector in northern China exceeded the planned rate by nearly 25%. In March 2018, a new Ministry of Ecology and Environment was established and given more responsibility than the old Ministry of Environmental Protection, a response to President Xi Jinping's priorities for more attention to environmental issues. This change may help coordinate challenges and attract much-needed public support for the initiative. Figure 1-3 clearly shows that Chinese gas consumption growth would be very adversely affected without government support of a coal-to-gas switch policy in the power sector.

Figure 1-3. Gas Consumption Growth with Regional Contributions, 2016–2040

(% per annum)



EU = European Union.

Note: Gas Consumption Less Gas Switch shows the gas demand growth rate without the government's policy to promote fuel switch from gas.

Source: BP Energy Outlook 2018, Industry Reports, and EnerStrat Consulting.

Inadequate storage capacity

China's natural gas storage capacity is small by international standards, at about 11.7 Bcm, equivalent to just 5% of total consumption. In comparison, the ratio of gas storage capacity to consumption in the US is 17% and Europe is 27%. One constraint on the sustained Chinese LNG demand is the rate at which new underground gas storage is installed, a key feature in meeting seasonal demand.

Overstretched LNG infrastructure

In the winter of 2017, China's 16 LNG receiving terminals became highly overstretched with an average utilisation rate above 105%, and utilisation at some northern terminals exceeding 120%. The pipeline infrastructure to move natural gas from southern terminals to northern demand centres also proved inadequate. To bridge this infrastructure gap, Chinese companies, notably CNOOC and Sinopec, dispatched hundreds of trucks to deliver LNG from receiving terminals in the south to cities in the north at distances of more than 1,000 miles. These truck deliveries reportedly came at a cost of more than US$30 per MMBtu during the winter peak demand, nearly three times the spot LNG price during this period. The efficiency and speed at which the Chinese government could build the missing links between southern LNG terminals and northern demand centres is another uncertainty point which will have a long-term impact on LNG imports.

Pipeline gas shortfalls

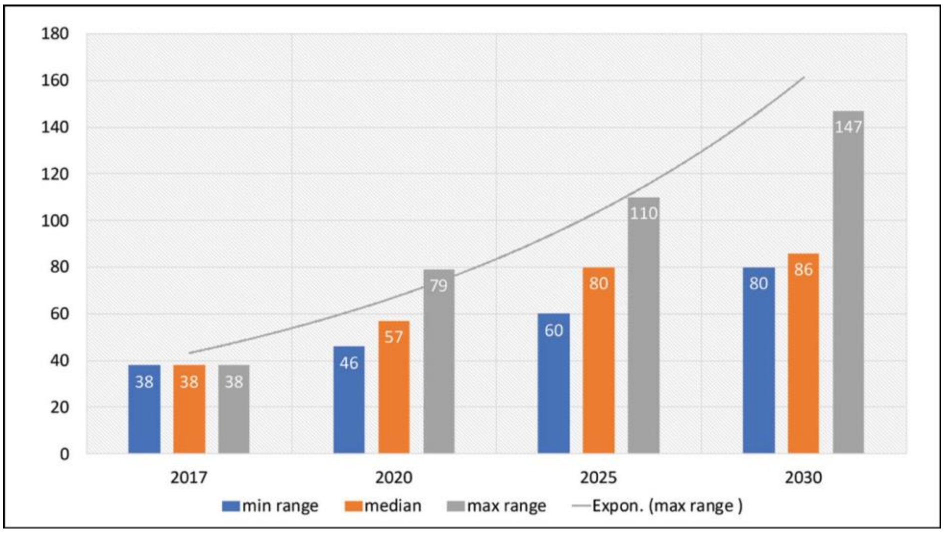
China relies heavily on pipelines from Central Asia for natural gas. In the second half of 2017, pipeline deliveries from Turkmenistan fell substantially. Chinese buyers attempted to offset the reduced volumes with more supply from Kazakhstan and, to a much lesser extent, Uzbekistan. CNPC rushed to bring natural gas wells online ahead of schedule at its Amu Darya project in Turkmenistan. However, pipeline gas imports from Central Asia remained largely flat during the months of peak winter demand. These lower-than-expected volumes put considerable pressure on the natural gas market in northern China and was one of the causes of the LNG imports surge.

Despite several rounds of reform in recent years, China's natural gas prices remain semi-regulated. In the absence of such market mechanisms, it is the regulator's job to keep the system in balance. As China's recent winter gas shortage illustrates, it can be exceedingly challenging to respond quickly to shifts in gas demand.

1-1-5. Demand Outlook

The lack of market-based price signals and the large and influential role of the central government on gas policy adds to uncertainty in any forecast of Chinese LNG demand. The potential range of uncertainty in future demand is shown in Figure 1-4 below.

Figure 1-4. LNG Demand Projections for China (Mtpa)



LNG = liquefied natural gas.
Note: Expon. shows the exponential trend for max range demand growth outlook.
Source: Bloomberg for max range and US Energy Information Association for min range

1-2. India

1-2-1. Overview

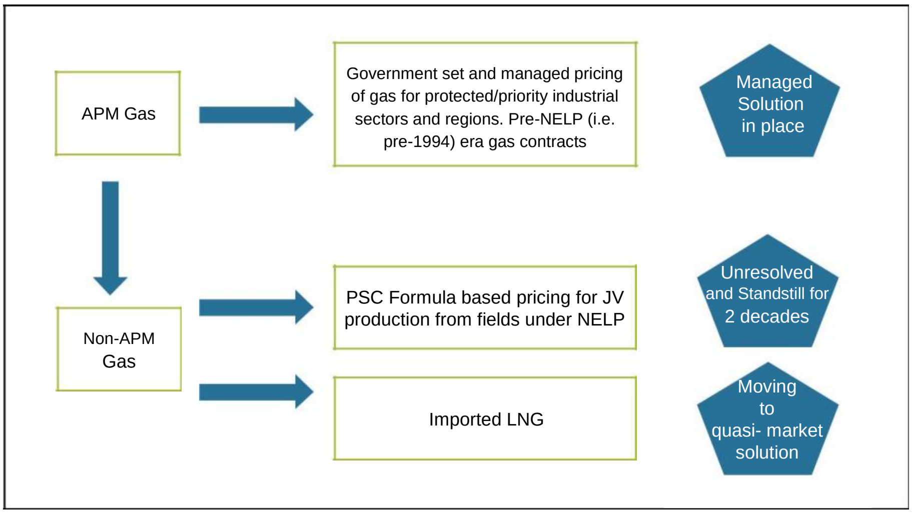
There are many reasons why the term 'wild card' is apt for the Indian gas market. In contrast to most Asian gas markets, power generation is not likely to be a driver of gas growth in India. Other forces, such as rapid urbanisation, industrialisation, and transportation will be the drivers in the short-to-medium term (up to 2025) for natural gas demand growth. Two other features in the Indian gas market are worth noting: (i) gas demand will likely be more price-sensitive than other Asian markets; and (ii) demand growth will be met largely through LNG imports, as there are limited opportunities to develop international pipeline connectivity. The bargaining power of buyers in India is therefore likely to be limited, though recent experience suggests that Indian buyers have managed to secure attractive prices through renegotiations.

1-2-2. Gas Pricing in India

India has historically had an administered pricing mechanism (APM) for gas pricing from domestic gas fields. This was a government-administered price for gas allocated from specific fields to priority sector gas users such as fertilisers, the reasoning behind this being that fertiliser is viewed as critical for food production and hence for food security in India. The price of natural gas before the New Exploration License Policy, the government policy to promote domestic natural gas development that was launched in 1994, was determined under APM.

As gas demand has grown, there has been a concerted initiative in India to develop its own gas fields for production and several policy reforms were introduced, including a production-sharing formula, implemented through a model contract that would provide sufficient incentive for international investors to participate in the Indian exploration and production programme. An Open Acreage Licensing Program is now introduced in India that will allow for a competitive gas price to be offered to the contract counterparts. This pricing mechanism is not under the traditional APM mechanism and a preferable price level can incentivise domestic exploration of natural gas. The programme is not fully implemented due to legal challenges. Figure 1-5 below captures the various pricing methodologies currently being applied in India.

Figure 1-5. Understanding Gas Pricing in India



APM = administered pricing mechanism, JV = Joint Venture, LNG = liquefied natural gas, NELP = New Exploration License Policy, PSC = production sharing contract.
Source: EnerStrat Consulting

1-2-3. The Problems Facing Gas-Fired Power Generation in India

Gas-fired power generation capacity of around 24,000 MW constitutes a mere 7% of the installed power capacity in India; of this capacity, it is estimated that less than 50% is fully operational due to chronic non-availability of gas. Of late, India has experienced a rapid growth in renewable power generation, mainly solar power, which now makes up around 20% of capacity. The effect of growing energy efficiency (many Indian cities are moving towards LED street lighting, as an example), as well as growing renewable generation, has reduced dispatch from gas fired generating plants.

India has also launched (with much fanfare) a policy to install super-critical, boiler-driven High-Efficiency Low-Emission plants, and while quite a few have already been built and are operational, they are running substantial financial losses, as the distribution companies that have signed power purchase agreements are unable to fulfil their payment obligations. About 25 GW of such projects (some operational and some yet to be commissioned) are facing receivership.

Table 1-3 is the breakdown of the current power generation capacity in India. The lenders who are funding new projects are staring at a US$25 billion asset bubble. The situation has highlighted a longstanding concern of fuel suppliers. With regulated fixed tariffs for electricity consumers and fertilisers, the plant owners are asking for long-term fixed-price contracts, and gas suppliers are unable to offer fixed-price gas at levels required to service customers profitably.

Table 1-3. Power Generation Capacity in India

	MW	**% of Total**
Thermal Capacity	222,693	64.76
Coal	196,958	57.27
Gas	**24,897**	**7.24**
Oil	838	0.24
Hydro Capacity	45,403	13.20
Nuclear Capacity	6,780	1.97
Renewable Capacity	69,022	20.07
Total Generation Capacity	**343,898**	

MW = megawatt.
Source: Cunningham, Edward; The State and the Firm: China’s Energy Governance in Context, working paper. https://ash.harvard.edu/files/chinas-energy-working-paper.pdf (accessed 11 June 2019).

Amongst gas-based power plants, 5,000 MW capacity, including GMR Rajamundry, Lanco Kondapalli, Reliance Power Samalkot, RVK Energy, and Panduranga Energy, would land in the National Company Law Tribunal.[2] Of the 24,000 MW of stranded gas power projects, 14,000 MW were allotted gas at subsidised rates by the government and, hence, are receiving part of their tariff from their respective power buyers.

Given declining credit ratings of many power generation utilities, gas suppliers are often unable to identify credible, creditworthy counterparties. The location of these plants is often far from natural gas pipelines. They also face poorly developed regulatory programmes to gain access to gas transportation that has further constrained gas demand growth. Unless access to gas transport systems on a non-discriminatory and transparent pricing basis is available, the power sector demand will remain soft.

There is still a possibility, though remote, that if proposals by the Ministry of Power in India for financial restructuring of the power sector are undertaken, then more opportunities will emerge for gas fuel electric power. However, optimism for gas in India stems not from the power sector, but from growing trends of urbanisation for residential use and for surface transportation.

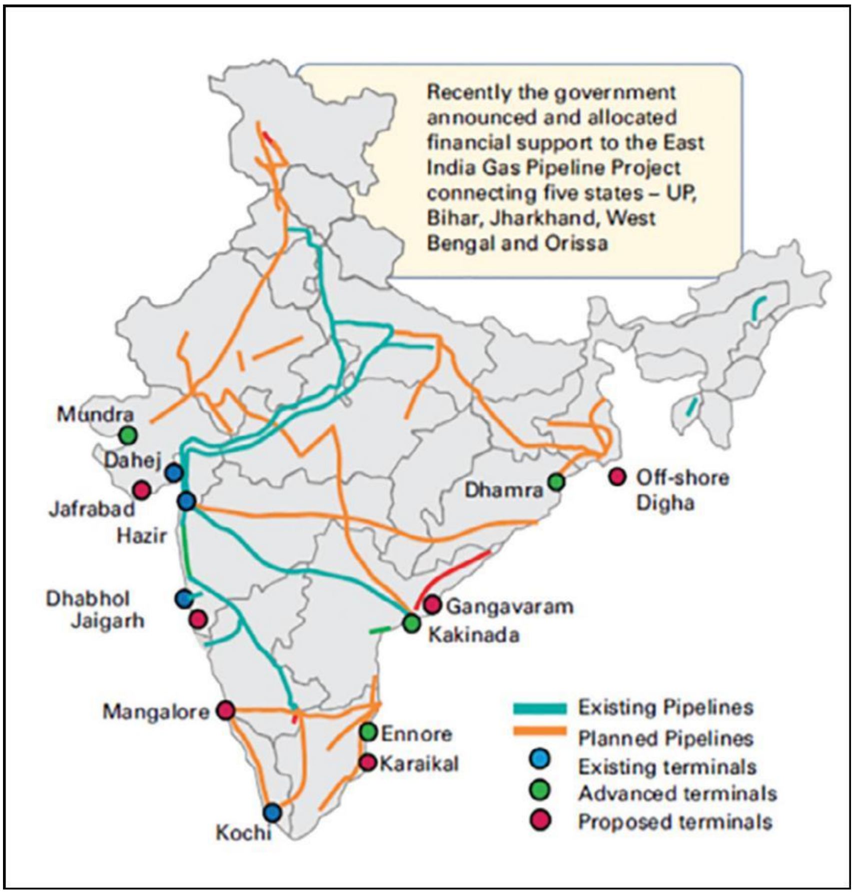
1-2-4. Urbanisation and Transport Driven Gas Growth

Urbanisation is now an irreversible trend across India and a 'gas quadrilateral,' or pipeline network linking major cities across India, is beginning to take shape. A programme driven by the Petroleum & Natural Gas Regulatory Board (PNGRB) is allocating development of City Gas Distribution networks through public-private partnerships in many cities in India.

As Figure 1-6 below shows, large cities across India are already in the process of building their gas distribution networks, whereas another 56 cities are to be allocated until 2021. This will materially change the demand patterns across the country.

[2] National Company Law Tribunal is an Indian government institution that adjudicates corporate issues of Indian companies.

Figure 1-6. Gas Distribution Network in India



UP = Uttar Pradesh.
Source: Enincon Research, PNGRB, PPAC, KPMG

Another aspect of the gas distribution networks is the connectivity to the many special industrial zones in or around these cities. This is expected to bring a new wave of both large and small and medium-sized enterprise industrial consumers. With 43% of the 1.25 billion Indian population living in cities and with more than 53 cities with a population over 1 million, even assuming a low per capita gas consumption, the contribution of this segment to growth of Indian natural gas demand is substantial.

In addition to the urban energy demands, another new set of customer segments is now beginning to develop: urban mass transportation in cities and intercity bus and trucking services experiments are being piloted, including the use of LNG-fueled large trucks. There remain many uncertainties related to the pace of the city gas network development, the ability of the national gas marketing companies to connect customers with speed, and the issue of right of way allocations and land clearance. These are in the process of being resolved.

An important issue relevant to Asian gas and LNG in particular is the pricing formula used in LNG contracts, specifically the role of oil indexation vis-à-vis the gas-on-gas price competition developing at pricing hubs like the Henry Hub in the US, the UK National Balancing Point, or the German NCG (NetConnect Germany). In contrast, India has had a long-running public consultation on its preference for developing a competitive market for gas within the country.

Indian policy makers have been unequivocal in articulating a gas pricing mechanism/methodology that de-couples gas pricing from oil pricing with an objective of securing a lower import price for LNG. This would essentially be a formula with minimal to no oil indexation component.

1-2-5. Indian Gas Demand Projections

Table 1-4 below shows a range of estimates from the International Energy Agency, EIA, BMI Research, McKinsey, and the Government of India's Vision 2030 forecast from an industry study undertaken by PNGRB. PNGRB's forecast is clearly an outlier, and it is worth noting that this forecast assumed no constraints from natural gas prices, infrastructure, or supply availability. EnerStrat consulting undertook an estimate building on regional patterns to provide a separate view of Indian gas demand. Note that with the size of the Indian population, a small shift in demand growth of 1% per annum would move total gas demand in 2040 by well over 100 bcm.

Table 1-4. India Gas Demand Forecast Estimates (bcm)

	2020	2025	2030	CAGR
IEA NPS	64	90	114	6.6%
IEA CPS	67		118	6.5%
EIA REF	70	87	112	5.4%
BMI Research	69	85		
McKinsey	72	92	113	5.1%
GoI Vision 2030	138	179	272	7.8%
EnerStrat Consulting	75	107	137	6.9%

CAGR = compound annual growth rate, EIA = US Energy Information Administration, GoI = Government of India, IEA = International Energy Agency
Source: EnerStat Consulting.

The Gas Vision 2030 demand projections (prepared in 2013) are at odds with other forecasts for Indian gas. Contrary to the PNGRB's expectation that the power sector will emerge as a major gas consumer, the Indian gas market shows no signs of moving toward large-scale use of natural gas as a fuel source. Several features common to all the forecasts are worth noting. Gas demand will grow in India through 2025, but it will be driven by forces outside the power sector. India's demand trends from the Q2 2018 data point to final demand for 2018 at about 66 bcm. It is also likely that by 2025, as more urban centres get connected to Indian gas, that a total volume of 105–110 bcm is possible. As mentioned earlier, almost all this demand will most likely need to be met in the form of LNG due to the lack of international pipelines and domestic production.

1-2-6. Gas Demand Uncertainty in India and China Drive by Different Forces

Both China and India are major growth markets for gas and LNG. Both markets will remain net importers in the near-to-medium term. However, both countries have made substantial commitments to developing other energy sources. China is expected to emerge as the largest nuclear power-generating country and will deploy its own nuclear technology. Both countries have well-developed plans and implementation programmes to deploy clean coal technologies and carbon capture underground storage technologies. In addition, both countries have multiple choices and alternative paths to achieve their stated strategic energy goals. These factors will influence the buy-sell dynamics of the international LNG market.

1-3. Updates in Other Countries

1-3-1. Japan, Korea, Taiwan

Japanese LNG demand in 2017 showed a slight increase to 83.5 Mtpa thanks to colder weather and the industrial sector, although its power sector demand shrank due to the restart of nuclear power plants. While the recovery of oil prices since 2017 may provide some help for demand in the industrial sector, the demand in Japan is set to decline, at least for the short-to-mid term, due to the maturing city gas demand and the successive restart of nuclear power generation.

LNG demand in Korea, once forecasted to gradually decline in the long run, will gain in the coming years thanks to the Moon administration's new energy policy. President Moon announced in June 2017 that Korea would phase out nuclear power plants by limiting the operation of older units. Reflecting Moon's remarks, the Korean government published the 8th Basic Plan for Long-Term Electricity Supply and Demand in December 2017, and it aims to lower the share of nuclear power generation to 23.9% as of 2030 from 30.3% in 2017, while raising the share of renewable and natural gas power generation as of 2030 to 20.0% and 18.8%, respectively. The government also published the 13th Natural Gas Plan in April 2018, which expects that natural gas demand in Korea will grow to 40.5 Mtpa in 2031, reflecting the expected demand growth in the power sector.

Taiwan has a similar energy policy direction as Korea, and will boost LNG demand in the future. Like the Moon administration in Korea, the Tsai administration aims to reduce the dependence on nuclear power by increasing the supply from renewable sources, but within a much shorter time horizon (by 2025). Due to the limited availability of renewable energy and the need for backup power generation capacity in the country, the role of LNG in Taiwan's power mix must grow significantly. One of the potential bottlenecks in such a rapid growth of LNG demand is the country's receiving capacity. Taiwan has two receiving terminals that receive more LNG cargoes than their named capacities, even as of today. Taiwan plans to build the third receiving terminal to accommodate the increasing LNG demand, though any delays in its completion will check its expected demand growth.

The LNG demand of the three countries combined will grow to 133.9 Mtpa in 2030. The demand will show a slight increase overall, as demand growth in Korea and Taiwan will offset the demand decline in Japan.

1-3-2. Southeast Asia

In Southeast Asia, LNG demand growth has stalled. The total demand in the region in 2017 grew only slightly by 0.8 Mtpa to 10.4 Mtpa, and Indonesia even decreased its demand by 0.6 Mtpa. The stagnant demand is largely attributed to price increases. Both Japan LNG Cocktail and spot LNG price regained in 2017 as the crude oil price recovered from 2016 to 2017. Since LNG is mostly used in the power generation sector in the region, it always competes with other energy sources, making price increases deleterious to its relative competitiveness.

Another factor that discourages LNG demand when the price rises is regulation. Many countries in the region have price regulation on energy supplies, particularly electricity. The rise of LNG prices can be diluted to some extent with the prices of other supply sources; however, as the share of LNG to the total natural gas supply grows, its price increase becomes intolerable for local power producers. In Indonesia, in fact, prices of subsidised fuel and electricity have been frozen since March 2018 and they will be so until the end of 2019, when the current administration's term ends (Heany, 2018). This decision worsens the economics of LNG imports and unfavorably affects the country's LNG demand.

Despite the stalled demand growth in 2017, the demand fundamentals in Southeast Asia are strong. Energy demand growth is backed by expanded economic activities, depletion of domestic natural gas production, and increased attentions to air quality and environmental issues, and will surely raise the region's LNG demand in the long run. Natural gas will undoubtedly be a more important energy source and continue to play a larger role in the region's energy mix, and LNG will be the only realistic supply source to the region. LNG demand in the region is expected to grow to 52.7 Mtpa by 2030.

1-3-3. South Asia (Excluding India)

The LNG market in South Asia is rapidly expanding. As of 2018, India, Pakistan, and Bangladesh are importing LNG. Bangladesh has just started to import LNG via a floating storage regasification unit (FSRU) off Matarbari Island. Sri Lanka does not have an LNG receiving facility, but it has several plans to import LNG in the early 2020s (Daily Mirror, 2018). Although in Southeast Asia the higher LNG price discourages imports, demand in South Asia is less sensitive to price levels. This is because oil-fired power generation has a high share of the power mix and LNG can maintain relative competitiveness against imported oil products, even when the price rises as the crude oil price increases. Stagnating domestic production in Pakistan and Bangladesh, existing gas supply infrastructure, and adoption of FSRUs as a quick solution to shortages at LNG terminals will facilitate LNG imports in the region.

Combined demand in Pakistan, Bangladesh, and Sri Lanka will grow at a faster rate than Southeast Asia given their energy demand and supply profile, infrastructure, and capacity to accept international LNG prices. In Pakistan, the gap between natural gas supply and potential demand is still large and the country expects increased LNG will fill in the gap. In Bangladesh, power shortages are also a serious issue and the demand potential for the power sector is significant. The future demand in the three countries will be 17 Mtpa as of 2030.

1-4. Growing Uncertainties in Asian LNG Market

1-4-1. Uncertain Demand Behaviour

As the share of emerging LNG buyers expands, demand in Asia becomes more difficult to foresee. There is no doubt that the demand potential in Asia is large and likely to expand rapidly, though when and where such demand will be realised is highly uncertain. This is because, unlike traditional markets such as Japan, Korea, and Taiwan, these emerging markets have alternative natural gas and energy supply options such as domestic natural gas, pipeline import gas, or other domestic sources such as coal and renewables. Development of receiving, transportation, and utilisation infrastructure has not caught up with growing demand, mainly due to lack of financial resources. Even though such infrastructure is developed, many countries will still have an affordability issue when the international LNG price rises.

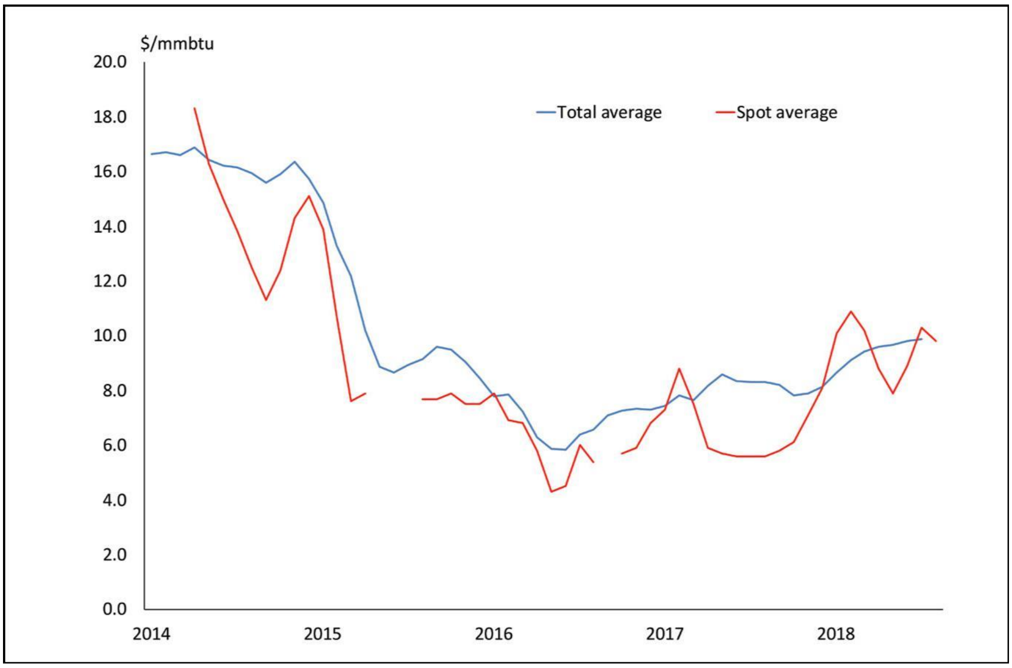
Some emerging Asian countries have already set energy or power generation mix targets, but in many cases, there is insufficient capability or clear government actions to realise the target. Such a lack of policy commitments and administrative capability makes the future energy or power mix more uncertain. In some Asian countries, the government provides their own demand outlook, but this tends to be based on overly optimistic assumptions. Providing a more accurate and realistic demand outlook is very important to efficiently mobilise necessary political, financial, and human resources to develop the infrastructure. Such a demand outlook will be helpful to provide an appropriate signal to international investors who have an interest in investing in natural gas infrastructure in the region.

1-4-2. Larger Seasonal Demand Fluctuation

As LNG demand in Asia grows, the fluctuation of seasonal demand also is magnified, causing large price swings in the spot market, especially in winter. This seasonal demand swing is most notable in the Chinese market, where the LNG import in the peak month was 2.5 times larger than the import in the off-peak month. The development of the spot LNG market in Asia, however, has not caught up with the rapid expansion of the size of the market and is not fully able to accommodate the widened seasonal demand difference. Although most LNG buyers try to moderate their cargo procurements by utilising cargo swaps with other buyers or building up inventory before the peak season, such preparations are not enough to meet the incremental seasonal demand, and many buyers try to procure additional cargoes from the spot market. The size of the international spot LNG market has significantly expanded, but it has not been sufficiently liquid to accommodate recent years' winter demand surge. As Figure 1-7 shows, the spot price tends to be far more volatile compared to the average LNG price, which suggests relative shortage of liquidity in the market. Because the LNG demand in emerging Asian countries is more sensitive to price level, such volatile movement may discourage prospective users of LNG in the future.

Figure 1-7. Average LNG Import Price and Average Spot Price to Japan

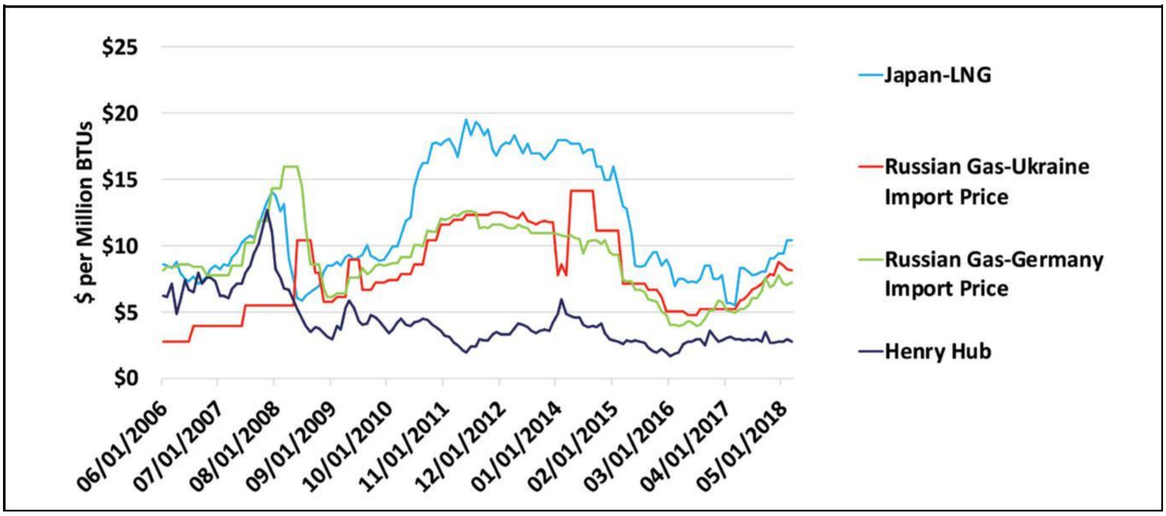
(US dollars per million BTU)



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

Despite volatility in the market, Japan's LNG import price has remained consistently the highest amongst the major importing regions. The average Japanese LNG import price from June 2006 to February 2018 was US$11.6 per MMBtu, while the Russian Gas–Ukrainian import price at the same period was US$7.89 per MMBtu and the average Henry Hub price remained the lowest with the least volatility index at US$4.31. This is shown below in Figure 1-8.

Figure 1-8. Global Natural Gas Prices in Four Regions



LNG = liquefied natural gas.
Source: IMF Data.

1-4-3. Lack of a Clear Legal and Regulatory System

In cultivating natural gas demand, infrastructure development is critical. Because the required investment tends to be very large, risks must be minimised; thus, a clear legal framework must be in place. In an independent gas-fired power producer project, for instance, viability is largely subject to the provisions of the power purchase agreement. The conditions of the price and offtake volume must be strictly kept by local contractual counterparts. Revisions to the initially agreed-upon conditions for domestic political or economic reasons will deteriorate the project economics and harm the interests of the investors. Regulatory uncertainties and unclear arrangements for the foreign entity's investments, foreign currency remittance, customs clearance of equipment, or environment compliance also cause confusion amongst investors, leading to delays. Clear legal and regulatory arrangements with transparent decision-making by host governments will be instrumental for expediting the project development.

1-4-4. Lack of Formal Coordination Platform

In realising a successful infrastructure project, the project must be beneficial to all parties involved; to ensure this, investment risks must be allocated fairly. Close coordination and information exchange are crucially important to obtain mutual understanding and confidence so that the projects can proceed.

In the current project development activities, such coordination is being made amongst investing companies, local counterpart companies, and host governments on an ad-hoc basis, and no formal or regular communication framework or platform is established in most emerging Asian countries. This ad-hoc coordination style usually takes time and delays project development.

A natural gas infrastructure project in Asia tends to adopt an unbundled system where different companies undertake different parts of the value chain. This means that in the project development phase, a variety of companies with different backgrounds and interests must work closely to complete it on schedule. Closer and more intimate communication and coordination amongst relevant parties will be crucial, and the need for such a formal established platform becomes heightened.

Chapter 2
Challenges and Initiatives for LNG Security in Asia

2-1. Why Is Supply Security Relevant in the Current LNG Market Context?

Supply security has been one of the major goals for all energy policy makers, particularly in import-dependent Asian countries; it is never a new nor unfamiliar topic in the region. Yet, under the ongoing LNG market developments, ensuring supply security is gaining more and more significance.

While the LNG market experiences unprecedented market expansion, serious discussions with consumers about supply have been nonexistent. Platforms such as Gastech, the World Gas Conference, and the LNG Producer–Consumer Conference have been used as an opportunity to discuss various issues, including gas supply security, but there is no platform that specifically deals with the issue.

Despite world LNG demand having grown by 1.7 times from 2007 to 2017, and the number of LNG importing countries having more than doubled from 17 to 39 during the same period, there is no official framework where LNG consumers can share the issues and countermeasures about gas supply security like the International Energy Agency in the oil market. The international LNG market is expected to be in a supply surplus condition where liquefaction capacity largely exceeds demand for the time being; any serious supply security issues have not emerged so far, despite rapid market expansion. Yet as the demand from China and other Asian emerging buyers has grown at an unexpected speed, the 'rebalancing' moment of the LNG market from supply surplus to supply shortage may come earlier than widely perceived, that is, in the early 2020s. Supply security risk will be recognised as a more acute issue amongst market players once the market is in a more strained condition. Policy makers in Asia now need to revisit supply security in the LNG market, identify the issues, and consider policy actions.

2-2. Investments in Value Chain

2-2-1. Growing Importance of Upstream and Liquefaction Investments

Supply security in the LNG market will be a function of two elements: value chain investments and market creation. Sufficient supply infrastructure must be in place to ensure security.

Sustained investment to the whole value chain from wellhead production, liquefaction, transportation, and, finally, to re-gasification, must also be secured. In the liquefaction capacity, after the oil price collapse in the summer of 2014, only a handful of projects had reached final investment decision (FID) per year. Since 2017, when crude oil prices began to recover, the conditions for FID have significantly improved because the balance sheet of the O&G industry has improved and the demand growth from emerging countries has become more evident.

Despite this improvement in the investment environment, only two projects (Corpus Christi Project Train 3 and LNG Canada) have achieved FID so far in 2018. While the nature of liquefaction projects requiring huge upfront investment and long-term recovery of investment remains the same, many buyers are willing to commit only to shorter-term purchases and are seeking more volume flexibility as part of longer-term purchase agreements. The divergence of interests between sellers and buyers has widened, which is contributing to the apparent slow pace of new FIDs. Traditional patterns of risk allocation are not adequate to get LNG development commitments from sellers. Buyers and sellers will need new strategies to allocate the long-term development risks to realise liquefaction capacity expansion as demand grows.

Some exporters plan to proceed without long-term purchase commitments. For example, Qatar announced plans to expand its liquefaction from 77 million tonnes per annum to 100 million tonnes per annum by 2024. Mr. Al-Kaabi, CEO of Qatar Petroleum, suggested the country's liquefaction capacity can be raised to 110 million tonnes per annum. These new supplies, if realised, will also help to meet growing LNG demand in Asia. Figure 2-1 shows FID for global LNG projects since 2011.

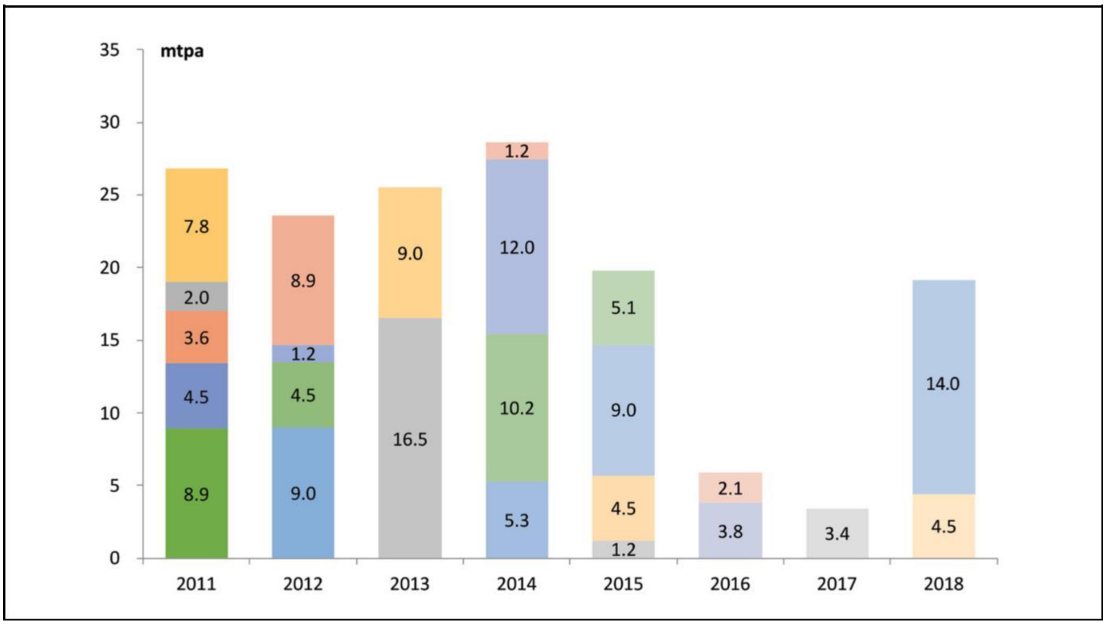
Due to the physical nature of natural gas, supply infrastructure (pipelines) must be built to each individual consumer; thus, the creation of natural gas demand has the same meaning as investment in the downstream sector in an emerging natural gas market. As last year's report shows (ERIA, 2018), US$80 billion downstream investment is required to meet the growing natural gas demand in Asia.[3] Natural gas demand has been growing in Asia, but growth is still checked by the limits of downstream investment so that demand potential is

[3] Countries in this category include members of the Association of Southeast Asian Nations (ASEAN), and India.

not fully realised. Accelerated investment in the downstream sector is equally required to develop the LNG market.

Figure 2-1. Final Investment Decision for Global LNG Projects Since 2011

(capacity in million tonnes per annum: mtpa)



Note: Different color shows different project capacities

Source: IEEJ based on corporate press releases

2-2-2. Ensuring Legitimacy in an Investment Project

Securing a project's legitimacy during its formation and development becomes increasingly important. Understanding the rationale for the project, why a specific developer is chosen from several other companies, and why the location was selected must be determined in a transparent and convincing manner. In Asia, LNG-related projects such as Gas to Power or FSRU installment sometimes have been done on a private and bilateral basis. Such a negotiation style may enable the host government and prospective project developer to have close and intensive discussions and to share more privileged information with each other to fast-track the project. The development process, however, may be perceived as lacking transparency, and thus the project may lack legitimacy in the host country. Perceived lack of legitimacy may cause interruption or even cancellation depending on the political and economic conditions of the host country. Some of the ongoing negotiations of the project development therefore may contain an inherent risk of interruption or cancellation. The project developer is required to ensure the project's legitimacy to manage such risk.

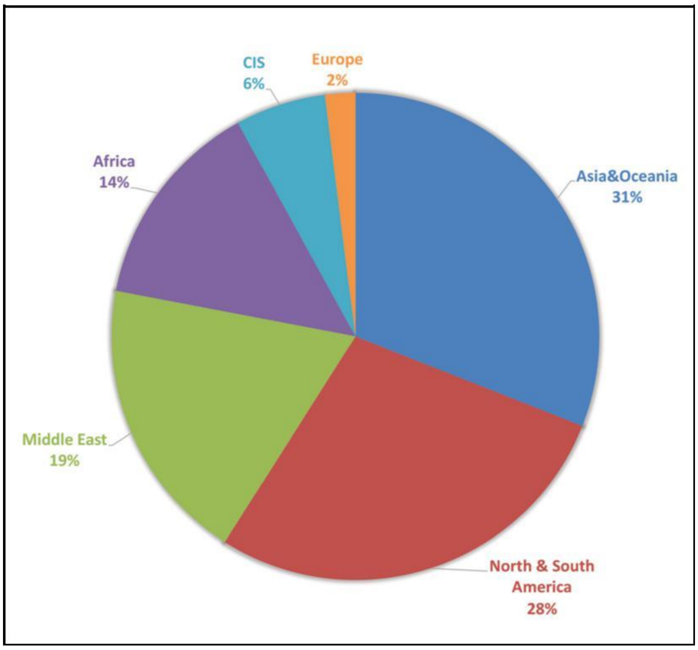
2-2-3. Export Credit Assistance and Other Official Assistance Programmes

The Japan–US Strategic Energy Partnership (JUSSEP) consists of a wide range of joint projects across the energy value chain. Of special importance is the joint effort to expand natural gas electric power generation and re-gasification facilities in Asia and US LNG export facilities, for which export credit or other official assistance programmes are key, as last year's report (ERIA, 2018) pointed out. Official credit and financial assistance for these programmes includes direct involvement of export credit and trade development agencies of both governments. These agencies address political or commercial risks inherent in building out power generation and re-gasification facilities. Government-supported agencies such as the Export-Import Bank of the United States, OPIC, US Trade Development Administration (USTDA), Japan Oil Gas and Metals National Corporation (JOGMEC), JBIC, and NEXI have all been directly involved in LNG projects in the US and throughout Asia.

Several initiatives are worth noting. JOGMEC has provided financial assistance through equity capital and loan guarantees of US$5.8 billion for oil and gas upstream development (including LNG export projects) worldwide. The distribution of equity capital by region is shown in Figure 2-2. JOGMEC's Value Chain Training Program, beginning in 2018, provides capacity building for nine local industry experts and regulatory officials in energy policy, legal structures, facilities development, and transportation solutions for the development of electric power stations, natural gas distribution networks, and LNG re-gasification facilities.

JBIC has been active in supporting LNG projects, and has extended project finance to the Cameron and Freeport LNG projects. For these, JBIC has also extended financing for vessels to bring LNG to Asian markets. These projects have been deemed important for Japan as they contribute to the ability of Japanese utilities to manage LNG price spike risks. Also, as destination restrictions are absent in US projects, they improve the competitive market for LNG in Asia. JBIC played an important role in financing for expansion of the Panama Canal as well, a critical low-cost transport route to Asian markets.

Figure 2-2. JOGMEC-Supported Equity Capital for Upstream Oil and Gas Projects by Region



CIS = Commonwealth of Independent States, JOGMEC = Japan Oil Gas and Metals National Corporation.
Note: The total amount for the equity capital is US$5.3 billion.
Source: JOGMEC.

NEXI has also been active in providing political risk insurance for both Japanese and US businesses that are jointly undertaking LNG projects. Amid international consensus on the benefits of developing LNG markets, NEXI has also shifted its mandate from supporting infrastructure projects only if they supplied LNG to Japan to supporting the projects if they involve Japanese companies (such as Japanese exporters, equity investors, operators, or off-takers). NEXI has provided insurance guarantees for several LNG import projects in the Indo-Pacific region, which have contributed to the regional gas supply security, as well as to US LNG projects. Table 2-1 shows recent projects where NEXI is participating, along with the amount of financial insurance.

Table 2-1. Recent NEXI-Insured Projects

Year	Country	Project	Insurance Amount (US$m)
2016	Indonesia	Tangguh LNG Project Expansion	Non-disclosure
2014	Indonesia	Donggi-Senoro LNG Project	382
2014	US	Freeport LNG Project	1,150
2014	US	Cameron LNG Project	2,000
2012	Australia	Ichthys LNG Project	2,750
2009	Russia	Sakhalin II LNG Project	1,400
2009	Papua New Guinea	PNG LNG Project	950

LNG = liquefied natural gas, NEXI = Nippon Export and Investment Insurance, PNG = Papua New Guinea.
Source: NEXI.

The Japanese government and Japanese companies have a strong interest in developing LNG and power projects in the Indo-Pacific region, since a growing LNG market provides fuel diversity and energy security. The Asian LNG market is on a trajectory to more than double by 2030; this growth will require over US$80 billion in infrastructure investments. In particular, Asia is set to play a larger role in global gas-to-power demand by 2030.

US government agencies, including USTDA and OPIC, have also launched several initiatives aimed at developing gas and LNG markets in the Asia-Pacific region. USTDA announced the US Gas Infrastructure Exports Initiative, which is designed to connect American companies to new export opportunities across the gas value chain in emerging economies. As part of the initiative, the USTDA has identified project sponsors in high-growth emerging markets for gas-related project proposals for US companies.

OPIC, which provides financing through loan guarantees to allow American businesses to take advantage of commercially attractive opportunities in emerging markets, has also launched an initiative to promote LNG markets in the Indo-Pacific region. OPIC expressed its intent to support Virginia-based AES for construction of an LNG receiving terminal and a 2,250-MW, combined-cycle power plant in Viet Nam, which would provide around 5% of the country's power generation capacity and support its continued economic development. This initiative is a step to facilitate critical investment into Viet Nam's energy infrastructure and gas supply chain.

2-3. Market Creation

2-3-2. Making the Market Work

Ensuring the LNG market works is the other critical element of gas supply security. In cases where an unexpected supply disruption happens or an unexpected demand surge occurs, as was observed in Japan after the great earthquake in 2011, marginal supply must be shipped to the highest priority buyers through market mechanisms and price signals. As in the international oil markets, if several spot cargoes are actively traded, and enough liquidity exists in the market, an emergency demand can be absorbed by such market transactions, with limited impacts to the price level.

Under the current LNG trading system, flexible allocation of cargoes is not easy due to the existence of destination restrictions in the traditional long-term contracts. Even if diversion is allowed with the consent of the seller in the contract, cumbersome procedures may have a chilling effect for the buyers to divert the cargo. The LNG market is still too inflexible to allow for optimal allocation of LNG cargoes in an emergency. While the removal of destination restrictions is often cited as essential to realise a more transparent LNG price discovery, as well as to create a more reliable LNG price benchmark, it has another imperative to ensure supply security to LNG importers. Promoting such developments and urging the market player to be more active in spot trading are needed to enhance and strengthen the resilience of the world LNG market.

Increased exports of US LNG, which provides Asian buyers with another supply source besides the Middle East, Oceania, and Russia, is expected to play a major role in enhancing supply security. Although there is relatively low dependence on geopolitically unstable countries for world LNG supply, emergence of new and large-scale supply capacities in the US will bring numerous supply security benefits for Asian importers. Another advantage of the US LNG supply is that it does not have destination restriction, and therefore can forego any process to obtain seller's consent to redirect the cargo destination, thus making it a convenient and effective source.

2-3-3. Updates on Destination Clause Removal

Japan Fair Trade Commission's (JFTC) study on the trading practices of the LNG market in June 2017 reviewed three provisions in the long-term LNG contract, namely, destination restriction, profit sharing, and take-or-pay (JFTC, 2017). The findings are:

- Destination restrictions in the contract are likely to violate Japan's Anti-Monopoly Act (AMA) for Free on Board contracts. As for delivered ex-ship contracts, these types of restrictions are likely to violate the AMA when a seller refuses to consent to diversion, even if a buyer's request is necessary and reasonable.
- Profit share clauses are regarded as unfair trade practice for Free on Board contracts. As for delivered ex-ship contracts, they are likely to violate the AMA when they cause unreasonable profit sharing with a seller, or when they discourage a buyer from reselling because of the seller's request to disclose the deal information.
- On take-or-pay, the study finds that imposing the clause may limit competition when a seller's negotiation position is stronger than that for buyers, as they may unilaterally impose the clause without enough negotiations after the investment is already recovered.

The study urges Japanese buyers not to accept the above clauses in the new and renewed long-term contract, and to review competition-restraining practices for the existing contracts.

The study had a triggering effect on several new developments in the LNG market. Several Japanese buyers succeeded in removing destination restriction clauses from new long-term contracts (JERA, 2017; Tokyo Gas, 2018). As a similar development in other regions, DG Competition announced that it will start reviewing the existing LNG long-term contract by EU member countries with Qatar to check whether it has a clause to limit free movement of natural gas (European Commission, 2018). Similar studies by anti-monopoly authorities of other countries, such as the US Federal Trade Commission or the Korea Fair Trade Commission, if conducted, would deepen the discussion about the appropriateness of destination restrictions in the context of fair market competition.

LNG development is inherently risky for both sellers and buyers because of the large, long-term financial commitments necessary to bring a project to FID. Destination restrictions remove a major risk diversification option for buyers who might be willing to make such a commitment as long as they have an alternative outlet for contracted LNG shipments. A likely outcome of persistent destination restrictions is lower volumes of worldwide LNG exports and a more expensive and smaller market for natural gas power development and re-gasification facilities.

2-3-4. Development of a Reliable LNG Benchmark and Pricing Indices

An established and widely used price benchmark will facilitate active spot trading, which, in turn, will solidify the position of the benchmark. Physical trading activities reinforce the reliability of price benchmarks as observed in the international crude oil market. The LNG market is unique amongst commodities for which a spot benchmark is not referenced in the price formula of the term contract pricing. Creation of a reliable benchmark is an important task for making LNG a more commodified product.

Several benchmarks have been proposed by futures markets, price reporting agencies, and online trading platform companies, but none have been established in the LNG market like the West Texas Intermediate Crude Oil Benchmark Price or Brent benchmarks in the crude oil market. One of the reasons behind the gap in pricing is insufficient spot transactions and stakeholders' reluctance to disclose the price level of their own transactions in a timely manner. Although the spot activities per se have grown significantly in the last decade, they have not reached the level that causes a sustainable influence on the long-term contract prices.

2-3-5. Connection with Atlantic (European) Markets

Interactions with Atlantic natural gas markets will be one of critical features of the future Asian LNG market. The European natural gas market in particular is regarded as a 'balancing place' for the world LNG market, and active cargo transactions will enhance Asian market supply flexibility. This is because the European market has various supply sources, such as domestic gas production and pipeline imports from Russia and North Africa, alongside LNG. Europe also has a large storage capacity at around 5.0 trillion cubic feet (Tcf), as compared to 1.4 Tcf in Asia, and this can absorb seasonal demand fluctuation. This flexible supply generated from the removal of destination restrictions or increased exports from the US liquefaction capacity will enable more intense cargo transactions amongst LNG markets in the world, particularly with European markets. This will improve supply flexibility and secure Asian market supply.

2-4. New Demand Creation: LNG Bunkering

2-4-1. Overview

Bunkering had its origins during the early nineteenth century when the earliest commercial steamships began to be developed. The first fuel for these steam-powered vessels was primarily coal that was stored at ports in large fixed containers known as bunkers. With the expansion and shift in marine fuel types, bunkers and bunkering broadened to reference all aspects of storage, handling, and delivery of fuels used by marine vessels.

From 1907 to 1909, per direction of President Theodore Roosevelt, a portion of the US Navy dubbed 'The Great White Fleet,' sailed the world. Separate from its political goals, it sought to make an operational assessment of the readiness and requirements of its capabilities. Refueling at ports along the way to acquire coal took place every two weeks. Because the coal at these different ports had inconsistent energy content, coupled with a large amount of soot, ash, and other debris, the US decided to shift its fleet from coal to petroleum products that were cleaner-burning and whose energy content was more uniform and predictable.

Similar concurrent determinations were made elsewhere that together augured the global shift from coal to petroleum-derived fuels for marine vessels. Just as steamships were shown to have greater dependability and timeliness than sail, so too did steam-powered ship propulsion systems begin in the 1930s to be displaced by motor ones because of their ability to move larger ships at higher speed. During the mid-1960s, more than half of the world's fleet was motor-driven; by the beginning of the twentieth-first century, this proportion had risen to 98%.

Long-haul commercial global maritime traffic has developed into two general forms:

- liner shipping, the primary one, which operates on fixed schedules and routes with established ports of call; and
- the 'tramp trade,' which has no fixed schedules or list of ports of call.

The largest bunkering hubs by sales volume are Singapore (42.4 million mt), Fujairah (24 million mt), Rotterdam (10.6 million mt), Hong Kong (7.4 million mt), and Antwerp (6.5 million mt). They account for almost 60% of global bunker sales. Coinciding with the development of liner shipping, these bunkering hubs prospered by being both port facilities along major maritime routes, as well being close to major refining centres. Their location has ensured that long-haul liner vessels deviate little, if at all, from their respective voyages, avoiding time and financial costs when bunkering. Refinery proximity means that there is minimal fuel transportation cost and little chance of shortages. Bunkering (refueling) can be done while cargo loading and unloading takes place. Tables 2-2 and 2-3 below offer summary views on bunker markets, vessel numbers and sizes, and fuel requirements.

Table 2-2. Global Shipping Fleet by Category and Tonnage for 2017

Category	Number of Vessels	DWT (million)	% of Total DWT	Average DWT/Vessel
Oil Tankers	10,152	535	28	52,685
Bulk Carriers	10,884	797	43	73,188
General Cargo	19,601	75	4	3,817
Container Ships	5,154	246	13	47,654
Other	47,370	210	12	4,433
Total	93,161	1,862	100	19,985

DWT = dead-weight tonnage.
Source: United Nations Conference on Trade and Development.

Table 2-3. Global Fuel Consumption by Ship Type in 2015

Category	Fuel consumed (mte LNG)	Number of vessels	Average consumption (mte LNG)
Container	52.5	5,009	10,491
Bulk carrier	43.6	10,650	4,097
Oil tanker	31.6	6,395	4,938
Chemical cargo	14.2	4,720	2,999
General cargo	13.2	10,973	1,202
LPG/LNG tanker	12.7	1,687	7,509
Cruise	9.6	477	20,170
Ferry (ro-ro and pax)	10.2	5,288	1,933
Vehicle/co-co	11.4	2,236	5,658
Service	8.8	25,317	397
Refrigerated	3.8	4,876	779
Offshore	3.5	785	4,477
Other + Unclassified	23.0	21,021	1,094
Total	238.1	99,434	2,393

LNG = liquefied natural gas, LPG = liquefied propane gas, ro-ro = roll on/roll off.
Source: DNV & ICCT Data from OIES

2-4-2. Regulatory Shifts

Currently, the array of bunkering fuels is on the cusp of a major shift. While it might not be as disruptive as the transition from sail to steam, it is as significant as the transition from coal to petroleum-derived fuels. The primary driver is the International Maritime Organization's (IMO) decision to drastically curtail sulfur emissions in bunker fuels.

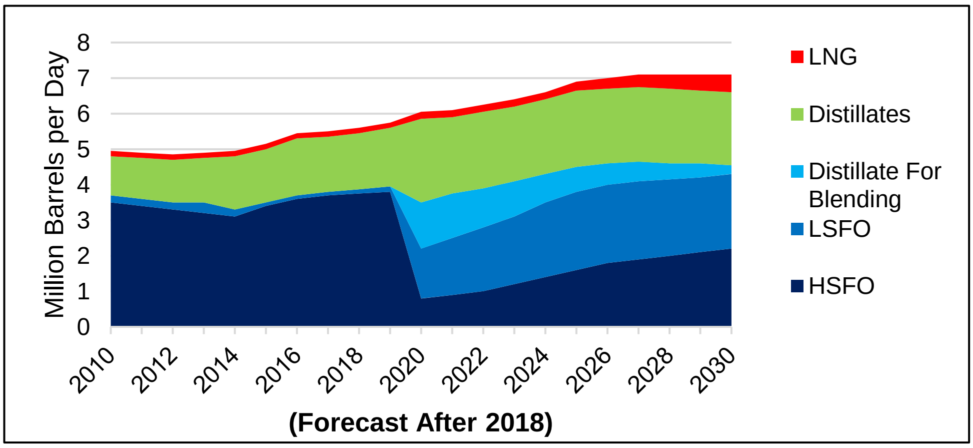
On 27 October 2016, the IMO, an agency of the United Nations, announced that it would require marine fuels' maximum sulfur levels to be reduced to 0.5% from current maximum limits of 3.5%; this rule is set to be binding on 1 January 2020.

There are two reasons for the mandate:

- to protect human health, given that marine vessels are a major source of sulfur pollution in coastal cities (ships contribute about 13% of total sulfur-dioxide emissions; this is more than 2,000 times the level allowed for motor vehicles on US highways); and
- to protect the global environment.

This ruling is the most recent in a series that began with the first IMO rule enacted in 1983. Currently, there are over 90,000 marine vessels; all are subject to the IMO decision. Each of the constituencies that are involved and/or subject to this rule agree that there will be major impacts on all fossil-derived fuels. However, there is no consensus amongst forecasts on the demand size of different marine fuel types after this rule goes into effect.

Figure 2-3. Potential Displacement of HSFO with Other Fuels



HFSO = high-sulfur fuel oil, LNG = liquefied natural gas, LSFO = low-sulfur fuel oil,
Note: Analysis based on various sources.

2-4-3. Overview of Bunker Markets, IMO Compliance, and EmCAs

Currently, marine fuel demand is approximately 6 million barrels per day (MBD). Of this, about 3.3 MBD is high-sulfur heavy fuel oil (HSFO), 2.5 MBD is low-sulfur heavy fuel oil (LSFO) and middle distillates, and 0.2 MBD-equivalent (or 3% of 6 MBD) is LNG. Breaking this down further, about 2 MBD of the 3.3 MBD of HSFO will have to be displaced by other low- or non-sulfur fuels. Currently, there are four foreseeable solutions:

- use LSFO;
- install or purchase vessels with scrubbers, devices that are attached to exhaust systems to remove polluting matter such as sulfur;
- use variants of middle distillates such as marine gas oil (MGO) or marine diesel oil (MDO);
- convert to or purchase LNG-fueled vessels.

Already, high-sulfur marine fuel consumption is restricted in certain continental coastal areas; these are known as Emission Control Areas (EmCAs). Since 1 January 2015, only fuels with a maximum of 0.1% sulfur content are allowed in EmCAs, which include:

- the Baltic Sea EmCA (adopted 1997, enforcement began in 2005);
- the North Sea EmCA (adopted 2005, enforcement began in 2006);
- the North American EmCA, including most of Canada and the US (adopted 2010, enforcement began in 2012); and,
- the US Caribbean EmCA, including the US Virgin Islands and Puerto Rico (adopted 2011; enforcement began in 2014).

China has its own EmCA, where a 0.5% sulfur limit came into effect in 2018.

2-4-4. IMO 2020 Policy Compliance Options

LSFO

LSFO requires no fundamental capital change from a shipping operator’s perspective. However, additional desulfurisation is costly, thereby raising consumers’ overall fuel prices.

Scrubbers

Scrubbers allow shipping operators to continue using HSFO. However, the retrofitting costs average about US$4.5 million per vessel, with the possibility of reaching as high as US$10 million. Operators are then faced with the dilemma of disposing of the sulfur-contaminated residue: release it into the sailing waters or store it onboard for port disposal.

Looking at the business case, scrubber investment becomes compelling if the HSFO-LSFO price differential is wide enough. By example, a typical Aframax vessel consumes almost 100,000 barrels of fuel oil per year. If the differential is such that HSFO costs US$5.5 million less per year than LSFO, then a US$4.5 million scrubber investment is economically prudent.

MGO/MDO

Low-sulfur MGO and MDO offer another alternative to satisfying IMO 2020 compliance. However, like LSFO, these fuels will be costlier because of the need for more desulfurisation, as well as to divert refinery streams from other fuel production and markets, notably the heating oil, diesel, and jet fuel pools. Furthermore, there is concern regarding the availability of low-sulfur MGO and MDO. In anticipation of the IMO ruling, fuel producers have tested several MGO and MDO fuel formulations, but have not announced their respective commitment to which one to use. This elevates the uncertainty of what types of fuels will be available when the IMO ruling comes into effect.

LNG

Of all the available fuels, LNG produces no meaningful sulfur-dioxide pollution. It also contributes significantly to the reduction of particulate and nitrous oxide emissions. While on an energy basis natural gas is considerably less costly than petroleum-derived fuels, LNG's critical drawback is that it has less energy density than fuel oil. Therefore, LNG-fueled vessels require larger onboard tank capacity, and the need for more bunkering facilities along maritime routes because of the necessity to refuel more frequently. In addition, current estimates put the cost of LNG-fueled vessels at US$8 million to US$12 million higher than comparable oil-fueled ones with a longer investment recovery period than scrubbers (up to 3 years).

2-4-5. Possible IMO 2020 Compliance Scenarios

The whole supply chain sees the IMO implementation challenge as perplexing. With fuel representing between 60% to 80% of a shipping operators' costs, the lowest cost alternative is obviously the most appealing. Since three of the compliance alternatives require some sort of capital investment, the challenge then becomes to estimate the direction of fuel prices (as one headline correctly summarises the situation: '[The] Multibillion-Dollar Quandary: Buy Cleaner Fuel or a Fuel Cleaner?'). The most likely compliance path is expected to be greater reliance on low-sulfur fuels, whether they are LSFO, low-sulfur MGO, or MDO. Nevertheless, scrubber and LNG alternatives are expected to be significant.

Currently, the IMO expects there to be 3,600 vessels with scrubbers by 1 January 2020. Most market analysts see this forecast as being aggressive with the general view being closer to between 1,500 and 2,000 vessels. However, once the IMO 2020 sulfur rule compliance modalities become clearer, and fuel price spreads return to stability and clarity after 2020, these same market analysts expect scrubber installations to increase to approximately 8,000 in 2025, and another 50% above the 8,000 units by 2030, or about 15% of marine vessels.

Unequivocally, all forecasts of LNG marine consumption show that demand growth will be spurred the most by the IMO 2020 sulfur rule. However, the range of forecasts varies considerably. Conservative estimates foresee LNG comprising 7% of global bunker demand by 2030; more aggressive ones project 30% in this same interval. Currently, there are about 650 vessels that can use LNG. However, most of these ships (about 525) are involved in the LNG supply chain—tankers, bunker vessels, or floating, production, storage, and offloading vessels) and consume 'boil-off' (LNG which gasifies while vessels are in transit). About 70 LNG-consuming vessels are medium-to-large ships, including tankers, containerships, and bulk carriers. They account for about 1 million LNG tonnes of consumption per year. The balance are smaller intra-regional ships, the bulk of which are car/passenger ferries in the EmCAs, primarily the Baltic and North Sea ones, the areas with the strictest EmCAs.

There are currently approximately 135 LNG-fueled vessels on order for near-term delivery. Of the large, long-haul variety, this includes 33 tankers, 23 cruise ships, and 20 container ships. Altogether, these additional LNG-fueled vessels represent between 1.2 and 3 Mtpa of new LNG demand, as shown in Table 2-4.

Table 2-4. LNG-Fueled Vessels in Use or Under Construction as of May 2018

	In Operation	Under construction	Proportion of total fleet (in %)	Potential LNG consumption ('000 tonnes)
Container	3	21	0.48%	251.8 to 609.3
Oil + Chemical tanker	10	33	0.40%	176.9 to 553.2
Bulk carrier	3	3	0.06%	24.6
Ferry & ro-ro	41	25	0.98%	149.8 to 466.9
General cargo	4	2	0.05%	7.2
Liquefied gas tanker	18	0	1.07%	135.2
Service/tug/psv	31	9	0.13%	16.3
Cruise	0	18	4.82%	463.9 to 1,154.7
Vehicle	2	2	0.49%	31.1
Other	9	17	0.12%	16.4
Total	121	135	0.26%	1,273 to 3,015

LNG = liquefied natural gas, psv = platform supply vessel, ro-ro = roll on/roll off.
Source: DNV & ICCT Data from OIES

With the IMO 2020 sulfur ruling, bunker fuel markets are set to become fragmented: no longer is there a simple choice between a small number of hydrocarbon fuels. Now, the choice has expanded, and this has raised questions regarding fuel availability across all bunkering hubs.

Furthermore, and critically, it is important to add that the IMO 2020 sulfur rule will not be IMO's last. Currently, there are continuing discussions and meetings regarding a subsequent ruling regarding greenhouse gas (GHG) emissions. IMO ruling discussions and negotiations can go on for years and are of indefinite length. This creates considerable uncertainty for entities that are subject to IMO's rulings regarding managing compliance issues. Some entities have short investment time horizons of 5 years. Others have longer ones that go out to 30 years.

IMO's GHG ruling will seek significant reductions in emissions. While the timing of the final ruling is uncertain, already the IMO has committed to a 7-year evaluation plan, with a three-step approach: data collection, data analysis, and decision-making on what further measures may be required. The goal is to have an objective, transparent, and inclusive policy debate regarding the implementation of targeted emission limits.

Those maritime operating entities that have long-term horizons already are factoring future IMO rulings, especially with regard to GHG emissions, into their investment decisions. In these contexts, LNG becomes particularly advantaged; not only does it offer strict compliance with the IMO 2020 sulfur rule, as well as low nitrous oxide and particulate emissions, it has half the GHG emissions of petroleum-derived fuels. Lastly, LNG has operating cost advantages. For example, given that LNG is cleaner than fuel oil, engines and associated equipment will need less maintenance and last longer.

2-4-6. Additional LNG Considerations - Operations, Policy, and Case Studies

For LNG-fueled ocean-going vessels to be possible, existing ports need LNG bunkering capabilities. As previously mentioned, bunkering hubs are located at major ports along key maritime routes. Given that LNG has lower energy density, LNG-fueled vessels will either need larger tanks (thereby displacing valuable cargo-carrying capacity) or more bunkering hubs on long-haul routes.

There are two ways that LNG bunkering can take place: ship-to-ship fueling; and shore-to-ship. LNG bunkering vessels store LNG and travel to ships so that they can be refueled. This is particularly useful with large vessels such as containers that have difficulty maneuvering in tight ports or getting to shore-based fueling. Appendix Table 1 (LNG Bunkering Vessels – Current and Planned) lists all current and planned LNG bunkering vessels. Many of these listed were commissioned in 2017 and 2018.

The overwhelming majority of shore-to-ship fueling is in northern Europe. Thanks to longstanding Baltic and North Sea EmCA initiatives (see earlier discussion on EmCAs in this section) targeting not only sulfur oxide, but also nitrous oxide and particulate emissions, demand was increased for ships to have alternative fueling options, including LNG along with accompanying infrastructure. All coastal vessels voyaging within these EmCAs cannot deviate from these rigorous requirements.

TEN-T initiative

Furthermore, the EU has the Trans-European Transport Networks (TEN-T) initiative. Started in 1996, TEN-T seeks to coordinate, integrate, and improve all transportation systems within the EU, including ports and coastal waterways. With EU Directive 94 promulgated in 2014, all TEN-T core ports need to be equipped with some combination of LNG bunkering and shore power facilities by 2025. This would include not only ports within the Baltic and North Sea EmCAs, but also those along the Atlantic Coast and Mediterranean. In 2017, this directive was extended to include all EU Eastern Partnership countries.

The Singapore Initiative

In October 2016 at the Singapore International Bunkering Conference, representatives from the port authorities of seven major trading countries (Belgium, Japan, Norway, Netherlands, Korea, Singapore, US-Jacksonville, Florida) signed an MOU on the Development of LNG as a Marine Fuel. The goal of this MOU is to form a network of terminals to promote LNG bunkering, as well as to harmonise standards and specifications. This network has since been expanded to include French, Canadian, and Chinese port authorities.

2-4-7. Case Studies

Japan

Several factors favor Japan's ports and LNG facilities as key components to foster the development of LNG bunkering in Asia. First, Japan has 35 LNG terminals along its coasts, each of which has sizeable storage facilities. Second, as Japan's domestic LNG demand plateaus and possibly softens with the restart of its nuclear-powered plants, excess storage capacity can be directed to LNG bunkering uses. Third, Japan's geographic location, and, more specifically, the port of Keihin (comprised of Yokohama, Tokyo, and Kawasaki), is optimally situated on the North Pacific route between Asia and North America. Keihin is the first discharging port for westbound long-haul vessels, and the last loading port for eastbound ones. Furthermore, the port can accommodate a variety of vessel types and sizes. Last, weather conditions at Keihin are rarely adverse; therefore, the port is safely accessible year-round.

Already, a consortium comprised of Sumitomo Corporation, Uyeno Transtech, and Yokohama Kawasaki International Port are taking the initial steps to begin LNG bunkering operations. Via joint venture, this consortium is set to commission ship-to-ship LNG bunkering in Tokyo Bay (port of Keihin) projected to start in 2020. Established in May 2018, another joint venture made up of Chubu Electric Power, Toyota Tsusho, and NYK Line hopes similarly to start ship-to-ship LNG bunkering in 2020 at the port of Nagoya in the Chubu (Central) region of Japan.

China

In August 2018, China's Ministry of Transport issued a draft timetable for developing LNG bunkering. The timetable requested commentary from parties of interest including maritime operators and authorities, trade groups, and NOCs. The draft specified few details, but was aggressive in delineating specific milestones: by 2020, the Ministry hopes to have basic operating standards and the foundation for future infrastructure development in place; by 2025, it seeks to develop a comprehensive and technologically advanced water transportation for LNG.

The latter would include a minimum of 15% of new state-owned vessels and 10% of new vessels operating on major inland waterways. Under the initiative, key regions to be targeted are the Beijing-Tianjin-Hebei (Bohai waters) metropolitan region and the Yangtze River Delta. In addition, the plan seeks to establish two international LNG bunkering hubs. Also, in August 2018, China's Ministry of Finance issued directives granting tax exemptions to LNG-powered ships, as well as directing local authorities to reduce transit fees and prioritise port access for LNG-powered vessel operators. Combined, these regulations seek to establish a broad, commercially viable LNG bunkering market.

Most of the construction and retrofitting of LNG-fueled vessels has been financed by national gas companies such as China Gas Holdings, Kunlun Energy, CNOOC, and China Changjiang Bunker, a subsidiary of Sinopec. As of March 2018, China has 275 LNG-fueled ships, of which 160 are new builds and the rest are diesel retrofits. There are also 19 bunkering stations, of which three are operational. Developers of bunkering infrastructure include state-backed entities such as China Gas, CNOOC, and Hubei Energy Group, as well as private companies such as ENN and Jiangsu Haiqi Ganghua Gas Development. In April 2018, Hubei Energy Group announced plans to develop a RMB2.5 billion LNG storage and bunkering project on the Yangtze River with partial financing from the city of Zhijiang, Hubei province.

Singapore

In 2017, Singapore's Maritime and Ports Authority invested SGD12 million to accelerate LNG bunkering in its port. One part of the funding is allocated for new LNG bunkering vessels; the other is to facilitate investment in LNG-fueled ships. There are some conditions required by

Singapore for this funding, including being registered as a Singapore carrier; in return, Singapore is offering 5-year exemptions on port charges.

Fujairah

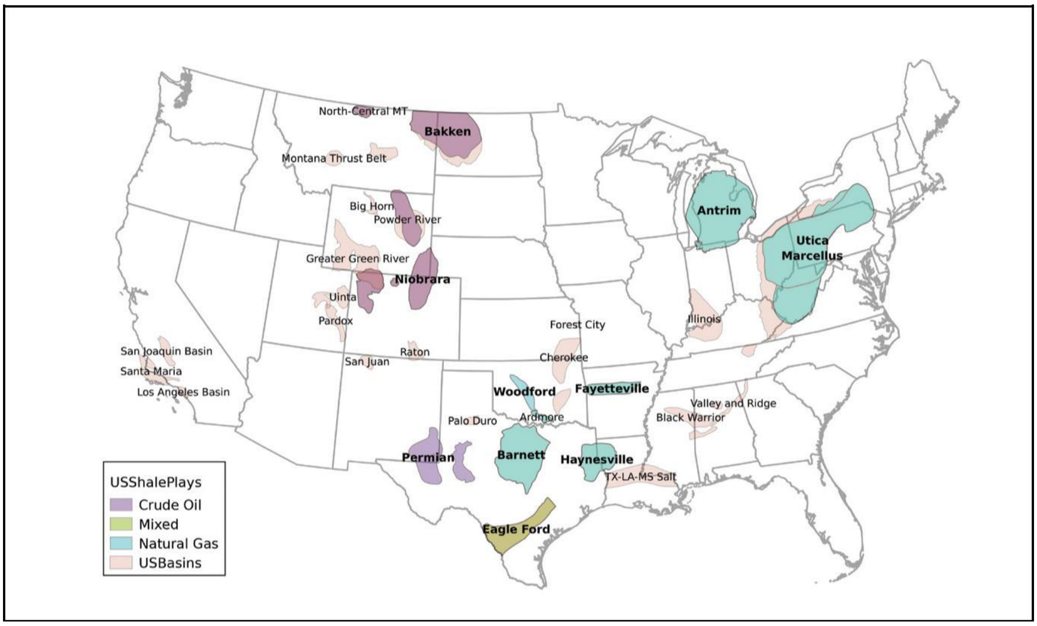
As the second-largest bunkering port after Singapore, Fujairah is planning to install LNG storage facilities with no set deadline. Located on the ocean side of the United Arab Emirates, Fujairah is strategically located on major maritime routes, making LNG storage facilities critical ahead of the IMO 2020 rule, as well as future IMO GHG-reducing bunkering initiatives.

Chapter 3
US LNG Supply Security

3-1. Pace and Outlook for US Upstream Natural Gas Development

The North American natural gas production platform is drawing upon a rapidly growing, low-cost reserve base. These reserves are prolific and distributed widely throughout the continental US. The distribution of these so-called tight (also known as unconventional or shale) gas plays are shown in Figure 3-1 below.

Figure 3-1. Main US Shale Basins and Plays



Source: US Energy Information Agency.

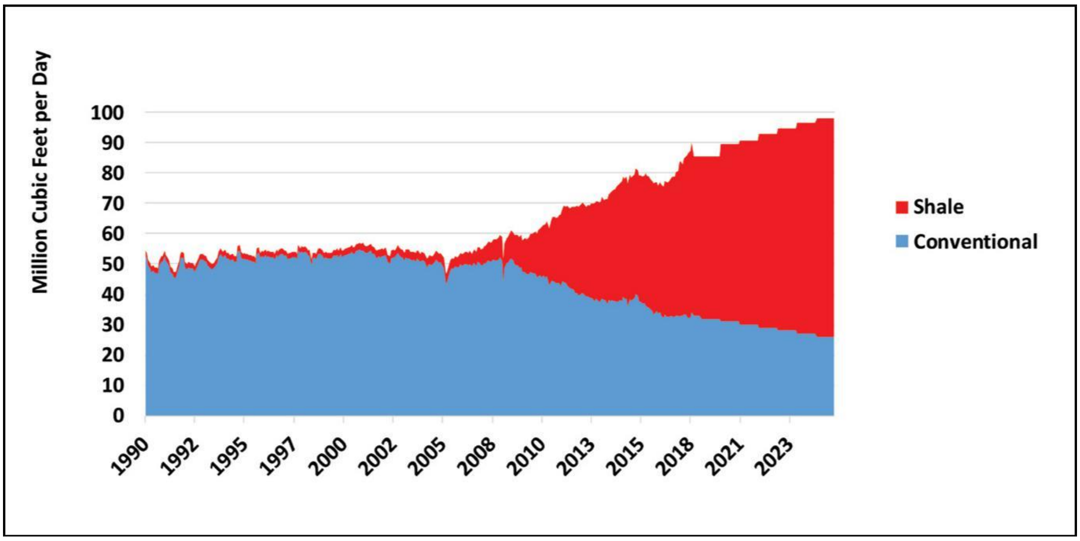
US natural gas reserves reached an initial peak of 201.7 Tcf in 1982, before declining to 164 Tcf in 1998. Since then, the US Energy Information Administration (EIA) estimates that domestic dry proved natural gas reserves have almost doubled, and are now estimated at 324 Tcf, most which are tied to additions from certified recoverable shale gas formations. However, reserves alone do not fully describe the potential size of the resource. According to the Potential Gas Committee, technically recoverable US natural gas resources are estimated to be 3,141 Tcf as of year-end 2016 (Millkov, 2017). When combined with EIA proved reserve estimates, the US future supply of natural gas represents the highest in the history of record keeping for US reserves.

In EIA's 2018 Annual Energy Outlook, US dry natural gas production is expected to increase through 2050 across many alternative assumptions. If there is no major change in US law or policies, US natural gas production is likely to rise in 2018 from approximately 80 Bcf/d to over 100 Bcf/d by 2022. These numbers are after processing and hence lower than wellhead production. More importantly, EIA forecasts natural gas production after 2020 growing faster than consumption in virtually all scenarios. EIA's high resource and technology case expects US natural gas production to reach over 150 Bcf/d by 2050. Even in a more constrained outlook, an expansion of 40 Bcf/d (14.6 Tcf/yr) by 2040, or 50% above current production, is well within the potential of the US oil and gas resource base.

As gas production continues to increase, the US is projected to become the third-largest LNG exporter in the world by 2022, surpassing Malaysia and remaining behind only Australia and Qatar. According to EIA data, by that year, the US is forecasted to generate almost 40% of the rise in global gas output, which could position LNG exports to supply over a quarter of the global LNG demand. However, the projected LNG exports may vary significantly depending on several factors like oil prices, economic growth, international pipeline trade, and market share of natural gas versus other fuels.

The size of the unconventional natural gas resource base, combined with continuing emergence of new extraction technologies and improved efficiencies in drilling operations, all point to significant production growth in the coming decades. Natural gas production in the US is more likely to be limited by inadequate demand than a lack of advances in technology or growth of the resource base. Figure 3-2 shows the rapid growth in US natural gas production since the shale discoveries in 1990 and the likely growth through 2025.

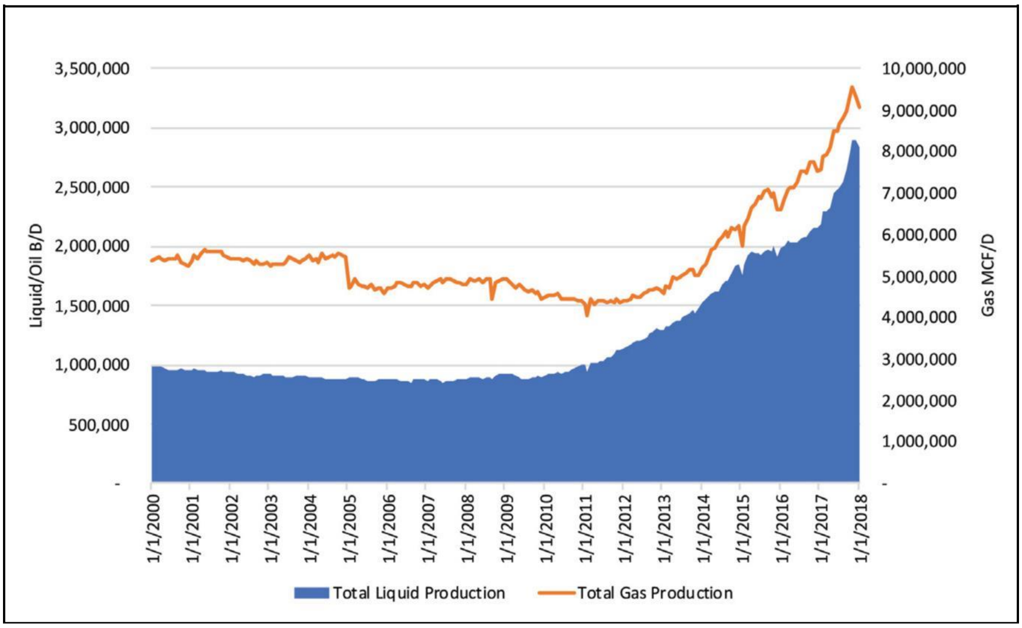
Figure 3-2. Natural Gas Production in the US, 1990 to 2018 (Estimated) and Forecast through 2025



Source: US Energy Information Agency.

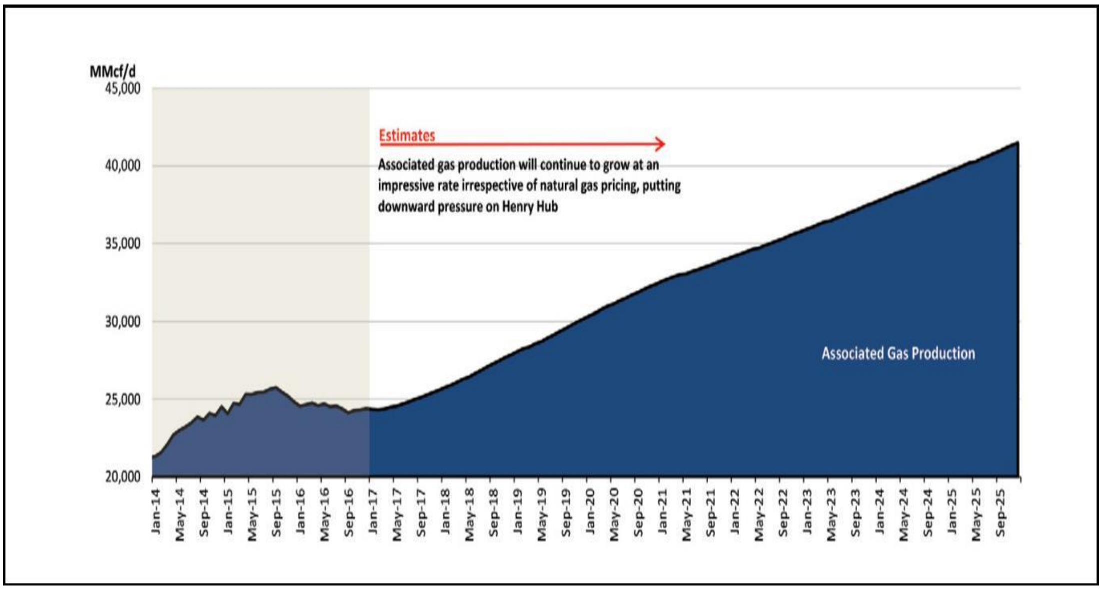
Another important feature of the US natural gas extraction process is the growing volumes of associated gas. This is natural gas production that flows up the well bore during the production of crude oil from shale formations. Associated gas production is a common occurrence in the oil production plays throughout the Permian Basin in Texas and New Mexico, and is a by-product of expanding oil production in this geologic formation. As shown in Figures 3-3 and 3-4, natural gas production in the Permian Basin closely tracks expanded oil production throughout the play.

Figure 3-3. Permian Basin Oil and Natural Gas Production



Source: Trisha Curtis, EPRINC Fellow and Founder, PetroNerds. Presentation at EPRINC Natural Gas Workshop, Washington, DC, 19 April 2018.

Figure 3-4. US Associated Dry Natural Gas Production



Source: US Energy Information Agency, Raymond James Research.

3-2. Prospects for Sustained Low Henry Hub Prices for Export Markets

As shown in Figures 3-3 and 3-4, approximately half of the natural gas produced in the Permian Basin is classified as associated gas. This is very low-cost natural gas, which most producers are willing to sell at whatever price needed to move it to market. The primary reason is that a failure to find a market outlet for the gas would require producers to flare the resource at the well site to maintain oil production, an outcome that state regulators are not likely to permit.

The recent expansion of US natural gas production, combined with continued investment and development of new production, points to sufficient supplies to limit substantial increases in natural gas prices both for the domestic market and as a feedstock for processing into LNG. There is growing evidence that the US is not reserve-limited in terms of the natural gas resource, but that future cost pressures on natural gas are more likely to come from rising costs of production from deploying and operating drilling rigs. Analysis from Vello Kuuskraa, shown in Table 3-1, shows that, in the case of the Haynesville play in Texas, even with rising drilling costs (day rate and completion costs), improvements in estimated ultimate recovery and hydraulic fracturing performance protect against increases in development break-even costs at current levels through 2025. This assessment reinforces the outlook that the US natural gas production platform can expand without substantial per unit cost increases. US major natural gas production plays are shown in Figure 3-5.

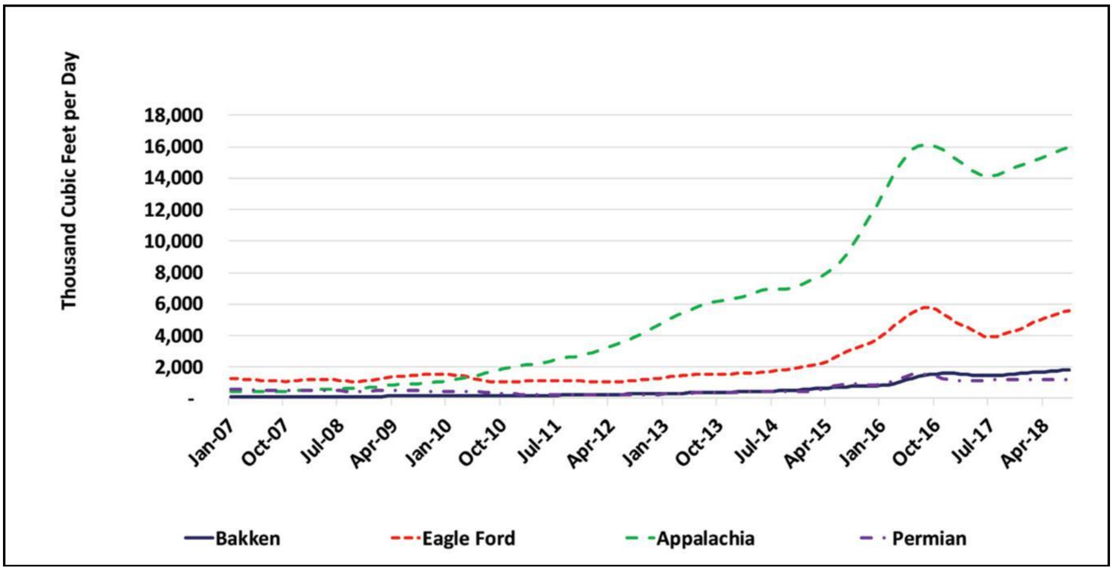
Table 3-1. Drilling Efficiencies in Natural Gas Production in the Haynesville Play

	Actual 2017 (@US$50/Bbl)	**Projected 2025 (@US$65/Bbl)**
Lateral Length	7,400	8,500
1. Well Drilling		
Days to Drill	30	21
Rig Day-Rate (US$/day)	15,000	23,000
Total Well Drilling Costs (US$M)	**3,400**	**3,710**
2. Well Completion		
Frac Stages	25	33
Frac Cost (US$/Stage)	60,000	79,000
Total Completion Costs (US$'000)	**5,100**	**6,430**
Total Well D&C Cost (US$'000)	**8,500**	**10,140**
Gross EUR/Well (Bcf)	**18.4**	**21.2**
'Break-Even' Costs (US$/Net Mcf)	**2.50**	**2.60**

Note: D&C = drilling and completion, EUR = estimated ultimate recovery
Source: Vello Kuuskraa, Advanced Resources International.
Presentation at EPRINC Natural Gas Workshop,
Washington, DC, 19 April 2018.

Figure 3-5. US Major Plays: Natural Gas Production per Rig

(Thousand cubic feet per day)



Source: US Energy Information Agency.

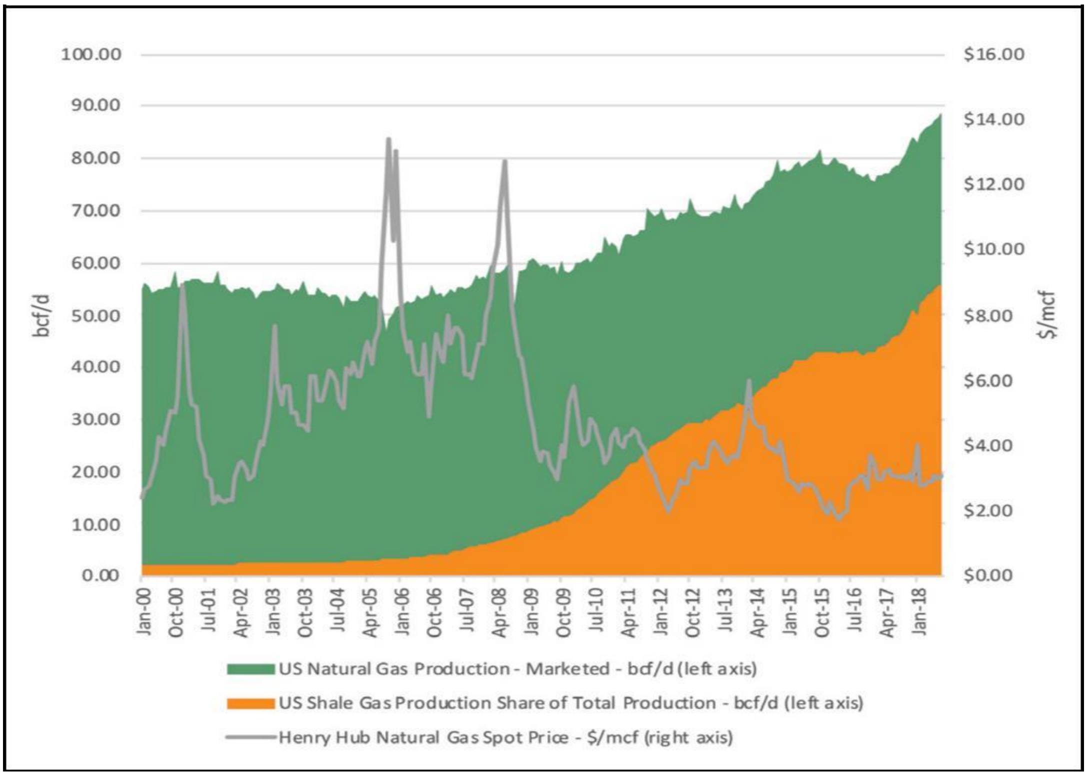
An often overlooked but important feature of US natural gas production is the high degree of operational efficiency and liquidity of service providers across the entire value chain. Although not entirely unique, the development of US natural gas resources is distributed amongst many players, subject to constant cost reductions and technology improvements, and rapid infrastructure expansion (although delays have occurred in getting essential transportation infrastructure in place). Additionally, the US natural gas market is segmented across its supply chain. Exploration and production entities are generally separate from distribution (pipeline LNG) and storage operations, and the latter is separate from utilities that make deliveries to final points of consumption. These industrial features keep the US natural gas market active and competitive, which eventually benefits Asian natural gas markets through the export of competitive LNG cargoes.

Lastly, the US market is characterised by widespread transparency in the reporting of gas pipeline capacity utilisation, tariffs, and prices at market hubs. There is also broad liquidity in both physical and financial markets. This is due in part to the consistent and coherent regulation and enforcement from government agencies such as the Federal Energy Regulatory Commission (FERC), the Commodity Futures Trading Commission (CFTC), and the

Securities and Exchange Commission (SEC). These forces are likely to keep the long-term price of US natural gas based at its primary trading location, Henry Hub.[4]

The analysis of the Eagle Ford cost structure is reinforced by Figure 3-6 below, which shows that the US natural gas production has continued to expand even as prices declined to US$2/Mcf in late 2015. There was some flattening and even a mild downturn in US natural gas production from the middle of 2015 through late 2016. But this was tied to delays in moving gas supplies out of the Marcellus to domestic processing centres and export markets. Although prices have recovered somewhat and are now approximately US$3/Mcf for 2017, shale gas output will continue to expand and take a growing percentage of total US natural gas production.

Figure 3-6. Monthly US Natural Gas Production (LHS) vs Henry Hub Price (RHS)



Source: US Energy Information Agency.

[4] Henry Hub pipeline is in Erath, Louisiana and is the pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX). The NYMEX contract for deliveries at Henry Hub began trading in 1990 and is deliverable 18 months in the future. The settlement prices at Henry Hub are used as benchmarks for the entire North American natural gas market and parts of the global liquid natural gas market. Henry Hub is an important market clearing pricing concept because it is based on actual supply and demand of natural gas as a stand-alone commodity.

3-3. US Regulatory Outlook for LNG Exports

It should also be noted that, under the policies of the Trump administration, the US federal government through the Department of Interior is now expanding oil and gas development on public lands on an accelerated schedule. In an oil and gas lease sale held in New Mexico in the first week of September 2018, the federal government collected nearly US$1 billion for the rights to develop the oil and gas resources on public land in the Permian Basin. These are very large bid values for onshore plays. The lease sale covered over 50,000 acres prospective for oil and gas shale development. One bid alone for 1,240 acres in Eddy County brought in more than US$100 million. The lease demonstrates that development of shale reserves on federal lands will supplement US oil and gas production.

3-3-1. US Department of Energy

Many local, state, and federal agencies are involved in reviews and permit approvals to produce natural gas, distribute it to processing centres, and build and operate LNG export facilities. Two federal agencies dominate the review process: the US Department of Energy (DOE) and FERC.

DOE's Office of Fossil Energy (DOE/FE) is responsible for authorising exports of domestically produced natural gas under US law. DOE/FE reviews applications to export natural gas to countries with which the US has not entered into a free trade agreement (FTA). As of 21 June 2018, DOE/FE issued 29 final long-term authorisations to export LNG and compressed natural gas to non-FTA countries in a cumulative volume totaling 21.35 Bcf/d. These authorisations have a term of 20 years, with additional time provided for LNG export operations to commence. Some stakeholders have raised concerns that, under the DOE approval process, LNG exports face a revocation risk, which can raise the cost of financing new projects and limit market access.

In response to buyer concerns over revocation risk, DOE Deputy Secretary Dan Brouillette publicly reinforced DOE/FE policy on the stability of US LNG exports at the Annual LNG Producer Consumer Conference in Tokyo in 2017. In a public statement in the US Federal Register (21 June 2018), DOE/FE pointed out that it has never rescinded a long-term non-FTA export authorisation for any reason, unless so requested by the exporter or if the exporter abandons efforts to develop the project. Further, DOE has repeatedly stated that it has no record of ever having vacated or rescinded an authorisation to import or export natural gas once approval has been granted over the objections of the authorisation holder. The one order vacated was strictly due to the exporter's inaction in proceeding with the project.

3-3-2. Federal Economic Regulatory Commission

There have been concerns raised by industry experts and policy makers that the approval process for the siting and operation of new LNG export facilities is taking too long and delaying construction. In response, on 31 August 2018 FERC issued a Schedule for Environmental Review (SER) to 10 new LNG export projects, and reissued SERs for two others (Driftwood and Jordan Cove). Between April 2012 and December 2016, FERC issued 12 certificates to export facilities. Since President Trump took office in January 2017, FERC has issued no orders for new LNG export facilities, and had issued SERs for only two projects: Venture Global's Calcasieu Pass, and Tellurian's Driftwood LNG. Of those, FERC has only issued a draft environmental impact statement to Calcasieu Pass. FERC's stalled LNG export facility review process does not directly follow the Trump administration's stated objective of accelerating energy infrastructure reviews. In June, Chairman Kevin McIntyre acknowledged to Congressional committees that the Commission was having difficulty keeping up with the enormous workload requirements. However, since August 2018, FERC has made progress in resolving this slowdown.

In September 2018, FERC released a new MOU with the Pipeline and Hazardous Materials Safety Administration, which is assuming review responsibilities for the design and operation of feedstock pipelines and LNG operations. This should relieve some of FERC's workload and improve the timing of construction permits.

FERC is also preparing full environmental impact statements for the eight new projects that received SERs on August 31 (Port Arthur, Texas LNG, Jacksonville Eagle, Gulf LNG, Annova LNG, Rio Grande LNG, Venture Global Plaquemines LNG, and Jordan Cove). Driftwood and Alaska LNG received revised SERs. The new SERs indicate that FERC is attempting to adhere to a 4-month window between draft and final environmental impact statements, a shorter interval than in the past. A further 10 projects could be approved by the summer of 2019. Table 3-2 shows the FERC review schedule for pending LNG projects.

Table 3-2. New FERC Review Schedule for Pending LNG Projects

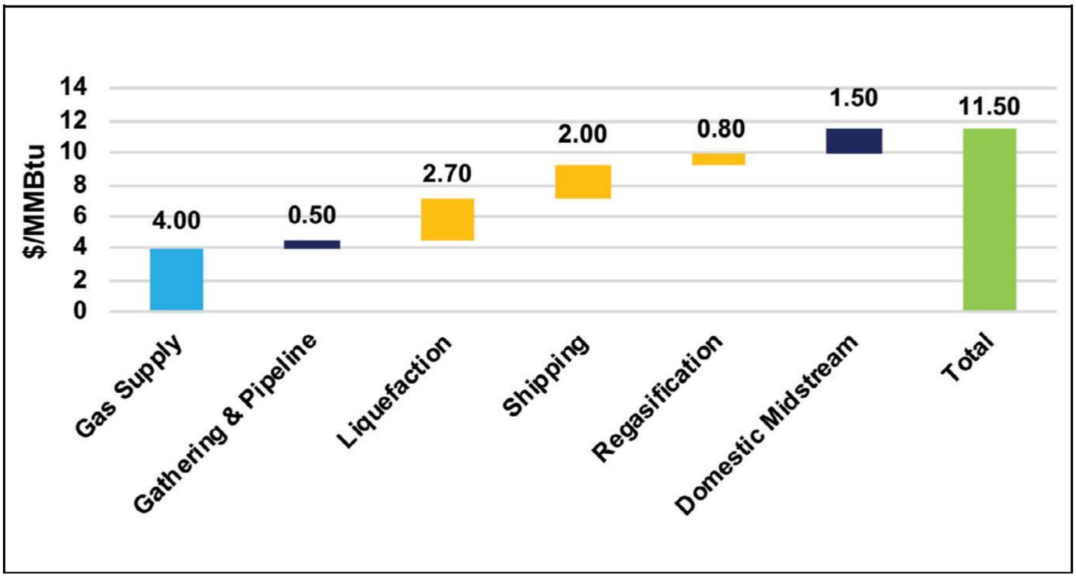
Project	Date When Project Will Be Ready for Final Approval
Transco NE Supply Enhancement	17 September 2018
Calcasieu Pass	26 October 2018
Driftwood LNG	18 January 2019
Port Arthur LNG and PA Pipeline	31 January 2019
Texas LNG	15 March 2019
Eagle LNG Partners Jacksonville LLC	12 April 2019
Gulf LNG	17 April 2019
Annova LNG	19 April 2019
Rio Grande LNG	26 April 2019
Venture Global Plaquemines LNG	3 May 2019
Jordan Cove, Pacific Connector	30 August 2019
Alaska LNG	8 November 2019

FERC = US Federal Energy Regulatory Commission, LNG = liquefied natural gas.
Source: FERC as of 30 September 2018.

3-3-3. Cost Competitiveness of US LNG Exports

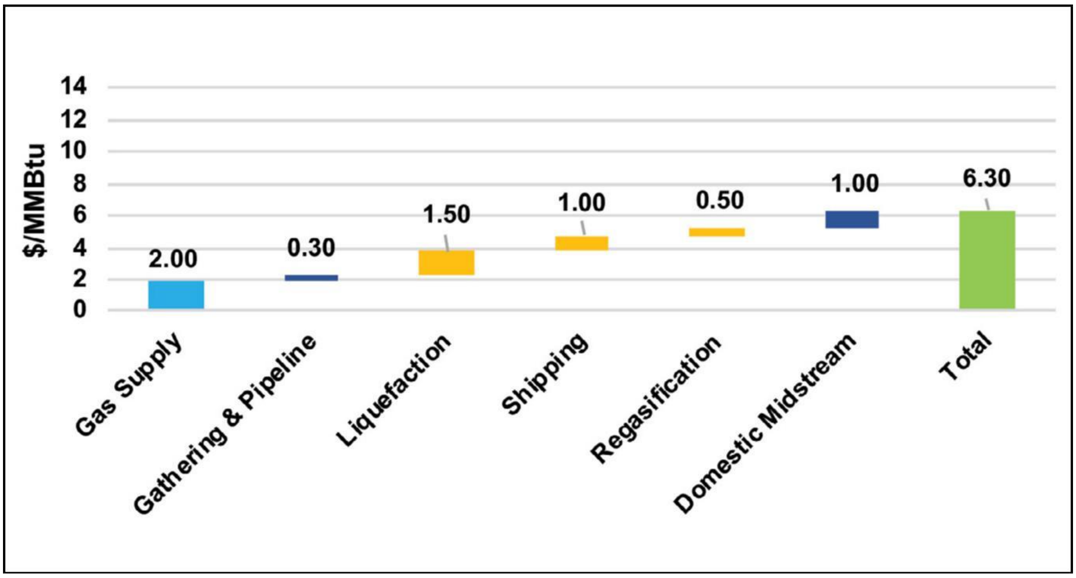
Figures 3-7 and 3-8 below capture the range of uncertainty regarding the competitive position of US LNG exports delivered to Asian markets from facilities via the Gulf of Mexico. As the figures show, the cost of delivered US LNG to Asian markets will be driven by both the cost of construction and operation of liquefaction facilities and the availability of low-cost feedstock. The vast scale of the US natural gas reserve base, combined with rising volumes of associated gas, increase the likelihood that US feedstock costs will remain very low across a wide range of export volumes. Challenges remain on sustaining a timely build-out of domestic midstream infrastructure in the US and permits for construction on new liquefaction plants, but considerable progress has been made in implementing a more timely and predictable approval process as part of the administration’s energy policy. Advances in project design and technological innovations can keep liquefaction and shipping costs low and US LNG exporters are well positioned to sustain a cost structure that is competitive for Asian markets.

Figure 3-7. Asia-Delivered LNG: Low-Cost Structure Scenario



LNG = liquefied natural gas.
Source: Bloomberg Data.

Figure 3-8. Asia-Delivered LNG: High-Cost Structure Scenario



LNG = liquefied natural gas.
Source: Bloomberg Data.

3-4. Panama Canal

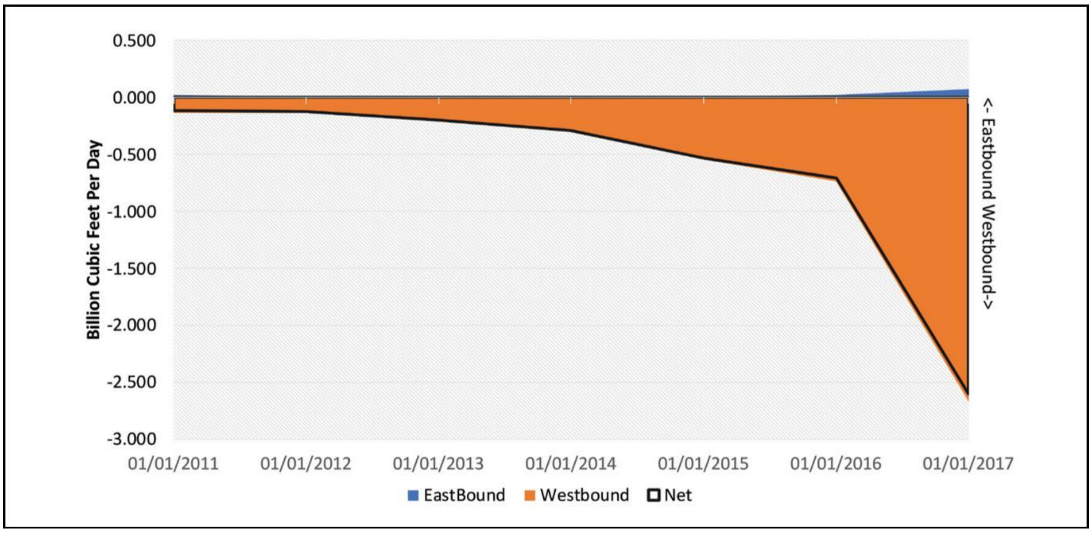
The Panama Canal represents a potential transit chokepoint on the movement of LNG from the East Coast and Gulf Coast of the US to selected Asian destinations. The importance of this emerging LNG trade route has increased focus on the Panama Canal by both US LNG producers and Asian countries hoping to meet rising demand with US LNG exports. Expectations on the Panama Canal's capacity to efficiently permit transit of growing volumes of LNG shipments from the US have been subject to misinformation and scheduling practices that have created the appearance that it is a severe constraint on Gulf Coast LNG shipments to Asia. This prompted the government-run Panama Canal Authority (ACP) to adjust their operating policies to expand annual LNG transit capacity.

This is not the first attempt by the ACP to increase the Panama Canal's capacities since lock size is the limiting factor for ship size (the locks are only 34m wide). On 26 June 2016, a wider third lane of locks that had taken 9 years to build opened and can now handle so-called Neopanamax vessels. Such vessels can be up to 294.1 meters long, with a beam of 32.3 meters and draught of 12.04 meters, with LNG carrying capacity up to 3.9 billion cubic feet (Bcf).

The expansion significantly affected LNG trade as it reduced both transportation costs and travel time for LNG shipments and provided additional access to previously regionalised LNG markets (EIA, 2016). As evidenced in Figure 3-9, LNG transit volumes through the Panama Canal remained relatively low until 2017, when a steep spike in volume occurred, specifically westbound towards the Pacific Ocean. This increase is clearly related to the Panama Canal's expanding in 2016, but it was not as prepared to meet the demands of the LNG industry. For reference, Figure 3-10 below shows the transit volumes of the Suez Canal, a much more mature LNG transit route with a much steadier curve. Even so, the spike in Figure 3-9 indicates that the LNG industry pushed the Panama Canal and the ACP to respond to demand requirements.

Figure 3-9. Panama Canal LNG Transit: January 2011 to January 2017

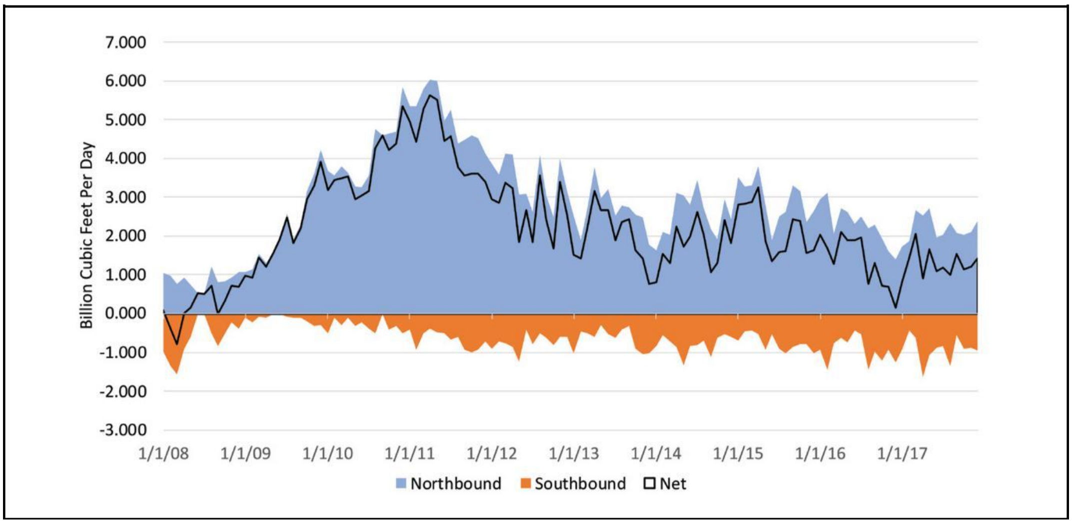
(Billion cubic feet per day)



LNG = liquefied natural gas.

Source: Annual Panama Canal data.

Figure 3-10. Suez Canal LNG Transit: January 2008 to December 2017



LNG = liquefied natural gas.

Source: Monthly Suez Canal data.

The ACP has recognised that the expansion was insufficient to meet transit requirements for LNG shipments to Asia without some operational changes. Recently, ACP released several changes to the regulations surrounding LNG shipping to accommodate the increase in demand and to mitigate the effects of some undesirable practices of some LNG carriers. One major issue, as the ACP puts it in their *Advisory to Shipping No. A-29-2018,* is 'the current practice by some LNG customers of acquiring booking slots during the first period competition, to the point where these slots are nearly sold out up to 365 days in advance, while in reality these slots are only used on average 60% of the time' (Canal de Panama, 2018). Those booking slots are very valuable because, until recently, the ACP limited the number of LNG vessels to one per day in one direction. By purchasing booking slots that they did not intend to use, other nations could limit the amount of US LNG that could reach Asia, tightening the bottleneck in Panama. This would, of course, keep LNG prices from dropping due to increased supply, and limit the amount of LNG that could be sold west from the Gulf Coast.

On 1 October 2018, the policy changes laid out by the ACP took effect. Several were specifically designed to change this sort of behaviour. The text from the ACP's *Advisory to Shipping No. A-29-2018* that addresses the practice of buying booking slots without intending to use them reads:

> *This practice is detrimental since it creates the perception that the Panama Canal does not have the capacity to handle the actual LNG demand, affecting not only the best interests of the Panama Canal Authority (ACP) and the LNG industry, but of other customers as well. These modifications will allow the Panama Canal to better handle the present and expected demand for LNG vessel transit slots by providing the certainty and flexibility required by the LNG market segment.* (Canal de Panama, 2018)

Beginning on 1 October 2018, some navigational restrictions were lifted that enable several LNG vessels to inhabit Gatun Lake. That means that the Panama Canal will be able to transit LNG vessels in different directions on the same day, contrary to recent practice. As a result, the maximum number of LNG vessels has been increased from one to two per day, either two northbound or one northbound and one southbound.

According to recent communications with the ACP via the Embassy of Panama in Washington, DC, 'the beam of vessels allowed to transit at night has been increased, depending on the type (Advisory to Shipping A-31-2018). For example, container vessels of up to 335.28m length overall will be able to transit at night if their beam is less than or equal to 43.28m. This will help liberate some slots during daytime, improving Canal capacity overall.' This method of increasing the LNG transit capacity is a direct response to frustration from US LNG transport companies, who insisted that safety regulations limiting nighttime operations of their vessels in the Panama Canal were too strict.

Another major regulatory change made by the ACP that will have a direct effect on the Asian LNG market was made in the way their slot booking process works. A special booking period 1a in between Booking Periods 1 and 2 was created for LNG vessels 80 to 22 days before the transit date in which LNG vessels specifically will have one slot allocated to them (Canal de Panama, 2018). That time frame is also important, as, under the previous system, Booking Period 1 was sold 365 days before the transit date, which was a limiting factor on the flexibility of LNG and a variable that hindered the liquidity of the spot market.

Finally, cancellation of slots for LNG vessels will incur an additional fee on top of cancellation fee. LNG vessels that do not cancel and fail to arrive by 0600 on their booked date will be charged a cancellation fee and an additional fee of US$35,000. Also, if the vessel fails to arrive within 5 days of the booked date, the customer who booked the slot, 'will be penalized with the reduction of 0.5 transits in the transit portion of the customers ranking' (Canal de Panama, 2018), which may affect their ability to win future slots. To avoid accidentally penalising customers who are missing their booked slot or were late for valid reasons, the ACP has added that the above penalties will not apply if the, 'vessel's late arrival or cancellation of the reservation is due to a medical or humanitarian emergency, fortuitous event or force majeure' (Canal de Panama, 2018).

It is difficult to precisely estimate the shipping volume capacity expansion from the regulatory changes enacted by the ACP. What is clear is that Panama has addressed the concerns of LNG customers, and has eliminated both unfair practices and physical limitations of their vital portion of the LNG transportation infrastructure. LNG shippers and buyers should continue to engage the ACP on a regular basis so that operations can be adjusted to shifting patterns of LNG transit requirements.

Chapter 4
Policy Recommendations

4-1. Market Creation

4-1-1. Acceleration of Destination Restriction Removal

After the Japan Fair Trade Commission (JFTC) study was published, destination restrictions are being removed from new long-term contracts. The destination clause in the existing contract, however, seems to have remained, although the JFTC study urges the Japanese LNG buyers to renegotiate the clause in the existing contract. This is because the destination restriction is still regarded as a bargaining chip for LNG sellers and the removal of the destination restriction accompanies the revision of the other contractual conditions including price. Some buyers prefer to maintain a favorable relationship with sellers and are not very willing to discuss this issue with sellers. An additional driver is needed to enforce the JFTC's suggestion on the renegotiation of the destination restriction.

In Japan, it is desired that JFTC will conduct a follow-up survey with legal authority to ensure the destination restriction is removed from existing long-term contracts as well. Anti-monopoly authorities in other countries, including the US Fair Trade Commission, are also recommended to study this practice and provide a view on this issue.

4-1-2. Development of Reliable LNG Price Benchmark

An LNG price benchmark is a missing link of beneficial active spot trades and market liquidity and transparency in Asia. Buyers and sellers require full transparency in the fundamentals of supply and demand, without which the LNG market cannot fully expand. Existing pricing methods that are linked to the crude oil price are not rational since most of the LNG demand growth in the future will be observed in the power sector, where LNG usually competes with coal and renewable energy. The volume of trading at the existing price benchmark is growing, but it is not reliable enough to gain confidence from all market participants.

An increase of flexible LNG supply through removal of the destination restrictions in long-term contracts, as well as investment in new liquefaction capacity to supply destination-free LNG cargoes, will help to solve this problem. In addition, an initiative by a large market player to pick up a specific benchmark for their term contract price formula may be required to create a representative price benchmark, just as Centrica picked up the UK National Balancing Point as a price benchmark for their term contract. Also, market participants are encouraged to participate in spot-trading platforms and disclose the price level for which they transact a particular spot cargo. An established benchmark will enhance both market liquidity and supply security.

4-2. Demand Side

4-2-1. Assistance to Private Investment in LNG Value Chain (Downstream)

The development of LNG import facilities (re-gasification, gas distribution pipelines, power plants) requires billions of dollars in capital outlay; this can be tied up for as much as a decade before any revenue is realised. LNG projects also face important risks across the entire value chain; feedstock costs can rise, interruptions are possible in feedstock delivery systems, regulatory programmes can impose new requirements on both exporters and importers, government policy can change, and financial performance of an LNG project can be disrupted by price changes and demand shifts.

Addressing these risks can enhance predictability and bring more LNG projects to FID. Assistance from export credit agencies, insurance for political and non-performance risks can address important obstacles to bring projects to FID. Continuing capacity building for regulatory authorities and development agencies remains essential. Steady efforts to assist private investment should be undertaken by revising the conditions for financial assistance provided by ECAs in Japan and in the US. Congressional review is ongoing to consolidate the US ECAs so they can more effectively assist private investments in new Indo-Pacific energy infrastructure projects.

4-2-2. Engagement with Emerging Buyers

As the presence of emerging LNG buyers increases, a closer communication and cooperation with them has become more important. Because the demand in these countries tends to be more unstable, sharing market status information or demand patterns will benefit all players in the LNG market. Emerging buyers will also find it useful to exchange views on how to develop LNG markets with preceding importers.

Such a collaboration will also improve the natural gas supply security of LNG importers. Unlike the international oil market, there is no equivalent organisation or system like the International Energy Agency's emergency response framework. Communicating and discussing the latest demand and supply balance of the international LNG market, the outlook of demand and infrastructure development, and supply security measures such as inventory holding or developing storage facilities will enhance emergency preparedness.

Building a new cooperative framework from scratch will require huge resources. Using an existing framework such as ASEAN+3, APEC, or the East Asia Summit group will be an effective solution, since their members cover most of the major LNG buyers in Asia. To augment such a framework, the annual LNG Producer–Consumer Conference held in Japan will also deepen gas supply security, since it is the platform where policy makers and government officials regularly convene and can discuss cooperative actions. Adding a new role and objective as the platform of Asian LNG supply security discussions to the Producer–Consumer Conference will bring a valuable opportunity for every stakeholder in the global LNG market to discuss supply security and ensure sound development of the Asian market.

4-2-3. Development of a Fast-Tracking Tool for Project Development

Providing a model project structure and required documents will facilitate infrastructure development, since many Asian emerging countries have limited or no experience of LNG imports or gas-to-power projects. This is particularly the case in an LNG-based gas-to-power project as it contains various value chains from LNG procurements to construction and installment of a receiving terminal and gas-fired power plant. It usually requires a long-term, thorough negotiation to determine the structure of the project, especially who undertakes what responsibility and what kind of risks are endemic. If there were a model project structure that the host country and project developer could refer to, it would be more efficient to discuss and determine the structure.

In many Asian emerging LNG importing countries, laws and regulations for import and utilisation have not been well developed. Such model documents will be a useful reference point for each stakeholder.

Ideally, the project structure would be fully tailor-made to reflect the local conditions and requirements. However, it is also true that such a tailor-made approach requires a far longer time for the project to be realised. There is an acute and urgent need for energy and power supply in emerging Asian countries, and using the model project will be an efficient solution to fast-track gas-to-power projects. Multilateral development banks such as the World Bank or the Asian Development Bank will lead the formulation process based on their vast experience and deep expertise.

4-2-4. Preparation for the Emergence of LNG Bunkering Demand

As LNG bunkering advances globally, there is the potential that bunker fuel markets will become fragmented. Where maritime operators had limited fuel type choices but ubiquitous supply availability, there now is the possibility of the inverse: many different fuel choices with gaps in coverage across the globe. For LNG bunkering to succeed, coordination is necessary.

Operators and other maritime participants, especially those with long investment horizons, need to be vigilant: the IMO 2020 sulfur directive is not the last rulemaking that it will undertake. Already, there are discussions regarding GHG emissions, and this will impact fuel choices. This will critically advantage LNG, but primarily in the longer term.

For LNG bunkering to develop in Asia, the EU, through its TEN-T initiative, offers a model template. Each of TEN-T's efforts are coordinated on many fronts, with clear requirements and timetables comprehensively covering operating and financial parameters.

4-3. Supply Side

4-3-1. Assistance to Private Investment in LNG Value Chains (Upstream)

As in downstream, a policy measure to assist private investments in upstream and liquefaction is also critical. As with the case of investments in downstream sectors, assistance from export credit agencies in Japan and the US will continue to play a vital role.

For US exporters, a timely and predictable process for evaluating and issuing permits for both building natural gas pipelines to move feedstock to export facilities, as well as permits for liquefaction facilities, is essential. Regulatory risks can be a major impediment to reaching FID. In this respect, US regulatory agencies are making progress. DOE has developed a timely, predictable, and informed process for issuing LNG export permits. The permit process for pipelines and LNG export facilities as administered by FERC has suffered from a growing workload, but recent reforms offer considerable promise. Continued attention to improving the FERC process is warranted.

New investment structures can also enhance predictability. Tellurian's Driftwood LNG project has built an integrated investment programme that includes upstream assets, pipelines, and a liquefaction facility on the US Gulf Coast. In this financial structure, an LNG investor can now lock in the cost of the entire value chain at an equivalent of US$3/Mcf. Other investment structures may also emerge to address other risks from LNG development.

4-3-2. Innovative Investment Plan for Upstream Investments

Ensuring sustained investments in the upstream sector is a vital condition of natural gas supply security. Demand in emerging LNG importers is growing at an unexpected speed, and lack of timely investments will cause a supply crunch and intolerable price hikes, both of which will eventually harm the interests of buyers and sellers alike.

The widening mismatch of interests between buyers and sellers has been often cited as a reason for stalled FID in the last few years. Market players have not been able to adapt to a new model of risk allocation under the new LNG market reality, with a larger number of emerging LNG buyers and growing demand for shorter and flexible supply. There is a dire need for innovative ideas to break the current FID deadlock. A packaged investment for wellhead natural gas production, pipeline, and liquefaction plant construction such as Tellurian's equity model may be one such idea. Both buyers and sellers are required to consider something different to proceed with the further expansion of the Asian LNG market.

4-3-3. Collaboration to Avoid the Panama Canal Bottleneck

ACP recognises the potential capacity problems of the Panama Canal for LNG tanker passage in the future and has already taken several steps to avoid such bottlenecks. However, it is still uncertain if its actions are enough to accommodate the rapid expansion of US LNG exports given the large seasonal demand fluctuations. The US, Japan, and other LNG importing countries will minimise this risk by active information sharing and policy discussions.

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Appendix

Additional Exhibits for Bunkering

LNG Bunkering Locations – Current and Planned – Part 1

Port	Type	Capacity	Operator	Status	Start Date	Comments
Dunkerque	Ship-to-Ship		Total Marine - Fuels	Planned	2020?	Infrastructure being developed to support Ship-to-Ship LNG bunkering of CMA-CGM containerships by Total Marine Fuels. Plan to adapt existing LNG jetty and then construction of dedicated LNG jetty for small-scale LNG operation.
Marseille	Truck-to-Ship, Ship-to-Ship planned	TBD	Molgas	Operational	January 2018	Currently, Truck-to-Ship for weekly call of Aida Perla cruise ship. Cold ironing operation. Ship-to-Ship under negotiation for LNG fueled cruise ships and ferries to Corsica.
Le Havre	Truck-to-Ship	TBD	Shell	Operational	May 2016	Weekly call of Aida Prima cruise ship. Cold ironing operation.
Amsterdam	Truck-to-Ship since 2013; Ship-to-Ship planned for Q4 2018	TBD	TBD	Operational	2013	Port of Amsterdam has an annual bunker fuel throughput of approximately 2.5 million tonnes per annum. Production of bio-LNG planned for the port in the near future.
Vancouver	Truck-to-Ship	78 cum/ hour delivery per truck; multiple truck capabilities	Fortis BC	Operational		FortisBC provides Truck-to-Ship bunkering to BC Ferries. LNG is supplied from Fortis BC's Mount Hayes liquefaction plant.
Vancouver	Truck-to-Ship	78 cum/ hour delivery per truck; multiple truck capabilities	Fortis BC	Operational		FortisBC provides Truck-to-Ship bunkering to BC Ferries. LNG is supplied from Fortis BC's Tilbury liquefaction plant.

Vancouver	Truck-to-ship	78 cum/ hour delivery per truck; multiple truck capabilities	Fortis BC	Operational		Fortis BC truck-to-ship bunkering of Seaspan ferries. LNG supplied from Fortis BC's Tilbury liquefaction plant.
Bilbao	Ship-to-Ship	Bunkering vessel capacity of 600 cum	ITSAS Gas, part owned by Vasco de la Energía	Operational	February 2018	LNG is sourced from the Bay of Biscay Gas regasification plant owned by Enagás and the EVE. Dock and terminal have been remodeled to facilitate the loading of LNG for the ITSAS Gas vessel Pilot Ship-to-Ship transfer of approximately 90 cum of LNG from the Oizmendi to the cement ship M.V. Ireland moored in the port of Bilbao completed in early February 2018.
Isle of Grain	TBC	TBC	Grain LNG	Proposed	2019	Grain LNG is looking at developing break-bulk facilities for smaller LNG carriers and LNG bunkering.
Chubu region	TBC	TBC	Toyota Tsusho / NYK Line	Planned	TBC	NYK Line is in joint discussions with 'K' Line, Chubu Electric Power Co, and Toyota Tsusho Corporation to develop a new business to supply LNG bunkers to ships in the Chubu region (January 2018).

Source: SEA¥LNG

LNG Bunkering Locations – Current and Planned – Part 2

Port	Type	Capacity	Operator	Status	Start Date	Comments
Valencia	Land-based initially	TBC	Gas Natural Fenosa	Planned	2019	Gas Natural Fenosa has announced that it will be developing bunkering infrastructure to support the 10-year LNG supply deal it concluded in January 2018 with shipping company Baleària.
Jacksonville-Talleyrand Marine Terminal	Tank-to-Ship	500,000 gallon storage tank and loading jetty	Eagle LNG	Under construction	Q32019	Eagle LNG (SEA¥LNG members LNG bunkering infrastructure case study available at https:// sea-lng.org/wp-content/uploads/2018/01/ FINAL_SEALNG-case-study_Eagle-LNG_Shore- to-ship-LNG-bunkering-in-Jacksonville.pdf. Case Study Summary: Eagle LNG and Crowley Maritime have developed an innovative supply chain for LNG bunkering in the space of 2 years. Their success has been based on choosing the right experienced partners, and the right business models, enabling risks to be shared, which is vital in the early stages of market development when infrastructure is scarce.
Tacoma	Tank-to-Ship	30,000 cum storage	Puget Sound Energy	Planned	2019	LNG will be supplied from Puget Sound Ener gy's planned liquefaction plant.
Vancouver	Shore-to-Ship and Ship-to-Ship		Seaspan	Planned	TBC	Seaspan is planning an LNG bunkering jetty / bunkering vessel. LNG for Seaspan bunkering project will be supplied from the FortisBC Tilbury liquefaction plan.
Jacksonville - Dames Point Terminal	Truck-to-Ship and Barge-to Ship (planned for 1H 2018)	Liquefaction plant capac ity 120,000 gallons per day; two storage tank capacity 2	JAX LNG are the LNG supplier; Clean Marine Energy will be the commercialmanager of the Clean Jacksonville bunker barge	Operational	2016	Truck-to-ship bunkering to tote Marine containerships using ISO containers via a custom-built transfer skid.

	-	million gallons				LNG currently sourced by JAX LNG, from AGL Resources’ LNG produc tion facility in Macon, Georgia. In 2018, Barge to-Ship LNG bunkering will commence via the Clean Jacksonville bunker barge, operated by Clean Marine Energy. In the space of just over 3 years, Jacksonville has gone from a port with limited experience of LNG, no existing infrastructure, and a relatively small market in marine fuel bunkering, to become the leading LNG bunkering operation in the US and one of the first movers globally. The Jacksonville case study illustrates the importance of a forward-looking anchor customer and strong leadership. This is what provided the catalyst for innovative supply chain investments, with both customer and supply chains collaborating closely with the port, regulatory authorities, local emergency services, and communities.
Incheon	Truck-to-Ship		KOGAS	Operational	2013	LNG sourced from KOGAS's Pyeong-Taek LNG re-gas terminal.

Source: SEA¥LNG

LNG Bunkering Locations – Current and Planned – Part 3

Port	Type	Capacity	Operator	Status	Start Date	Comments
Ulsan				Proposed	2019	Ulsan Port Authority signed a 3-year co-operation agreement in August 2016 amongst 14 public and private organisations to develop LNG bunkering. Companies include KOGAS, Korea Gas Technology Corporation, Hyudai Heavy Industries, SK Shipping, Korea Research Institute of Ships and Ocean Engineering, Ulsan University, Korea Elenji Solutions, NK, South Korea LNG Bunkering Industry Association, Energy Innovation Partners, Daechang Solutions, and Unisys International.
Kochi	Tank-to-Ship	2x155,000 cum storage tanks	Petronet LNG	Operational	2015	Petronet LNG (SEA¥LNG member) LNG bunkering infrastructure case study available to view at https://sea-lng.org/wp-content/uploads/2018/01/FINALrevised_SEALNG-case-study_Petronet-LNGs-Kochi-Terminal.pdf. Case Study Summary: The Kochi case study illustrates how LNG bunkering may evolve outside traditional deep-sea bunkering locations on the back of strategically located bulk LNG infrastructure. It shows how opportunities may be captured by new entrants who are prepared to move quickly and work with experienced bunkering partners, as well as emphasising the importance of effective education and collaboration.
Yokohama	Truck-to-Ship, Plans for Ship-to-Ship by 2020	TBC	Gas4Sea, Tokyo Gas	Operational	2015	Truck-to ship bunkering started in 2015. Strategic plan to turn Port of Yokohama into an LNG bunkering hub. Ship-to-ship bunkering planned for 2020 based on the Sodegaura LNG regas terminal in Tokyo Bay.
Shanghai (Zhejiang Zhoushan)	Tank-to-Ship, Ship-to-Ship	Ship-to-Ship	ENN Group	Under construction	2018	ENN is constructing an LNG receiving and bunkering terminal of 3Mtpa capacity. ENN has ordered an LNG bunker vessel due to be delivered in 2018
Hamburg	Truck-to-Ship, Tank-to-Ship	5,500 cum storage	Nauticor	Under construction	2017	
Gothenburg	Ship-to-Ship		Skangas	Operational	September 2016	LNG bunkering available from LNG carrier Coral Energy.
Hammerfes (Polarbase)t	Tank-to-Ship	90 tonnes/h	Barents Naturgass AS	Operational	April2017	Norway’s biggest LNG bunkering facility. LNG sourced from Statoil’s liquefaction LNG plant at Melkøya.
Stockholm	Tank-to-Ship, Ship-to-Ship	20,000 cum storage tank	Nauticor, AGA	Operational	2011	LNG terminal in Nynäshamn in operation since2011 LNG bunkering vessel Seagas in operation since 2013.

Source: SEA¥LNG

LNG Bunkering Locations – Current and Planned – Part 4

Port	Type	Capacity	Operator	Status	Start Date	Comments
Klaipeda	Truck-to-Ship, Ship-to-Ship(from 2H2017)	5,000 cum storage	Port of Klaipeda, Blue LNG, (Nauticor/ Klaipeda Nafta JV)	Under construction	2H 2017	LNG supplied from Klaipedos Nafta's LNG FSRU terminal. LNG bunkering vessel Seagas.
Barcelona	Truck-to-Ship; Ship-to-Ship in 2019	TBC	Gas Natural Fenosa	Operational	January 2017	LNG supplied from ENAGAS's Barcelona re-gas terminal. Gas Natural Fenosa has announced that it will be an LNG bunkering vessel to support the 10-year liquefied natural gas (LNG) supply deal it agreed in January 2018 with shipping company Baleària.
Zeebrugge	Truck-to-Ship, Tank-to-Ship, Ship-to-Ship	TBD	Gas4Sea/ Fluxys	Operational	2015	The Port of Zeebrugge has been pioneering the development of LNG bunkering in Northwest Europe. LNG is supplied from Fluxys LNG re-gas terminal at Zeebrugge. The ENGIE Zeebrugge, the world's first purpose-built LNG bunker vessel, was delivered to Gas4Sea (Engie Mitsubishi and NYK Line) in February 2017. Gas4Sea (SEA¥ LNG members) LNG bunkering infrastructure case study available at https://sea-lng.org/wp-content/uploads/2018/01/FINAL_SEALNG-case-study_Gas4Sea-ENGIE-Zeebrugge.pdf. Case Study Summary: The ENGIE Zeebrugge LNG bunker vessel case study illustrates the first mover challenges Gas4Sea needed to address to develop LNG bunkering services in northwest Europe. These included the design of the bunkering vessel, absence of relevant regulation, the need to create customer confidence, and the lack of understanding in the shipping industry of LNG as a marine fuel. Overcoming these challenges required close collaboration with a variety of stakeholders.
LA/Long Beach				No plans yet		No announcements at present.
Algeciras	Land based initially	TBC	Gas Natural Fenosa	Proposed	2019	Considering LNG as a bunker fuel. Participant in Core LNGas Hive initiative. Gas Natural Fenosa has announced that it will be developing infrastructure to support the 10-year liquefied natural gas (LNG) supply deal it agreed in January 2018 with shipping company Baleària.
Panama	Port of Colon	TBC	Engie/AES	Planned	2018	Engie and AES to develop LNG bunkering service based on the Costa Norte LNG re-gas terminal due online in 2018.

Source: SEA¥LNG

LNG Bunkering Vessels – Current and Planned – Part 1

Location	Vessel	Start Date1	Capacity	Operator	Comments
Singapore	FueLNG LNG bunker vessel - to be named	Q3 2020	7.500 cum	FueLNG (Keppel O&M - Shell Eastern Petroleum JV)	Being built by Keppel Offshore & Marine (Keppel O&M) SGD50m contract Maritime and Port Authority of Singapore (MPA) co-funding - SGD3m (US$2.3m)
Bilbao, Spain	Oizmendi	February 2018	600	ITSAS Gas (part owned by Vasco de la Energía)	Oizmendi is a 3,200 dwt former pollution control vessel converted with two 300 cum, deck-mounted, Type C LNG tanks Pilot Ship-to-Ship transfer of approximately 90 cum of LNG, from Oizmendi to the cement ship M.V. Ireland, moored in the port of Bilbao, complet-ed at beginning of February 2018
US Southern East Coast	Shell US East Coast LNG Bunker Barge (to be named)	2020 - TBC	4,000	Shell	Shell Trading (US) has finalised a long-term charter agreement with Q-LNG Transport, LLC for a US-flag 4,000 cum LNG bunker barge.
Sardinia - TBC	Stolt-Nielsen LNG Bunker- ing Vessel (Mediterra-nean, to be named)	2Q 2019	7,500	TBC	Stolt-Nielsen Gas BV has signed a contract with Keppel Singmarine for the construction of two LNG carriers capable of ship-to- ship bunker-ing. Slated for operations in the Mediterranean and northwest Europe.
NW Europe	Stolt-Nielsen LNG Bunker- ing Vessel (NW Europe, to be named)	3Q 2019	7,500	TBC	Stolt-Nielsen Gas BV has signed a contract with Keppel Singmarine for the construction of two LNG carriers capable of ship-to-ship bunker-ing. Slated for operations in the Mediterranean and northwest Europe.
South Korea - TBD	Korea Line LNG Bunker-ing Vessel (to	2019	7,500	Korea Line	Korea Line has ordered two small-scale 7,500m³ LNG carriers from Samsung Heavy Industries for delivery in May and Decem-

	be named)				ber 2019, to be deployed on domestic coastal trades. The first vessel will deliver small-scale shipments of LNG Jeju island for a 20-year contract and the second will supply LNG as marine fuel.
Rotterdam, Netherlands	Shell Rotterdam LNG Bunker Barge (to be named)	2H 2018	3,000	Shell	Shell entered into an agreement with Victrol NV and CFT for a vessel that will operate on Europe's inland waterways from its base in Rotterdam, the Netherlands.
Rotterdam, Netherlands	Total LNG Bunkering Vessel	2019 TBC	18,600	Total Marine Fuels	Total is looking to charter an 18,600 cum capacity LNG bunkering vessel from MOL to supply CMA-CGM's recent order of nine 22,000 TEU box ships.
TBC	Coral Methane	TBD	7,551	Shell	Plans to convert the 2009 LNG/LPG/LEG multi-gas carrier, developed for Gasnor (Shell subsidiary), enabling it to function as an LNG bunker vessel, by adding a specialised LNG bunker arm.

Source: SEA¥LNG

LNG Bunkering Vessels – Current and Planned – Part 2

Location	Vessel	Start Date1	Capacity	Operator	Comments
Barcelona, Spain	Gas Natural Fenosa LNG Bunker Vessel	2020 TBC	TBD	Gas Natural Fenosa	Dedicated LNG bunker vessel to service the10-year LNG supply deal signed in January2018 with Baleària, for their operations out of Barcelona.
Amsterdam, Netherlands	FlexFueler001	2018	760 initially, increasing to1,480	Titan LNG	LNG Bunkering Pontoon - will supply fuel to inland barges and small seagoing vessels
Zhoushan, China	ENN LNG Bunker Vessel - To be named	2018 (TBC)	8,000	ENN Group	
Klaipeda, Lithuania	Blue LNG	1H 2018	7,500	Blue LNG (Nauticor/ Klaipeda Nafta JV)	
Port of Jacksonville, Florida	Clean Jacksonville	1H 2018	2,200	Jax LNG / Clean Marine Energy	
Port of Zeebrugge	Engie Zeebrugge	April 2017	5,000	Gas4Sea	
Port of Rotterdam	Cardissa	August 2017	6,500	Shell	
Kiel Canal to Southern Norway	Coralius	September 2017	5,800	Skangas	
Stockholm	SEAGAS	2013	187	AGA / Nauticor	

Source: SEA¥LNG