Natural Gas Utilization in APEC: Is the Golden Age of Gas Still Probable?

by

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Abstract

In the early 2010s the International Energy Agency (IEA) forecast that the world could soon enter a ‘Golden Age of Natural Gas’. Both supply and demand of natural gas were growing steadily, energy prices were rebalancing after the 2009 crash and gas was increasingly seen as a means to accelerate the transition away from more carbon-intensive fossil fuels. Although three specific factors were identified by the IEA – increased policy-driven gas penetration in China, a decline in nuclear ambitions following Fukushima and higher gas demand in transportation – the broader implications could be summarized as lower and more competitive natural gas prices relative to competing fuels. This study explored the various reasons for which increased natural gas utilisation failed to materialize, from macroeconomic conditions to government policy and inter-fuel competition affected by global commodity markets. This paper examines these different challenges in the context of five case-study economies: China, Indonesia, Japan, the United Kingdom and Viet Nam.

1 Introduction

This report examines why the golden age of gas failed to materialise in some (if not most) APEC economies¹, what prevented it, and what will be needed to promote the use of gas in the Asia-Pacific region. To begin, however, it is first necessary to examine what the golden age of natural gas is and what was expected to happen once it materialised.

What is the Golden Age of Gas?

A simple definition of the golden age of natural gas is that both demand and supply significantly expand without increasing price volatility. This phrase spread through the energy industry in 2011 with the publication of a report by the IEA. In this IEA report, Are We Entering a Golden Age of Gas?, supply and demand predictions were made in scenarios that showed a rapid expansion of natural gas usage (Figure 1) with global natural gas demand projected to increase by 488 Bcm (15.8% increase) from 2009 to 2015, and to 812 Bcm (26.3% increase) by 2020.

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¹ The word 'economies' is used to describe APEC members because the APEC cooperative process is predominantly concerned with trade and economic issues, with members engaging with one another as economic entities.
Figure 1: Demand forecast in the IEA’s “Golden Age of Gas” scenario, 2009-30

Source: IEA (2011)

Actual natural gas demand

Although there were high expectations for natural gas demand, actual demand growth differed greatly by region. Figure 2 compares demand estimated as of 2015 in the above “Golden Age of Gas” scenario with actual gas demand in 2015. In North America, the home of the shale oil revolution, there was an increase in demand that exceeded the initial forecast. Demand also increased more than forecast in the Pacific region of the Organisation for Economic Co-operation and Development (OECD), including Japan, where demand for LNG rose due to the Great East Japan Earthquake. However, in other areas, actual demand growth was smaller than under the “Golden Age of Gas” scenario. There was a large difference between forecast and actual results in Europe and other Asia, and the conditions in these economies highlight the fact that the golden age did not spread globally as expected.

Figure 2: Forecast and actual demand under the “Golden Age of Gas” scenario, 2015

Source: IEA (2011) and Cedigaz (2016).
The basis for the arrival of the golden age

**Shale revolution**

As of 2011, there were several reasons for robust expectations that a “golden age” would materialise in the future, the foremost of which was the shale revolution in the US. Figure 3 shows the technically-recoverable resources for shale gas around the world as assessed by the US Energy Information Administration. Particularly noteworthy are the large resources that exist outside North America. In addition, there are many shale resources, for example, in Middle Eastern oil-producing economies. With the shale revolution, natural gas resources shifted from a state of increasing scarcity to increasing abundance. The possibility of peak production due to resource availability has been effectively marginalized by the shale revolution.

Figure 3: Global technically-recoverable resources for shale gas, in Tcf, 2015

![Figure 3: Global technically-recoverable resources for shale gas, in Tcf, 2015](image)

Source: EIA (2015)

**Rapid increases in LNG liquefaction capacity**

Another factor is the rapid increase in LNG liquefaction capacity, which expanded from 186.3 million tons in 2005 to 315.8 million tons by 2015, a 1.7-fold increase driven by greater capacity in Australia, Qatar and other economies. Liquefaction capacity is forecast to increase to 437.1 million tons by 2020 and was expected to greatly contribute to the materialisation of the golden age.

Figure 4: Global LNG production capacity, 2005-20

![Figure 4: Global LNG production capacity, 2005-20](image)

*Note: 2020 figures are estimated by IEEJ*

*Source: GIIGNL (2016)
Change in attitude toward nuclear power generation

Another factor that was expected to increase gas demand was the changing attitude towards nuclear power generation after the March 2011 accident at the Fukushima Daiichi Nuclear Power Plant, which triggered a significant worldwide reaction to the safety and use of nuclear power. In July 2011, four months after the Great East Japan Earthquake, Germany enacted a law shutting down all domestic nuclear power plants by the end of 2022. In Italy, although all nuclear power plants had been previously shut down in 1990, following the Chernobyl accident, a referendum on resuming operation of these plants in June 2011 resulted in 90% of the vote cast against re-starting operations. It is widely accepted that these decisions were possible in European economies because of the existing highly integrated gas network.

Recently, Chinese Taipei has also formally decided to shut down its nuclear power plants. Ms. Tsai Ing-Wen, who became president in May 2016, has decided to eliminate domestic nuclear power generation by 2025. The accident in Fukushima also prompted Kuwait to withdraw plans for nuclear power plants. With many economies around the world re-evaluating the use of nuclear power, gas demand was expected to increase in the future by reinforcing gas thermal power generation as an alternative power source.

Response to environmental problems

Finally, growing efforts to tackle climate change and to control environmental pollution was expected to propel demand for natural gas as the cleanest source of fossil fuel energy. The Paris Agreement adopted in December 2015 was designed to reduce emissions from all signatory economies to the United Nations Framework Convention on Climate Change (UNFCCC). The emission reduction target agreed upon in the Paris Agreement (COP 21), the goal of keeping the global average temperature increase within two degrees from the time of the industrial revolution, is considered to be very challenging. However, the agreement is dynamic and it is designed to further strengthen the movement toward emission reductions worldwide by including all developed and developing economies and introducing a “ratchet up” mechanism that gradually increases the targets of each economy.

In addition to reducing greenhouse gas emissions, economies are trying to expand the use of natural gas as an alternative to coal to combat air pollution and soil contamination problems. For example, to alleviate China’s environmental issues, the target for the proportion of natural gas use in the primary energy supply was raised from 5.1% as of 2014 to 10% by 2020. For the same reason, India has also set a target of raising the share of natural gas from 5.2% as of 2014 to 15% by 2030. Addressing these environmental problems was further seen as a factor that would promote future increases in natural gas demand.

2 Why did the “Golden Age” fail to materialise?

There were great expectations for a golden age of natural gas, but with the exception of the United States and a few other economies, why did it fail to materialise? There are six main contributory factors.

Macroeconomic slump

One reason was a global macroeconomic slump. Economic growth rates were forecast to be higher than actual growth. For example, in 2011, the medium term global annual growth rate was predicted to be around 4%, with forecasts for developing economies to maintain growth at a range closer to 6%. However, the actual economic growth rates did not meet these initial expectations. Europe saw the largest discrepancy in the economic growth expectations as the slump in the economy exacerbated other economic problems, such as Greece’s financial crisis, and had the effect of reducing the demand for natural gas. Even China’s growth has been slowing slightly since 2015, and this economic slowdown is thought to have affected domestic energy demand and demand in other Asian economies with close economic ties to China.
Relative competitiveness of coal

Even in economies where energy demand continues to grow, natural gas demand has been sluggish due to competition with other fuels, and in particular with coal in the power generation sector. Coal emits more harmful substances, such as carbon dioxide, than natural gas, but it is generally less expensive.

In the United States, where the shale revolution has advanced, coal and natural gas prices are highly competitive, which led to an increase in coal exports from the United States until 2012 prior to the relaxing of international coal demand and supply.

In emerging Asian economies where energy demand is currently growing – for example, China, India, Indonesia and Viet Nam – coal continues to be the preferred fuel because of abundant resources and the cheaper cost. Natural gas not only has a high price, but also requires the development of infrastructure. In economies where energy demand is rapidly growing, gas development is a more capital-intensive decision than coal when it comes to choosing and expanding use of a particular energy source.

Similar circumstances exist in East Asian economies. In Japan, the electricity market was fully liberalised (including the retail sector) in April 2016. Because of the liberalisation, power companies are planning numerous new coal-fired plants to secure more competitive power sources. Even in Korea, there is a strong interest in controlling power costs in order to ensure industrial competitiveness. Furthermore, according to the 7th Basic Plan for Electricity Supply and Demand announced by the Ministry of Trade, Industry, and Energy of Korea in July 2015, there are plans to expand coal-fired power generation capacity from 26 GW as of 2014 to 44 GW by 2029. However, changes to long-term planning for the development of new power generation expect to be influenced by the newly elected President and promises to shift away from coal (Reuters, 2017).

In the European market, where there is a focus on combating climate change, emissions trading was introduced in 2005 to curb the use of coal and other fossil fuels, even though in recent years the traded carbon price has been particularly low. It was originally assumed that the carbon price would rise to a certain level, thereby restricting the use of carbon-intensive fuels such as coal. In actuality, energy demand decreased during the economic downturn and a reduced price of carbon had little effect on curbing coal use.

Competition with policy-supported renewable energy

The adoption of renewable energy is putting a check on the increase in demand for natural gas and coal. In many economies, renewable energy is a top priority in the energy mix, and its adoption is steadily increasing under policies such as feed-in tariffs. Even in forecasts by international institutions such as the IEA and APERC, renewable energy is expected to have the highest rate of growth in the future energy mix.

With the government supporting renewable energy, natural gas is at a relative disadvantage (despite sometimes having superior cost competitiveness) and is unable to increase its demand share. With respect to solar photovoltaic (PV) in particular, the production of panels has increased because of policy support, and generation costs continue to decline. In the Middle East, which has an abundance of solar resources, the UAE can generate solar PV power at the extremely low price of three cents/kWh. Although these costs are extremely low, solar may not be compatible for all economies. Costs are expected to continue to fall in the future, and policy support will probably continue for wind and geothermal power. The competitive environment for natural gas will become tougher against not only coal, but also renewable energy.

LNG price formula

The current price formula for LNG trading in Asia has also had the effect of suppressing the growth of natural gas demand. Since LNG requires a huge initial investment, most LNG is traded on long-term contracts where the price of the contract is determined in part by the price of crude oil. Originally, this was because LNG was used as an alternative fuel to oil. In 2010, LNG prices rose alongside the price of oil when it surpassed $100/barrel, hampering the development of new demand, especially in emerging economies.
The fall of crude oil prices in the latter half of 2014 has contributed to a decline in contracted LNG prices, resulting in the development of new demand in the Middle East and South Asia. Although the capacity of these emerging LNG importers continues to expand, it is currently only approximately 10 million tons, a level that is relatively small compared with world demand for LNG (250 million tons) and insufficient to compensate for the overall sluggishness of global demand for natural gas.

The adverse effects on natural gas affordability from linking the price of LNG to crude oil over this period led to a movement in Asia to create an alternative price index to reflect the true supply and demand fundamentals of LNG. In Singapore, the Singapore Exchange (SGX) publishes the SGX LNG Index, a free-on-board Singapore LNG price index, and in Tokyo, the Tokyo Commodity Exchange has also announced an LNG price index for LNG arriving in Japan. However, both have low transaction liquidity and have not been used as a price index by many market participants.

**Lack of infrastructure**

Natural gas infrastructure, both upstream and downstream, plays a significant role in determining potential for gas demand. Most gas demand forecasts based on econometric models face difficulties in providing accurate projections due to uncertainty in future physical infrastructure completion. One of the major reasons for the sluggishness of natural gas demand is that infrastructure development did not progress at sufficient levels and on timelines as originally expected. In India, natural gas is mainly for industrial use, which includes power generation and as a fertilizer feedstock, but its demand is limited to coastal areas where supply infrastructure is well developed. Demand in inland areas could potentially increase, but without a developed pipeline network, the expansion of gas usage has failed to materialise (Ernst & Young, 2016). In the ASEAN region, where gas demand is expected to grow, despite a plan to improve the regional pipeline network that has been under discussion since 2002, no major progress in construction has been made as economies in the region have started to shift from building trans-border pipelines to LNG imports. The development of infrastructure in some economies could be treated as a public good, requiring a means of support from government that has not always been sufficiently provided.

**Production constraints**

In some economies, declining domestic production limits gas demand growth. For example, the production of offshore gas in Indonesia has not reached the scale originally planned, leading to sluggish domestic demand. Figure 5 shows the growth in domestic demand is directly reflected in domestic production growth as seen in two economies, Viet Nam and Indonesia.

Figure 5: Natural gas production and demand in Viet Nam and Indonesia, 2008-14

![Graph showing natural gas production and demand in Viet Nam and Indonesia, 2008-14](Source: IEA (2016a))
Through different combinations of the six factors mentioned above, global natural gas demand has not grown as originally expected. The following chapters will review the status of natural gas usage in six major economies and the issues surrounding the expansion of future use.

3 Methodology

Analysis of case studies based on past and current policies in promoting gas, as well as barriers based on observations, data analysis, research paper and official announcements.

4 Case Study

This paper examines these different challenges in the context of five case-study economies: China, Indonesia, Japan, the United Kingdom and Viet Nam. This section will discuss both the challenges and the efforts employed to promote gas use in each respective economy.

China

Natural gas is a small but growing component of China’s primary energy supply. In the first half of 2015, the consumption of natural gas was 91 Bcm, a rise of 2.1% from the same period in 2014, and was 5.5% of the energy mix. Production over the same period increased 3.8% year-on-year to 66 Bcm (APERC, 2016). By 2014, the share of gas in primary energy mix reached 5.1%, up from 1.5% in 1990.

Fundamental natural gas policy is laid out in the five-year plans that set forth economic and social development (Table 1). In the most recent 13th Five-Year Plan, formulated in March 2016, the basic energy policy sets forth the energy supply structure, improvement of energy efficiency and the construction of a clean, low-carbon society. It also defines numerical targets to reduce the proportion of coal in the primary energy supply to 60% or less, raise the proportion of natural gas to 10% or more and increase non-fossil energy to 15% or more by 2020.

Table 1: Natural gas in China’s five-year plans

<table>
<thead>
<tr>
<th>Plan</th>
<th>Targets</th>
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<tbody>
<tr>
<td>9th Five-Year Plan</td>
<td>• Promote the use of natural gas</td>
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<tr>
<td>(1996-2000)</td>
<td>• Construct new natural gas pipelines</td>
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<td></td>
<td>• Increase share of natural gas in the energy mix</td>
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<td></td>
<td>• Shift fuel from coal to natural gas</td>
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<tr>
<td>10th Five-Year Plan</td>
<td>• Accelerate construction of pipeline network</td>
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<tr>
<td>(2001-2005)</td>
<td>• Increase share of natural gas in primary energy consumption from 3% to 6%</td>
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<tr>
<td></td>
<td>• Expand exploration and development abroad</td>
</tr>
<tr>
<td>11th Five-Year Plan</td>
<td>• Expand exploration and investigation of unconventional resources</td>
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<tr>
<td>(2006-2010)</td>
<td>• Increase natural gas production</td>
</tr>
<tr>
<td></td>
<td>• Construct LNG liquefaction project</td>
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<tr>
<td>12th Five-Year Plan</td>
<td>• Strengthen exploration and development of gas resources, and increase natural gas production</td>
</tr>
<tr>
<td>(2011-2015)</td>
<td>• Promote development and use of unconventional resources (coal seam gas, shale gas, etc.)</td>
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<tr>
<td></td>
<td>• Infrastructure development such as gas pipelines, natural gas storage facilities, LNG terminals</td>
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<tr>
<td></td>
<td>• Best mix of gas in energy supply structure</td>
</tr>
<tr>
<td>13th Five-Year Plan</td>
<td>• Reduce government interference and deregulate the price of natural gas</td>
</tr>
<tr>
<td>(2016-2020)</td>
<td>• Construction and maintenance of natural gas storage facilities and pipelines</td>
</tr>
<tr>
<td></td>
<td>• Promote reform project to transition from coal to natural gas as a measure to combat air pollution</td>
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<tr>
<td></td>
<td>• Accelerate construction of natural gas peak load regulating power plants</td>
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</table>

Source: IEEJ (2017)

Promoting gas usage in China

In an effort to promote natural gas use, the Chinese government is implementing measures such as:

- Revising the price system by setting an upper limit for the wholesale price (city-gate price) from the trunk line pipeline to the local branch (distribution) pipeline, while local governments set the supply price (retail
price) from distribution pipeline to the end user;

- Opening natural gas market through institutional reform by removing existing barriers and encouraging new businesses to enter the domestic gas market, it is expected that competition will take over and improve the quality of services offered and reduce selling prices;

- Introducing policies that restrain coal consumption by banning coal-fired boilers in cities and by closing inefficient coalmines. In 2016, the Chinese government decided to close 1,000 or more small and aged coalmines and to reduce production capacity by 60 million tons. Furthermore, the State Council announced that it would reduce national coal production capacity by around 500 million tons over a three-to five-year period;

- Developing gas infrastructure such as LNG receiving terminals, natural gas pipelines and natural gas underground storage, in parallel with expanding natural gas production. Besides expanding LNG imports capacity from 3 Mtpa in 2006 to 40 Mtpa in 2015 (Cedigaz, 2016), together with government reforms, new terminals operated by non-state-owned oil companies have been allowed to enter the market. In addition to LNG terminals, the 13th Five Year Plan focused on developing the natural gas transport routes of the West-East Gas Pipeline, Shaanxi-Beijing Pipeline and Sichuan-Shanghai Pipeline;

- The government has also given priority of natural gas usage as a transportation fuel, particularly in automobiles (such as mixed-fuel vehicles with dual diesel and LNG), public buses, taxis, delivery vehicles, long-distance buses, cleaning vehicles, freight cars, and domestic marine vessels.

**Challenges and opportunities in promoting further usage of natural gas**

Although China has set many policies that are intended to further promote gas usage, a few major challenges remain such as:

- **Transparent pricing.** Transparent and timely pricing is still a challenge for gas markets in China. The Chinese government currently controls the price of natural gas and, until recently, the government has adjusted the price to reverse the negative spread between imported gas and crude oil prices. However, as a transparent price index linked with the world market does not exist, it is difficult for businesses to predict future prices. As for gas prices for non-residential use, although changes such as shifting to the netback system and allowing up to a 20% variation from the base price have been made, the price of natural gas is still relatively rigid as compared with the price of petroleum products that fluctuate every 10 working days. The Chinese government has controlled the city-gate price of natural gas to promote fuel transition from oil to gas. However, price controls are disadvantageous in terms of profitability to businesses that enter high-cost shale development and production. Price controls also become a hindrance to LNG or pipeline gas import business operators due to the negative spread, which may hinder stable supply in the domestic market. Therefore, it is necessary to establish a mechanism that allows prices to be set in a timely manner and flexibly based on demand and supply in the market. With this perspective, the Chinese government established a natural gas exchange (Shanghai Petroleum and Natural Gas Exchange; SHPGX)) in the aim of establishing index prices that reflect the supply and demand of natural gas in China, as well as creating a price index in Asia. Unfortunately, the volume of transactions from January to August 2016 was not large enough (1.88 Bcm for pipeline gas and 220,000 tons for LNG) to establish a gas price index. In the future, the number of participants in the market will need to increase in order to establish a true price index;

- **Competing fuels.** Limited expansion of gas use in the power generation sector as the focus for future capacity will be on renewables and nuclear power. In November 2016, the National Development and Reform Commission and the National Energy Administration announced the 13th Five Year Plan for Electric Power Development. The plan will raise the capacity of non-fossil fuel power generation to 770 GW by 2020 in order to achieve the government goal of increasing the proportion of non-fossil energy consumption to about 15%. Even if China promotes policies to curb coal consumption, the expansion of natural gas in the power sector will be limited because of competition from other fuels such as renewable energy and nuclear power;
• **Demand in transportation.** Gas use in the transportation sector has the potential to be the largest opportunity for China to expand gas usage. China is pressing ahead to develop LNG buses and trucks, CNG cars and other vehicles, and the number of LNG filling stations is also increasing accordingly. The government has offered subsidies to consumers when they purchase new energy vehicles by giving preferential tax treatment to these purchases, in addition to introducing a circular on Financial Support Policy on Promotion and Application of New Energy Vehicles from 2016 to 2020. The government further promotes the usage of electric vehicles through the 13th Five Year Plan for Electric Power Development. Above and beyond land transportation, China plans to expand natural gas consumption for river and lake transport vessels by setting both a higher emission standard for domestic shipping vessels by the end of 2015 and by introducing natural gas retrofitting standards for ships by the end of 2020;

• **Geological structure of shale resource.** Expanding shale gas production in China has remained one of the major barriers in promoting gas usage in the economy. Although the Shale Gas Development Plan (2012-2015) announced by the National Energy Administration set a production goal of 6.5 Bcm for shale gas, the actual amount of shale gas produced reached only about 4.5 Bcm in 2015. Sichuan province, considered one of the primary shale gas producing areas, is exceptionally difficult to develop because of its complicated geological structure and a gas reservoir layer that is far deeper than in the United States and other economies.

**Indonesia**

In 2015, Indonesia produced 72.8 Bcm of natural gas, a decrease of 0.9% from the 73.5 Bcm produced in 2014. Some 42% of gas production was exported as LNG and through gas pipelines. Indonesia produced 15.6 Mtpa\(^2\) of LNG in 2015, a decrease of 1.1% from 15.7 Mtpa in 2014. Indonesia also exported more than 9 Bcm of natural gas in 2015 through pipelines to Singapore and Malaysia (Cedigaz, 2016). The industrial sector is by far the biggest user of gas, consuming 13 115 Ktoe (75%) in 2014 and is followed by the others sector with 4 086 Ktoe (23%) and finally the commercial, residential and transport sectors with a combined consumption of 247 Ktoe (1%) (EGEDA, 2016).

**Promoting gas usage in Indonesia**

In 2007, Indonesia enacted the Energy Law (Law No. 30/2007) containing principles on energy resources utilisation and final energy use, security of supply, energy conservation, environmental protection, energy pricing and international cooperation. It defines the outline of the National Energy Policy (Kebijakan Energi Nasional, KEN); the roles and responsibilities of the government and regional governments in planning, policy and regulation; energy development priorities; energy research and development; and the role of businesses. The Energy Law mandates the creation of a National Energy Council (Dewan Energi Nasional, DEN). The KEN defines the respective targets for the components of primary energy supply, by 2025 and 2050, as a share of the supply mix as follows:

- new and renewables at least 23% in 2025 and at least 31% in 2050;
- oil should be less than 25% in 2025 and less than 20% in 2050;
- coal should be a minimum of 30% in 2025 and minimum of 25% in 2050; and
- gas should be a minimum of 22% in 2025 and minimum of 24% in 2050.

However, despite a huge gas resource endowment, Indonesia is not able to meet its domestic gas demand. In 2015, existing production was only able to supply 94% of contracted demand. This was as a result of decreases in existing production coupled with development delays of new fields. For the 2016-2022 period (medium-

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\(^2\) Cedigaz database use Bcm as unit measurement. APERC converts to Mtpa by using the BP conversion factor of 1 Bcm = 0.74 Mtpa of LNG (BP, 2016).
term), growing demand by the industrial and electricity sectors is expected to add additional constraints to the supply side, which has forced the government to consider the possibility of gas and LNG imports in the near future.

**Factors contributing to lower gas demand in Indonesia**

- **Macroeconomic uncertainties post 2014.** From 2011-2014, Indonesian macroeconomic conditions were stable, with economic growth averaging 5.8% per annum. Because of this, the government planned several projects in the power, fertilizer and petrochemical sectors, all of which consume a lot of gas. Macroeconomic instability in 2014 pushed the construction of several gas-fired power plants, delaying construction and leading some industries to run their factories and power plants with more expensive fuel, such as oil, in the short term. This delay caused a few fertilizer and petrochemical plants to run below optimal efficiency, which subsequently lowered productivity. Despite this hiccup, natural gas demand is expected to grow in the future.

- **Contracted exports.** Additionally, since 2012, the volume of gas used in the economy has exceeded the amounted exported. As domestic demand levels have increased rapidly, production has not been able to keep up with both contracted export volumes and higher local demand, leading to insufficient ability to meet local demand.

- **Relative cost disadvantage against coal.** In general, coal prices are lower than natural gas. Given that Indonesia is endowed with huge reserves of coal, coupled with a least cost approach electricity generation, coal will always remain high on the power planning agenda.

- **Penetration of subsidised renewable energy.** In order to achieve the target of a 23% share from new and renewable energy in the primary energy mix, Indonesia introduced several policies including a feed-in-tariff (FiT) and incentives to investors and developers to utilise new and renewable energy. Increasing power supply from renewables can be one of the factors that reduces the gas penetration to the market. By using a least cost approach, gas-fired power plants could not compete with big hydropower or geothermal power plants.

- **Lack of infrastructure.** A mismatch between demand centres and producing fields has been identified as one of the major challenges for Indonesia. Geographical conditions – encompassing thousands of islands and large bodies of water – make the development of gas infrastructure challenging. Many gas supply constraints occur because existing infrastructure is not able to handle gas demand increases while the pace of construction for new infrastructure is slow. Part of the solution identified by the government was to turn Arun LNG export facility into a receiving terminal. Since most of the major gas network, particularly on Sumatera Island, is connected to this terminal, gas supply to consumers in this region is expected to improve in near future (ESDM, 2015).

- **Production and resources governance.** Among the barriers, identified by the government, is regulation. Government Regulation number 79 of 2010 (GR 79), related to operations cost recovery and income tax for the upstream sector, is the first regulation dedicated to dealing with the fiscal framework. GR 79 divided upstream players into four main categories, depending on the difficulty of the field developing each field. Since the inception of GR 79 in 2010, several policy issues have discouraged upstream players from investing in exploring new fields (PwC, 2016). In order to remedy this, the government plans to revisit GR 79 and in order to make necessary amendments.

- **Access to resources.** Indonesia had limited exploration success from 2011-2014. Among the factors that have contributed to this situation are a low internal rate of return (IRR) and insufficient open data available for companies to evaluate exploration opportunities. Although some data is available for a fee, the analysis of the data must be performed in the economy. The database also does not specifically identify or assess unconventional gas resources (ESDM, 2016).

- **Lack of regional integration.** Indonesia is connected to Malaysia and Singapore via pipelines, which are currently being used to export gas produced mainly in the Natuna area and from Java Island. Since both economies are rapidly expanding their LNG receiving terminals, Indonesia may be able to import pipeline
gas in the future.

Japan

Natural gas demand has grown consistently since Japan began importing LNG in 1969 as a replacement for coal and petroleum products. Demand for LNG increased sharply as a substitute fuel for oil after the two oil shocks of the 1970s, and as a substitute fuel for nuclear power after the Great East Japan Earthquake in 2011. According to the IEEJ forecast in November 2010, demand for natural gas was expected to gradually increase up to 2020, but the actual increase in demand has been more than 10% to 20% higher than this forecast. This is because there was an increase in the operation of natural gas thermal power plants after the shutdown of nuclear power plants following the Great East Japan Great Earthquake in 2011, causing approximately a 30% increase in gas demand.

The latest Strategic Energy Plan was approved by the Cabinet in April 2014 considered natural gas as “an important energy source whose role is expected to expand.” In addition, the actual policy direction includes the importance of promoting the reduction of import costs through diversification of supply sources, and the diversification of use through cogeneration and hydrogen supply sources. The policy also calls for a shift to natural gas in industrial fields, the advanced use of natural gas in combined cycle thermal power generation, and the preparation for an emergency response system.

Efforts to promote the use of natural gas

The Japanese government has three policy options to promote the use of domestic natural gas: subsidies, taxation and market system reform.

- **Subsidies.** The government allocated 838.4 billion yen (up 5.3% from the previous year) for energy measures special account subsidies for the FY 2016. The government allocated the subsidies across multiple areas, such as in the industrial sector (to convert oil and coal-based boilers and industrial furnaces to natural gas) and to expand cogeneration through the introduction of high-efficiency cogeneration equipment. In the transport sector, assistance for the adoption of next-generation vehicles such as CNG buses and truck, fuel cell vehicles (FCVs) and subsidies for the introduction of consumer fuel cells with the aim of expanding the household use of fuel cells (ENE FARM).

- **Taxation.** Although not as direct as subsidies, the Japanese government is promoting the use of natural gas through a tax system that promotes cleaner fossil fuels. For crude oil, petroleum products, gaseous hydrocarbons and coal imported to Japan, a petroleum and coal tax is imposed on a per unit basis as outlined in the Petroleum and Coal Tax Act. In October 2012, the government introduced a tax to mitigate climate change, which is equivalent to 289 yen per ton of CO₂, and is in addition to the conventional tax rate. With the introduction of the climate change mitigation tax, the tax rate added to coal, becomes relatively large, and the tax rate for coal (steam coal) versus natural gas increased to 1.6 times the cost, up from 1.4 times before its introduction. Although the expansion of the price difference is indirect, it has the effect of promoting the use of natural gas.

- **Institutional reform to expand the scope of retail liberalisation.** In addition to subsidies and taxation, measures are also being developed to promote gas use by introducing market mechanisms in the city gas market that are expected to increase the competitiveness of gas. Japan has been gradually liberalising its market since the 1990s.

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3 This tax was created as the “Oil Tax” in the FY 1978 tax system revision, and was revised to its current name in accordance with the FY 2003 tax reform.
Challenges for developing gas demand

- **Use in the power generation sector.** Gas-fired power has increased to over 40% of the generation mix since the Great East Japan Earthquake of 2011, but there is a strong possibility that gas share will decline in the future rather than expand. The Long-Term Energy Supply and Demand Outlook released in July 2015 shows the breakdown of the power supply mix up to FY 2030, with renewable energy (which in 2015 accounted for 14.3% of generated electricity) increasing to between 22% to 24% by 2030. Nuclear power, which accounted for about 30% of electricity before 2010, was reduced to a range of 20% to 22% in 2030. The outlook also shows the importance of gas-fired power as an intermediate power source with its low greenhouse gas emissions, and maintains its share of the power supply composition at 27%, which is almost the same level as before FY 2010.

- **Expanding city gas sector remains challenging.** Unlike power generation, there is still great potential for the use of natural gas in city gas, although it faces tough competition with other fuels. In the residential sector, it competes with LPG and electricity, while in the industrial sector, gas competes with oil-fired boilers and industrial furnaces (mainly using fuel oil). As such, maintaining competitiveness against other fuels in the city gas sector is the biggest challenge for the future expansion of its use. When compared with the price per heat equivalent of other fuels such as crude oil and LPG, LNG provides a cheaper option for consumers. For this reason, efforts are underway to focus on reducing running costs and to shift from other fuels to city gas.

- **Expanding gas demand in the transportation sector.** Demand will only be able to expand further in the transportation sector, where it currently represents 0.1% of energy use, if there is enough infrastructure on the ground. Japan’s share is particularly low when compared with 3.8% in Korea and 3.3% in the United States. In the transportation sector, it is expected that the use of FCVs as well as conventional NGVs will grow as these vehicle becomes cheaper. The Strategic Roadmap for Hydrogen and Fuel Cells released in June 2014 and revised in March 2016 sets the target for FCVs at 40,000 units (cumulative) by 2020, 200,000 units (cumulative) by 2025, and 800,000 units (cumulative) by 2030. Furthermore, the shipping industry is also pushing for a cleaner fuel by shifting to natural gas (LNG). In response to environmental pollution by vessels that are plying international shipping lanes, the International Maritime Organisation (IMO) has formulated international emission standards, which are based on the International Convention for the Prevention of Pollution from Ships (MARPOL), to curb emissions of NOx, SOx, and CO2.

United Kingdom

Natural gas demand in the UK has undergone a dramatic shift since its introduction in the 1960s. Upstream development in the North Sea has been the primary driver of natural gas use. Throughout the 1970s and 1980s, demand was driven by the industrial, commercial and residential sectors, where natural gas replaced oil products and coal-derived manufactured gas. While these sectors have provided stable demand since then, it was power generation that significantly expanded demand in the 1990s and 2000s. Thus, demand nearly doubled in the 1990s and peaked at 87 Mtoe (91 Bcm) in 2000. However, demand started to decline (a trend that was exacerbated by the 2007/8 financial crisis) and has decreased by 30% since 2000. This swing was caused by lack of competitiveness and government policy to promote renewable energy in the economy’s power mix.

The UK is different from other case study economies in this report in terms of demand decline and energy policy priority. Natural gas has been used for over five decades, and has already replaced other fuels to a significant extent. There was virtually zero gas demand in 1965 when BP first struck natural gas in the North Sea, but by 2014 natural gas accounted for 45% of energy demand in power generation, 31% in industry, and 32% in the residential and commercial sectors. Despite (or perhaps because of) high gas penetration, the government does not have any plans to achieve a higher gas mix in the UK and demand is expected to be flat or falling in the future.
The current energy policy is mainly driven by concern over climate change. Other important policy issues are competition, security of energy supply and energy poverty. The UK has committed to reducing GHG emissions by 40% in 2030 relative to the 1990 level in accordance with the Paris Agreement, which the UK ratified in 2016. The EU Renewable Directive of 2009, that envisions decarbonisation, requires the UK to increase the share of renewables to 15% of the power mix by 2020 (DECC, 2015a).\(^4\)

In 2015, the government announced that it will hold a series of consultations in relation to the closure of coal-fired power plants by 2025 (DECC, 2015b). Although these policies focus on decarbonisation, they have also become one of the factors in the destruction of demand for natural gas.

In the *Annual Energy Statement 2014*, the latest general energy policy paper, the government was largely content with the adequate capacity of natural gas infrastructure in the UK. Although this paper does not specify the role of natural gas in the UK energy mix, it is reasonable to believe that natural gas is expected to provide flexibility in power generation as a backup fuel for renewables amid their rapid increase. In the industrial and household sectors, the demand of natural gas is likely to remain stable, while the transportation sector see some increase, though it will be marginal even in 2035.

The UK possesses well-developed natural gas infrastructure with the about 8 000 km of high pressure pipelines. There are many cross-border connections for natural gas import and export. There are three import pipelines from Norway, one for export to Ireland, and two for both import and export from/to the Netherlands and Belgium. The UK also has four LNG import terminals in operation.

International connection, apart from with Norway, was developed after the privatisation of British Gas. As will be discussed further, the transportation sector of British Gas was unbundled, and it has been under regulation in terms of infrastructure development and rate of return since. Relatively smooth interconnection development under the liberalised market reflects successful incentives to invest in cross border gas infrastructure.

**Liberalisation and development of the wholesale gas market**

In the 1980s and 1990s, the liberalisation of electricity and gas markets in the UK was the main focus of energy policy, not necessarily the promotion of natural gas. Lack of competition prompted the government to accelerate the liberalisation process. As far as the gas market is concerned, the process started in 1987 when the government removed the monopoly status of then-state-owned British Gas and introduced third party access (TPA) to its pipelines. Privatised British Gas was required to transfer 1.2 Bcm/y in 1992-1995 and 0.6 Bcm/y in 1996 to new entrants under the name of a gas release program. The retail market was liberalised in stages beginning in 1982 and fully opened in 1998. British Gas was unbundled in 1997 and the infrastructure became owned and operated by BG plc (now National Grid). Finally, price regulation was lifted in 2002. Thus, the market share of Centrica, which used to be the retail segment of the former British Gas and supplied virtually all domestic markets, declined to 37% in 2015 (OFGEM, 2016).

The liberalisation process, especially TPA and the unbundling of British Gas, resulted in the development of a wholesale gas market in the UK. When the UK gas industry was controlled by British Gas, which was a vertically-integrated monopoly, there was no wholesale price because all the gas flowed through pipelines owned by British Gas. The unbundling of British Gas in 1997 meant that gas now had to be traded between sellers (producers) and buyers (power generators and city gas suppliers). Therefore, a wholesale price had to be formed for their transactions and a wholesale market or hub emerged. Today, the UK wholesale market, known as the National Balancing Point (NBP), is one of the most liquid hubs in the world. Any gas, domestic or imported, entering UK gas infrastructure is priced in accordance with NBP. As NBP became a spot price, the

\(^{4}\) It is uncertain what the legal status of the EU Renewable Directive will be in the UK after Brexit. However, it is expected that decarbonisation will remain central to UK energy policy, and thus the current policy measures will essentially remain the same.
price became volatile and necessitated the creation of a hedging tool for producers and consumers. In response, Intercontinental Exchange (ICE) listed an NBP futures contract in 1997.

UK gas production peaked in 2000, but had fallen to around one-third of this volume by 2013 (a slight increase in production was seen in 2014-15). As mentioned above, TPA was introduced in the 1980s to the gas market in order to encourage competition and break the monopoly of BG in gas supply. From 1980 to 1999, gas consumption closely followed production. However, a new trend emerged after 2000, where gas production decreased much more rapidly than consumption. A few factors may have contributed to this trend:

- Existing and extensive pipeline infrastructure;
- Completion of new facilities, such as LNG import terminals;
- Liberalised market that allows private companies to invest and to compete in the market;
- Gas trade managed to sustain demand at a certain level;
- The UK role as one of the leading gas trading hubs in Europe (assisted by the establishment of futures prices under the NBP); and
- Strong policy in promoting renewables and mitigating CO\textsubscript{2} emission.

Although gas demand began to decrease in 2010, it did not decline as rapidly as production because of gas trade – through pipeline and LNG imports – which sustained a level of domestic demand in spite of declining production. In recent years, rising gas prices have made it harder to compete with renewables and coal. Even with the UK engaged in the process of triggering Article 50, through which the UK will leave the European Union (Brexit), minimal disruption in gas trade, particularly pipeline imports from Belgium, is expected.

**Figure 6: Domestic gas production, demand and imports in the UK, 1980-2016**

<table>
<thead>
<tr>
<th>Year</th>
<th>Consumption</th>
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**Sources:** Cedigaz (2016), BP (2016) and IEA (2008)

**Challenges for demand development**

- **Gas usage in power generation.** Demand destruction was mainly caused by the declining competitiveness of natural gas for power generation. Although demand has shown a slight recovery in recent years, competitiveness in the power generation sector will remain the key for natural gas demand growth. Although it is increasingly difficult to invest in gas-fired power plants due to lower utilisation factors,
natural gas is expected to provide power generation flexibility as a backup fuel of renewables.

- **Gas utilization in other sectors.** According to current energy policy, there are few incentives for gas demand development in the non-power sectors in the UK, at least at the national level. Those few incentives are also, unsurprisingly, in line with decarbonisation. One such incentive is for CHP, whose energy efficiency could be as high as 80%. The Energy Act of 2008 introduced a feed-in-tariff scheme for electricity from CHP plants. Eligible CHP developers can benefit from tax incentives and favourable financing conditions for their CHP plants. Similarly, NGVs face reduced taxation schemes in the UK (NGVA, 2012).

- **Declining domestic gas production.** Gas supply security remains an important policy issue in the UK. The Energy Act of 2016 sets out a legal framework for energy regulation and established the Oil and Gas Authority (OGA) as an independent Government Company to support upstream development in the North Sea. Upstream development and production growth of domestic natural gas resources is aimed at reducing the economy’s dependence on natural gas imports. As far as shale gas is concerned, the British Geological Survey assesses the resource at 1 329 Tcf (Andrews, 2013). In 2015, the government approved hydraulic fracturing for shale gas exploration in a limited area of the UK, although the result of this exploration is unclear (DECC, 2015a). Despite these policies, it is unlikely that natural gas production will recover in the UK.

**Viet Nam**

The natural gas industry in Viet Nam developed from indigenous resources and discoveries. Large scale natural gas extraction has been carried out since 1995 and reached 10 Bcm per year in 2014 (PVGas, 2016a). Growth in the electricity, fertiliser and other industries has driven demand for natural gas. Natural gas accounted for 13% of domestic fossil fuel energy production, 13.7% of total primary energy supply (TPES) and 2.8% of total final energy consumption (TFEC) in 2014 (EGEDA, 2016).

In Viet Nam, natural gas as well as other natural resources are under public ownership and subject to unified management by the government. The government regulates the natural gas sector through a legal structure that includes the Petroleum Law, the Gas Business decree, the Strategy for Development of the Oil and Gas sector and the Gas Master Plan. The last two documents are formulated for 5-10 year periods and issued by the Prime Minister. The Ministry of Industry and Trade (MOIT) is the focal point for the state administration and management of the natural gas industry.

Currently, domestic natural gas production comes from offshore oil and gas fields in the shallow-water areas of four basins - Song Hong, Cuu Long, Nam Con Son and Malay-Tho Chu. Cumulative production was 127.64 Bcm by the end of 2014, of which the Nam Con Son basin produced 48% of the total and was followed by the Cuu Long basin (44%), the Malay-Tho Chu basin (8%) and the Song Hong basin (less than 1%).

The ability to develop domestic natural gas has been the key driver in Viet Nam’s natural gas industry and markets. In other words, geologic conditions in Viet Nam’s petroleum sedimentary basins, upstream financing and the general international economic and commercial situation have supported natural gas exploitation and supply developments in Viet Nam.

In 2015, from total wet gas supply of 10.6 Bcm from all oil and gas fields, Viet Nam produced around 289 000 tons of LPG and 10.45 Bcm of dry gas (PVGas, 2016a). Some 84% of the dry gas supply was used as fuel for power generation, 10% as feedstock for production of urea and ammonia, and 6% as fuel for industrial (such as high quality pottery, ceramic and glass, foods and beverages) and transport consumers. Developments in natural gas utilisation follow not only the strategy for the development of the oil and gas sector, but also have close ties to the government’s master plans for the development of the power, petrochemical and other sectors. Natural gas has also played an important role in implementing Viet Nam’s food and energy security policy. Currently, 70-75% of Viet Nam’s urea consumption is produced in two fertilizer plants using natural gas.
as input feedstock. Combined cycle gas turbine (CCGT) and gas thermal power plants with combined capacity of nearly 8 GW (22% of Viet Nam’s total installed power capacity in 2014) contribute about 31-34% annually of total power generation. LPG production from gas processing plants accounts for about 18-20% of the total domestic market, reducing requirements for Viet Nam oil product imports.

**Efforts to promote the use of natural gas**

The government promotes the development of the natural gas industry with regulations and through international cooperation projects based on market mechanisms. While upstream and downstream gas businesses are open to foreign investment, the government strongly encourages the major state-owned energy companies such as PetroVietnam (PVN), PetroVietnam Gas Joint Stock Corporation (PVGas), and Viet Nam Electricity (EVN) to strengthen their businesses and maintain a central role in Viet Nam’s gas midstream and downstream supply chains. In the upstream business, PVN or its subsidiary PetroVietnam Exploration Production Corporation (PVEP), participate as government representatives in all production sharing contracts (PSCs), joint-ventures (JVs) and business cooperation contracts (BCCs) signed with international investors for oil and gas exploration and production (E&P) activities in Viet Nam. In the midstream, PVN and PVGas take leading investment positions in gas infrastructure projects to support natural gas exploration, production and imports to Viet Nam. Although gas pipeline systems in Viet Nam have diverse forms of ownership, PVGas – a listed public company since 2012 and the only operator of all systems, is responsible for ensuring safe and reliable natural gas supply economy-wide. PVGas, with equity shares of 51%, jointly invested with Bitexco (39%) and TG Asia (10%) to create The LNG Viet Nam in August 2016 (Tokyo Gas, 2016).

PVN and PVGas are the only authorised buyers of natural gas from upstream oil and gas contractors to resell in the Vietnamese market. Upstream sellers and downstream buyers are free to negotiate the price (including a price formula and level) and other terms in the Gas Supply and Purchase Agreement (GSPA) with PVN and PVGas. These upstream GSPAs and related downstream GSPAs – which are conducted between PVN/PVGas and gas-fired power plants and fertilizer manufacturers - must be submitted to authorised organisations and the Prime Minister for approval before going into effect. The government’s approvals for the natural gas price for the Take-or-Pay (TOP) volumes in GSPAs, tariffs in the Transport Agreements (TAs), and regulations on the price for the above-TOP volumes in GSPAs aim to ensure a reasonable profit margin for all investors in the natural gas system/chains, a competitive price for natural gas with alternative fuels in end-user markets, and allow PVN/PVGas to recover reasonable costs in their gas contract and marketing management.

**Factors contributing to lower gas demand**

The shortfall in the expected level of Viet Nam’s natural gas production and consumption over the period 2010-2015 is attributable mainly to macroeconomic uncertainties. However, other factors including gas pricing, lack of infrastructure and uncertainties about resource exploration and production also contributed to the slower than expected development of Viet Nam’s gas market. Although Viet Nam has been actively trying to promote gas utilisation, a few factors contributed to the lower than expected gas take-up such as:

- **Macroeconomic uncertainties.** Macroeconomic assumptions for the period 2010-2015 made in the National Power Master Plan 7 (PMVN, 2011) and GMP 2011, were generally too optimistic. Worldwide economic malaise prolonged the impacts of the global and regional financial crises since 2008, and late in 2014, drops in the world oil prices came suddenly. These events impeded Viet Nam’s ability to attract foreign capital for various planned projects and contributed to the slowdown in Viet Nam’s GDP growth.
- **Pricing mechanism in the power sector.** CCGTs in Viet Nam have different gas price structures, depending on when the plant was built and different costs to produce the gas depending on the specific gas field/source. In 2011, Viet Nam established a competitive electricity market, which allowed power producers to compete based on their generation cost. However, new plants must depend on higher-cost fields which makes industry players quite reluctant to build new CCGTs.
- **Lack of gas infrastructure.** In Viet Nam, CCGTs, fertilizer and petrochemical projects are considered
strategic gas consuming markets and have first priority in natural gas supply allocation. The remaining dry
gas volume for industrial and transport consumers is small and unstable. In addition, current planning
practices for industrial zones in Viet Nam’s provinces do not favour creating appropriate levels of gas
demand to justify low pressure pipeline projects. These issues have hindered the development of the low
pressure gas pipeline system, and the development of the natural gas market for industrial and transport
consumers.

- **Uncertainties about resource exploration and exploitation.** Natural gas production and demand forecasts
  in GMP2011 were made based on government estimates of proved and probable reserves at the end of
  2009 and existing E&P plans in Viet Nam. Reserves data on oil and gas fields, and investment and
  production plans have been revised based on subsequent assessment updates that may induce changes
  in development schedules. In addition, since 2012, China’s actions in the East Sea have complicated Viet
  Nam’s ability to attract investment and sometimes physically interrupted oil and gas E&P activities in Viet
  Nam.

5 Conclusion

Implications for APEC Economies

This chapter will examine the potential policy responses in promoting gas usage in the APEC region. Based on
the discussion so far, a few factors have been identified as barriers that obstruct further gas demand.

Areas where policy response is challenging

**International crude oil and gas prices**

International crude oil and natural gas prices are one of the factors that cannot be addressed through a policy
response. It is a given that to expand gas demand, stable and low gas prices are helpful. In markets where
much of the gas supply is from LNG, such as the Northeast Asian market, and the LNG price is determined by
linking to crude oil prices, the level of both international gas prices and crude oil prices are equally important.

However, the level of crude oil, natural gas and LNG prices traded in international markets is not just limited
to the global supply and demand balance of oil and natural gas. These prices are determined by extremely
diverse factors such as geopolitical risk and movement of investment money in international financial markets,
meaning that policy decisions by governments of various economies do not always have a large effect on the
price itself. Apart from a few exceptions, such as OPEC production adjustments, it can be said that it is almost
impossible for policy measures to control the price level and fluctuation range. Efforts have been made to
stabilise prices through initiatives such as oil stockpiles by member economies of the IEA and the prompt
disclosure of oil demand and supply statistics by the Joint Organisations Data Initiative (JODI), but it is
extremely difficult to fundamentally stabilise these prices in international markets. In considering future gas
usage promotion policies, it would be appropriate to assume that international crude oil and gas prices will
continue to remain unstable.

**Gas trading arrangements between companies**

One of the reasons why regional gas demand has not increased as originally expected is that contracted LNG
has been linked to the price of crude oil, which erodes price competitiveness relative to other fuel sources.
Because LNG requires a huge investment in the development of a supply chain, including its liquefaction
facilities, it is often traded based on long-term contracts of 10 years or more. Among the many long-term
contracts, LNG is an inconvenient energy product from the perspective of its poor financial market liquidity in
some regions, and contract inflexibility such as destination clause restrictions. These types of LNG transactions
are generally agreed upon in the contract between the LNG seller and buyer, and the government does not
intervene in its content.
However, among such LNG trading practices, government competition authorities may have a role to play in the constraints on destinations. The EU has previously deemed it uncompetitive to prevent the free flow of products, and in June 2017, the Japan Fair Trade Commission commented that LNG sellers should not include competition-restraining clauses when negotiating new contracts, which is part of the verdict given on the legality of the destination policy in long-term LNG contracts purchased by Japanese buyers. Liberalisation of destinations is an important condition for building a flexible and fluid international LNG market, and provides a role for the government (via competition authorities) to play in this field.

Areas where policy response is possible

Establishing clear natural gas usage policy

It is essential for the government to establish and define basic policy on how to position natural gas in the future energy demand mix. Natural gas has advantages that other sources of energy do not in terms of being clean, abundant and geographically dispersed. On the other hand, its price is higher than coal, and it has the disadvantage of more expensive transportation infrastructure compared to oil, and it emits more greenhouse gases than renewable energy. It is important to formulate clear usage policies that reflect the characteristics of natural gas, such as how it should be used in the economy’s energy mix.

With the government setting a basic policy, it is desirable that it formulates a more detailed usage plan. Establishing a clear understanding of the role of gas will assist in attracting investment for the future expansion of natural gas use. For example, in the power supply sector, it is possible to develop various power sources such as coal, renewable energy, or nuclear power as well as natural gas, but more detailed policy clarity will encourage investors to consider developing this field.

Construction of infrastructure

Natural gas demand will not grow if supply infrastructure from production to the point of consumption is not developed. Therefore, it is safe to say that the expansion of the natural gas market will only happen with the expansion of natural gas infrastructure. However, natural gas infrastructure, such as LNG terminals, are hugely expensive. For this reason, if there is a clear natural gas use plan by the government and if a certain scale of demand can be confidently expected, investors may be willing to invest to build this infrastructure. However, it may be necessary for the government to provide some of the infrastructure first by contributing funds themselves, or provide incentives such as tax cuts to companies to encourage infrastructure development. For example, many state-run oil companies in Southeast Asia undertake the domestic gas supply business by themselves, including in developing infrastructure.

In addition, the government has a role to play in improving supply infrastructure. For example, the government can help investors by accelerating land acquisition matters for pipelines or LNG terminal construction. An international pipeline (Trans-ASEAN Gas Pipeline) is being constructed in the ASEAN region with the aim of further developing demand. Better coordination between governments will help to push the construction of these pipelines faster and will be necessary for establishing the route and determining usage fees.

Promotion of natural gas use in the transportation sector should also be encouraged to develop future natural gas demand, but its success or failure will also depend on the development of infrastructure. In the Asia-Pacific market, if price differences between crude oil and gas continue, gas might have a chance to become an increasingly important transport fuel option in the future. In October 2016, at a special meeting of the International Maritime Organisation (IMO), a decision was made to regulate the sulphur content of international marine heavy fuel oil to less than 0.5% after 2020. Therefore, there is also the possibility that LNG, which contains almost no sulphur content, will be increasingly used by marine vessels. To achieve increased demand for transportation, it is necessary to enhance the convenience of natural gas vehicles and LNG carriers to consumers, particularly by installing natural gas-fuelling infrastructure. Governments can make
a significant contribution to promoting the use of natural gas in Asia if they concentrate on the development of LNG infrastructure in conjunction with policies promoting the number of natural gas vehicles and the adoption of LNG carriers.

**Reasonable pricing reflecting the supply and demand of gas**

In promoting the use of natural gas, it is also important to create a market mechanism in which prices are set appropriately reflecting the supply and demand of natural gas. As stated in Chapter 1, the relative competitiveness of LNG in the Asian market decreased dramatically as its price, which is linked to crude oil, was skyrocketed during the 2010s. Currently, many Asia-Pacific economies have a limited number of fields in which natural gas and oil are competing directly, and the LNG pricing method of linking to the price of crude oil is not based on economic fundamentals. In Asian markets, the establishment of gas prices that reflect supply and demand is possible, provided that there is an active spot market with high liquidity. To that end, governments need to strongly encourage the elimination of point of destination provisions in the long-term LNG contracts.

By reflecting gas’s lower emissions, a carbon pricing method that promotes gas use is also possible. In this respect, either emissions trading or a carbon tax can be considered as two sensible policy options. However, if the primary purpose of carbon pricing is to promote the use of natural gas and not reduce greenhouse gas emissions, it must be introduced carefully. As for emissions trading, the current experience in the EU, where economic stagnation has led to low marginal carbon price, ineffective policy design is an important warning. As for a carbon tax, although there is an advantage that a certain tax amount can be fixed in advance, there is the possibility that the scale of the taxation becomes too small or excessive depending on trends in coal and gas markets. Therefore, detailed study is necessary before the implementation of either of the above approaches.

**Increasing domestic production**

Finally, increasing domestic production can be assisted through policy decisions in economies that have existing natural gas resources. However, as mentioned above, investment in the upstream sector will only happen if domestic natural gas policy is clear and it can be adjusted to a level that properly reflects supply and demand. It is also possible to accelerate domestic natural gas development by making the license issuance a less arduous process with a high degree of transparency. Furthermore, in the Asia-Pacific region, there are economies with abundant shale gas resources, such as China, consequently any intergovernmental agreements that facilitate the transfer of technologies for the development of such unconventional gas will help to push forward the shale revolution outside North America.

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