Chapter 1

LNG Market in Asia

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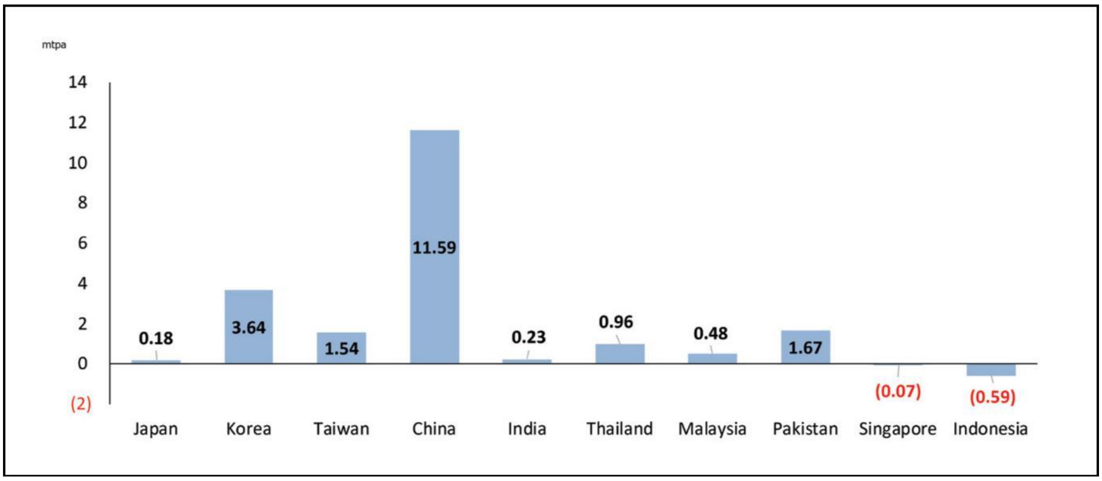
Chapter 1
LNG Markets in Asia

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

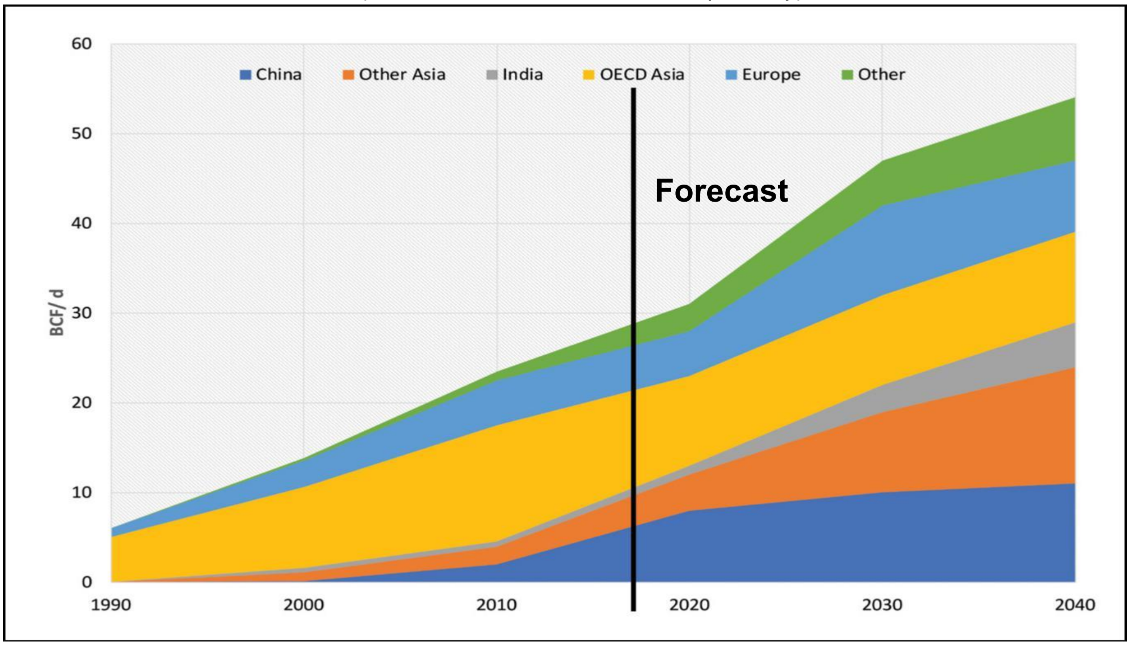
1-1-1. Overview

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

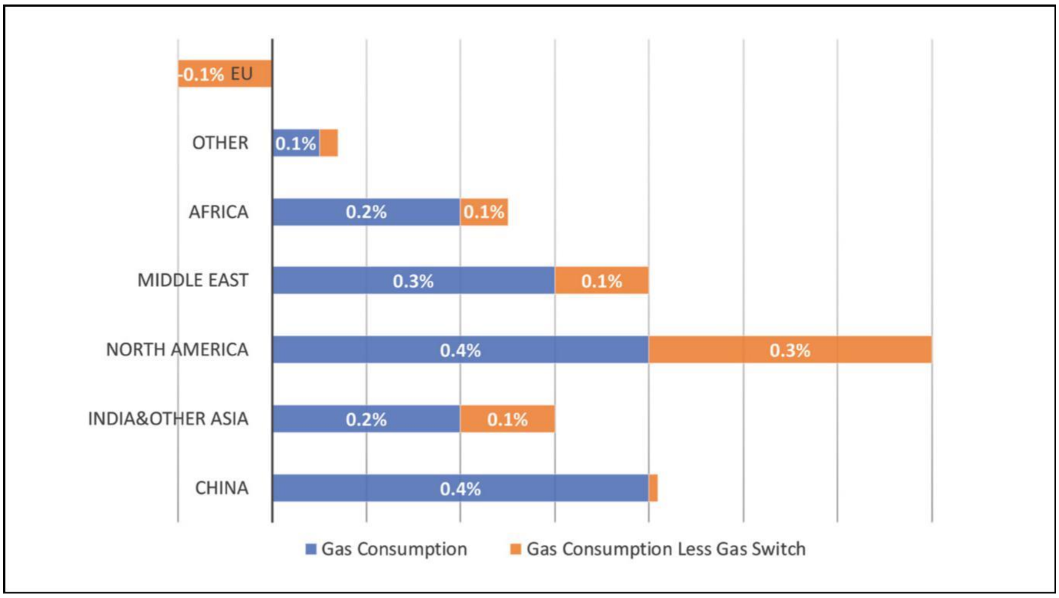
During the winter of 2017–2018, much of northern China experienced significant natural gas shortages. Demand surged, owing to the government's ambitious coal-to-gas switching programmes, and domestic production and pipeline imports could not meet it. Several factors contributed to these severe shortages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

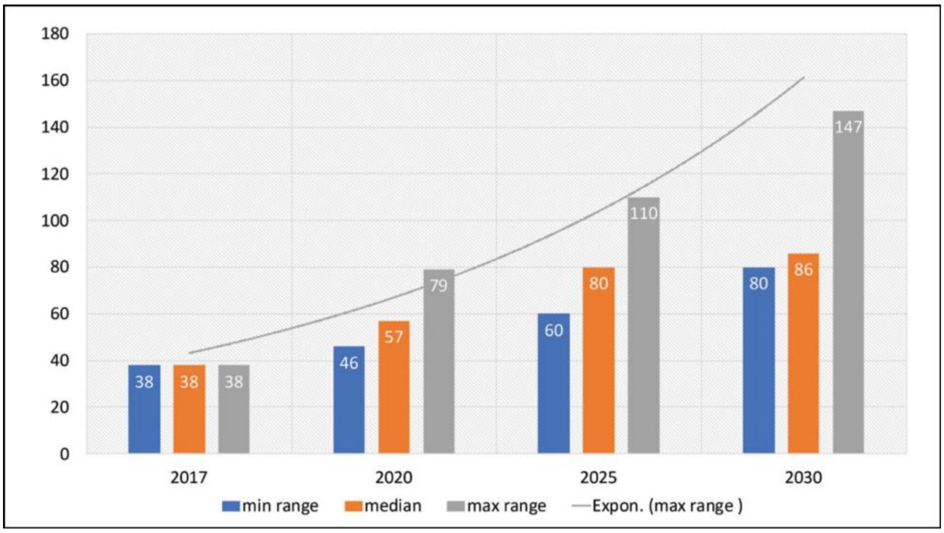
China relies heavily on pipelines from Central Asia for natural gas. In the second half of 2017, pipeline deliveries from Turkmenistan fell substantially. Chinese buyers attempted to offset the reduced volumes with more supply from Kazakhstan and, to a much lesser extent, Uzbekistan. CNPC rushed to bring 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

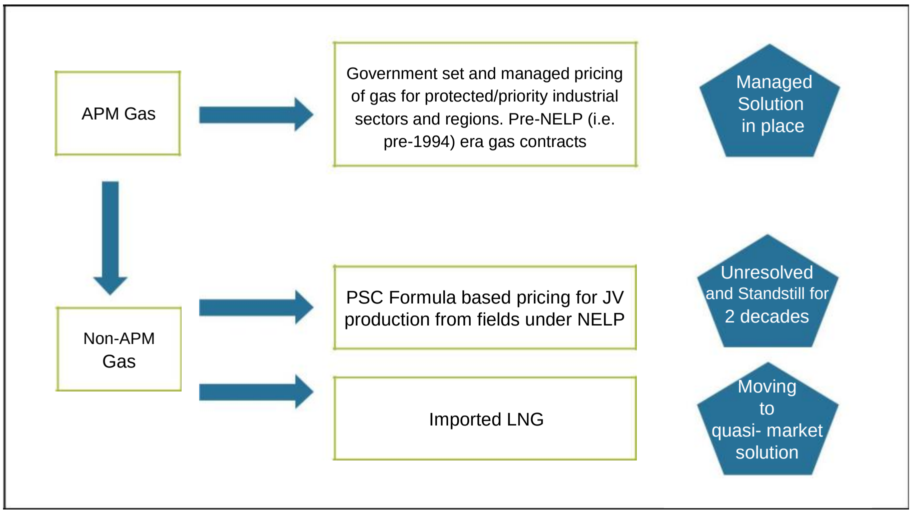
There are many reasons why the term 'wild card' is apt for the Indian gas market. In contrast to most Asian gas markets, power generation is not likely to be a driver of gas growth in India. Other forces, such as rapid urbanisation, industrialisation, and transportation will be the drivers in the short-to-medium 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.

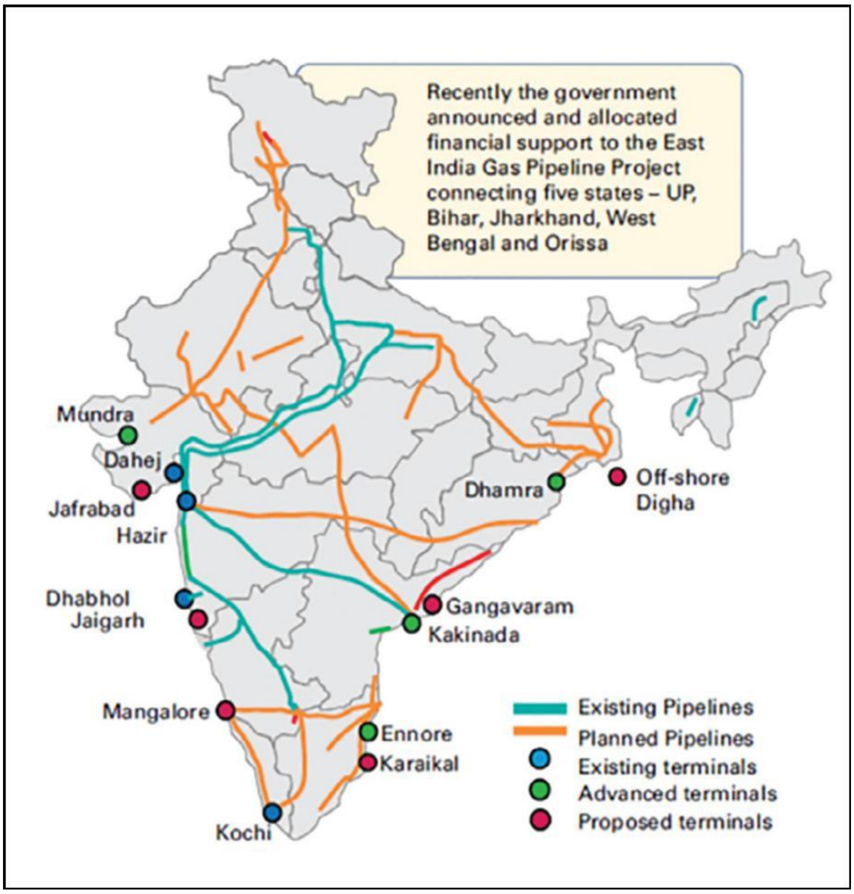
1-2-4. Urbanisation and Transport Driven Gas Growth

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.

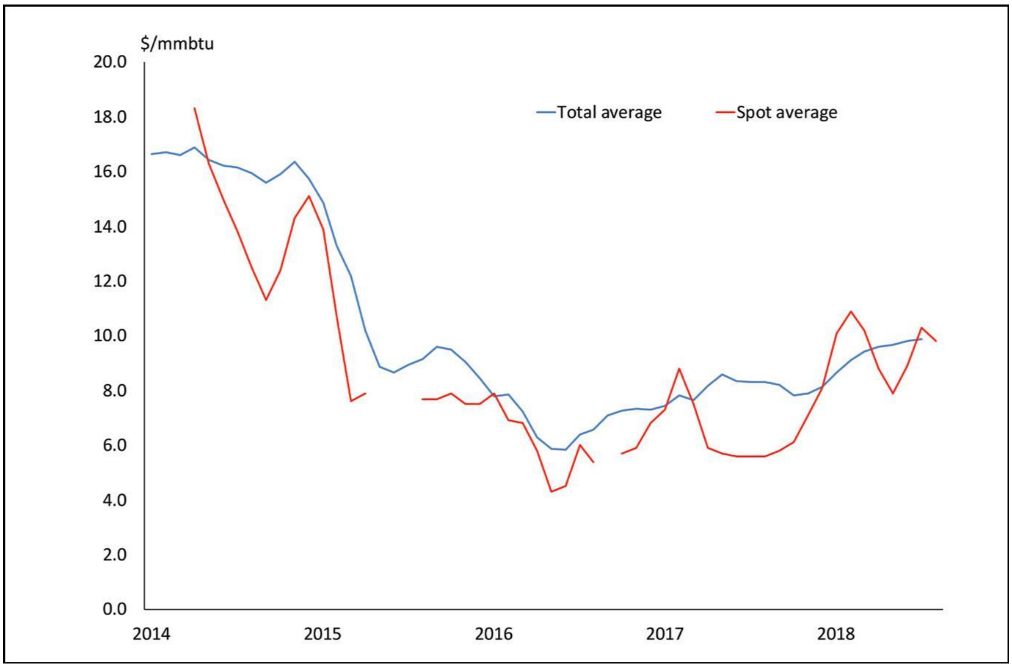
Some emerging Asian countries have already set energy or power generation mix targets, but in many cases, there is insufficient capability or clear government actions to realise the target. Such a lack of policy commitments and administrative capability makes the future energy or power mix more uncertain. 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

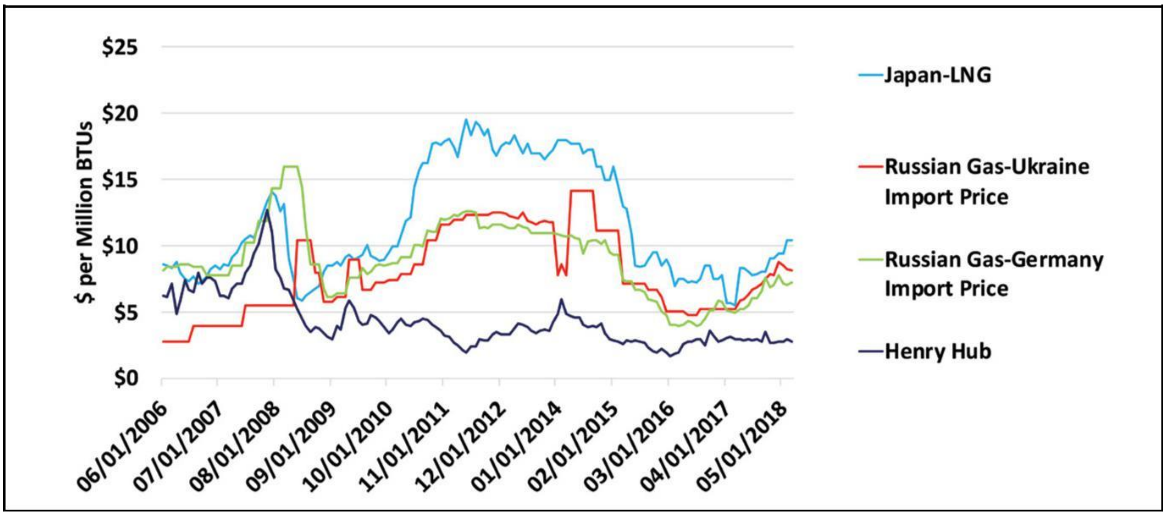
(US dollars per million BTU)



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.