Natural Gas Utilization in APEC:

Is the Golden Age of Gas Still Probable?

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APERC
Asia Pacific Energy Research Centre

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Foreword

Demand for natural gas has been in a slump in many economies despite its benefits. Gas emits much less carbon dioxide than other fossil fuels, it can be very efficient if advanced power generation technology is used and its resource base has expanded significantly thanks to the shale revolution. Based on these benefits, just five years ago it was largely expected that a "Golden Age of Gas" would be coming in the near future when the International Energy Agency (IEA) published a report titled "*Are We Entering a Golden Age of Gas?*".

Why did the Golden Age fail to materialise? This study will explore various factors that work against natural gas utilisation, from macroeconomic conditions to government policy and inter-fuel competition affected by global commodity markets. This study was jointly conducted by the Fossil Fuels and Electricity Industry Unit of the Institute of Energy Economics, Japan (IEEJ) and the Asia Pacific Energy Research Centre (APERC).

I would like to express my sincere gratitude to the authors and contributors to this study for spending time and effort in doing relevant research studies. However, I would like to emphasise that the contents and views in these independent research projects only reflect those of the authors and not necessarily of APERC. The contents and information from these studies might change in the future due to unforeseen external events, and the changes or improvements in the individual economy's policy agenda and framework on oil and gas security.

Takato OJIMI
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April 2017

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Abbreviation and Acronyms

Abbreviation

Bcm	billion cubic meters
Bcm/y	billion cubic meters per year
GW	gigawatts
MW	megawatts
TWh	terawatt hours
Ktoe	kilotonnes of oil equivalent
km^2	square kilometre
Mtoe	million tonnes of oil equivalent
Tcf	trillion cubic feet
Tcm	trillion cubic meters
Toe	tonnes of oil equivalent
USD	US Dollars

Acronyms

APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
CCGTs	Combined Cycle Gas Turbines
EGEDA	Expert Group on Energy Data Analysis
EIA	Energy Information Administration
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
PPP	Purchasing Power Parity
RGT	Regasification Terminal
TPES	Total Primary Energy Supply
US	United States

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Executive Summary

The golden age of natural gas was expected to arrive early in the 2010s—with both the supply and demand of natural gas steadily growing, energy prices stabilising and as a tool in mitigating climate change—but has yet to materialise. This report examines the challenges faced in increasing gas utilisation for numerous economies and the best approach to promote the use of gas in the Asia-Pacific and other regions by focusing on six case studies involving: Chile; China; Indonesia; Japan; United Kingdom and Viet Nam.

Based on this study, six main reasons have been identified as factors that hampered gas utilisation. The ***first*** reason is that the global economy did not grow as much as initially anticipated, particularly the European economy and emerging economies such as China, which resulted in flat growth in primary energy demand. ***Second***, natural gas has not been able to secure relative economic efficiencies in the power sector compared with coal. Many economies in the Asia-Pacific region have abundant coal resources, especially emerging economies, and with domestic energy demand expected to rapidly increase, coal has been the fuel of choice due to cost competitiveness. ***Third***, there is strong government support for renewable energy (many economies have policies promoting renewable energy as domestic zero-emission energy). Such protection has been successful and natural gas has not been able to expand its market share as expected in the power sector because the cost of renewable energy has been falling. The ***fourth*** reason has to do with business practices related to trading natural gas. Since natural gas requires expensive infrastructure for its supply, much of it is traded on long-term contracts. Since the price of LNG in Asia is linked to international crude oil prices, it rose with the price of oil until 2014 and the demand for LNG failed to increase because of its lack of competitiveness compared with coal and other fuels. ***Fifth***, there is a lack of infrastructure. Natural gas demand is realised only after the infrastructure is established on the consumer end. Although the potential scale of demand in the Asia-Pacific region is extremely large, the lack of progress on building public infrastructure is one reason demand is sluggish. ***Sixth*** is the decline of domestic production. In Indonesia, natural gas production has declined for economic and geological reasons, while in Viet Nam, gas demand is closely matched with domestic production. Since gas is expensive to transport, a decrease in domestic production can also lead to a decline in demand.

Based on the findings from the case studies in this report, there are four policy issues in promoting the use of natural gas. ***First*** is setting a desirable energy mix. Various factors determine an economy's energy mix, such as the price competitiveness of various energy sources, the stability of supply and its safety, and environmental compatibility. Based on these various factors, it is important for a government to clearly indicate the desirable energy supply balance. By explicitly indicating the position and character of the overall energy mix, such as the role natural gas is expected to play in a sector, businesses that supply gas will find it easier to invest in the gas business and acquire funding.

Second is the maintenance of infrastructure. It is a given that as the use of gas grows so does infrastructure, but even in Europe there are many cases where the government has contributed a certain amount of money to develop it. While it is possible to make it easier for such infrastructure investment to be made by clarifying the expected role of natural gas in the above-mentioned energy mix setting, it is still necessary to provide some degree of government financial support. Especially in promoting expanded use in the transportation sector, it is increasingly important to support infrastructure development with policies and packages for transportation, such as for the adoption of next-generation vehicles and LNG-powered ships.

The ***third*** issue is the reasonable pricing of gas. In Asia, most LNG continues to be sold at prices linked to the price of crude oil. However, in the first half of the 2010s, LNG was put at a great disadvantage in terms of competitiveness as the price of crude oil soared. Even in Asia, it is necessary to establish price indicators that reflect the supply and demand of natural gas in a timely manner, and pricing schemes through the establishment of spot LNG trading. From the viewpoint of price competitiveness relative to coal, introducing carbon pricing can be an effective method. However, careful preparation is necessary to create an effective system as there are cases in Europe, for example, where emissions trading has already been introduced but the expected effect was not initially obtained.

Fourth and finally, there is reinforcing supply capacity. If the supply within a region increases and if it is directly exported, the use of gas will expand within the region. To this end, through policy actions such as speeding up and making transparent decision-making on upstream development, and promoting the introduction of technology from overseas, it is possible to improve the entry conditions for foreign-owned enterprises.

CHAPTER 1

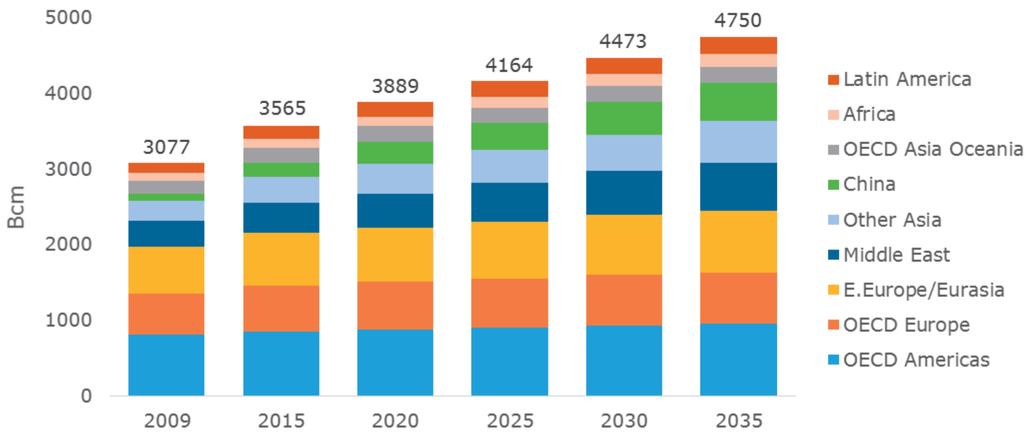
DEFINING THE GOLDEN AGE OF GAS

What is the Golden Age of Gas?

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

A simple definition of the golden age of natural gas is that both the demand and supply of natural gas markedly expand at a stable price. This phrase spread through the energy industry with the publication of a report in 2011 by the IEA. In this 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 1.1), 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.

Figure 1.1 • Demand forecast in the IEA's "Golden Age of Gas" scenario, 2009-30

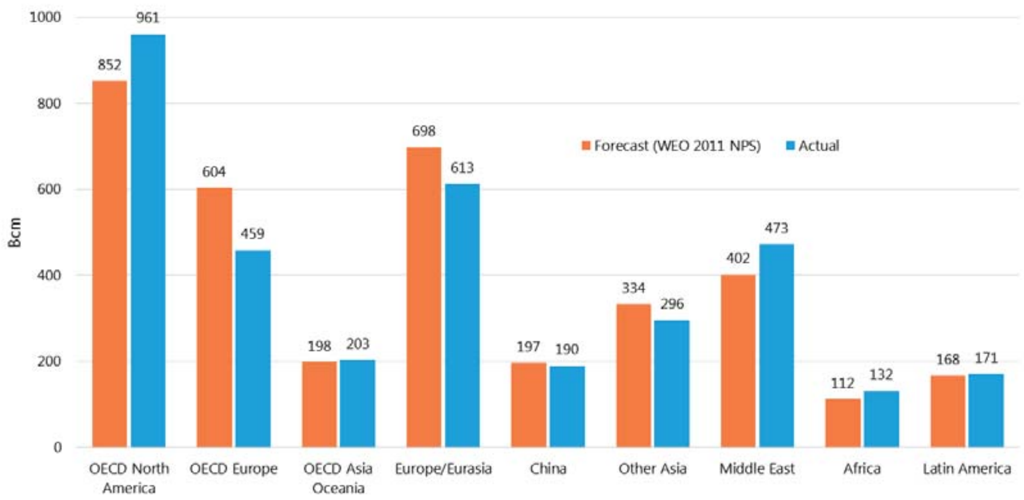


Source: IEA (2011)

Actual natural gas demand

Although there were high expectations for natural gas demand, actual demand growth differed greatly by region. Figure 1.2 compares the demand estimated as of 2015 in the above "Golden Age of Gas" scenario with the 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 the "Golden Age of Gas" scenario. There was a large difference between the forecast and actual results in Europe and other Asia, and the situations in these economies highlight the fact that the arrival of the golden age did not spread globally.

Figure 1.2 • Forecast and actual demand of the "Golden Age of Gas" scenario, 2015



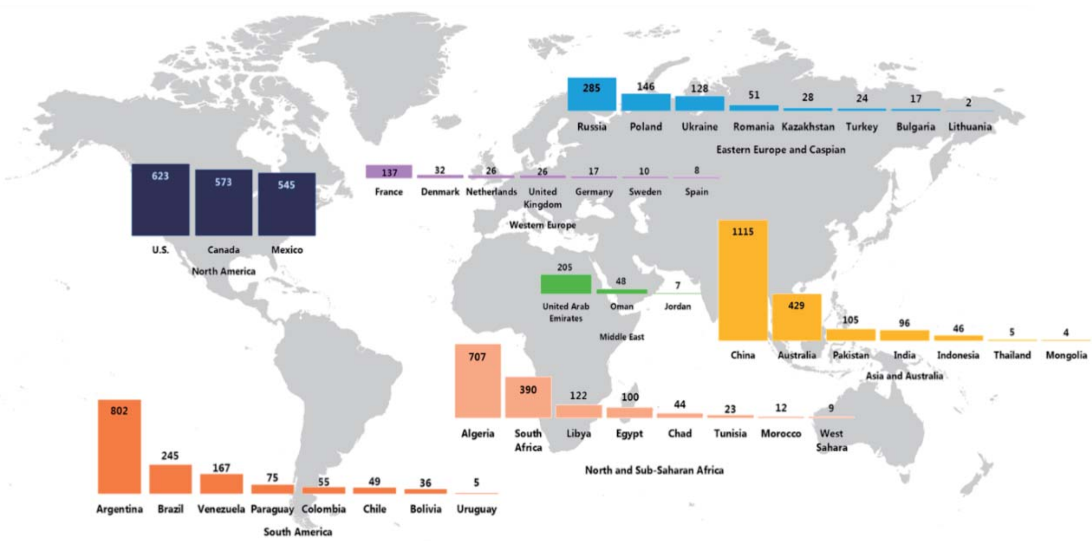
Source: IEA (2011) and Cedigaz (2016)

The basis for the arrival of the golden age

Shale revolution

As of 2011, there were several reasons for robust expectations that the "golden age" would materialise in the future, chief amongst which as the shale revolution in the US. Figure 1.3 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 outside North America. In addition to economies that are evaluated in the figure, there are many shale resources, for example, in Middle Eastern oil-producing economies. With the shale revolution, resources shifted from being "scarce" to being "abundant". The possibility of peak production in natural gas in the near future because of geological resource restrictions has been greatly pushed back by the shale revolution.

Figure 1.3 • Global technically-recoverable resources for shale gas, in Tcf, 2015

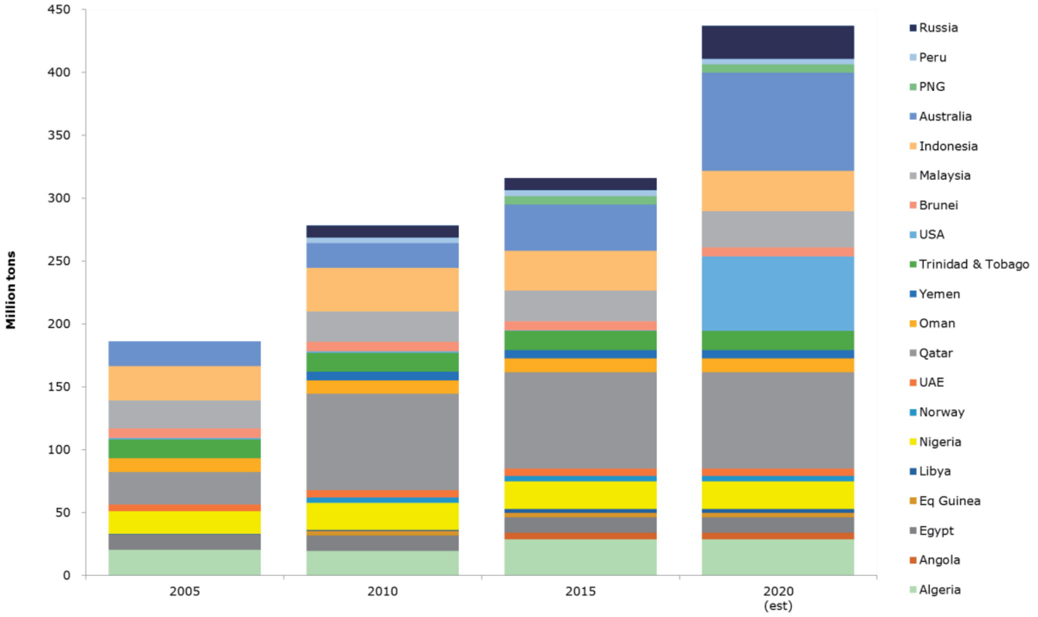


Source: EIA (2015)

Rapid increases in LNG production capacity

Another factor is the rapid increase in LNG production capacity. The world's LNG production capacity of 186.3 million tons in 2005 expanded to 315.8 million tons by 2015, a 1.7-fold increase driven by greater capacity in Australia, Qatar and other economies. LNG production capacity is forecast to increase to 437.1 million tons by 2020 (Figure 1.4). This capacity expansion was expected to greatly contribute to the materialisation of the golden age.

Figure 1.4 • Global LNG production capacity, 2005-20



Note: 2020 figures are estimated by IEEJ
Source: GIIGNL (2016)

Change in attitude toward nuclear power generation

Another factor expected to increase gas demand is the changing attitude towards nuclear power generation after the March 2011 accident at the Fukushima Daiichi Nuclear Power Plant, which triggered a strong worldwide reaction to the impact 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, all nuclear power plants had been shut down in 1990 following the Chernobyl accident, but a referendum on resuming the operation of these plants that took place in June 2011 resulted in 90% of the votes being against re-starting operations. It is widely accepted that these events were possible in European economies because of the highly integrated network there.

Recently, Chinese Taipei decided to shut down nuclear power plants. Ms. Tsai Ing-Wen, who became president in May 2016, is promoting a plan 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 trying to distance themselves from nuclear power, gas demand is 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 energy source among fossil fuels. 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 only emission reductions target that was 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 solve China's environmental problems, 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 also has a target of raising the proportion of natural gas from 5.2% as of 2014 to 15% by 2030. Addressing these environmental problems was also supposed to be a factor that ensured future increases in natural gas demand.

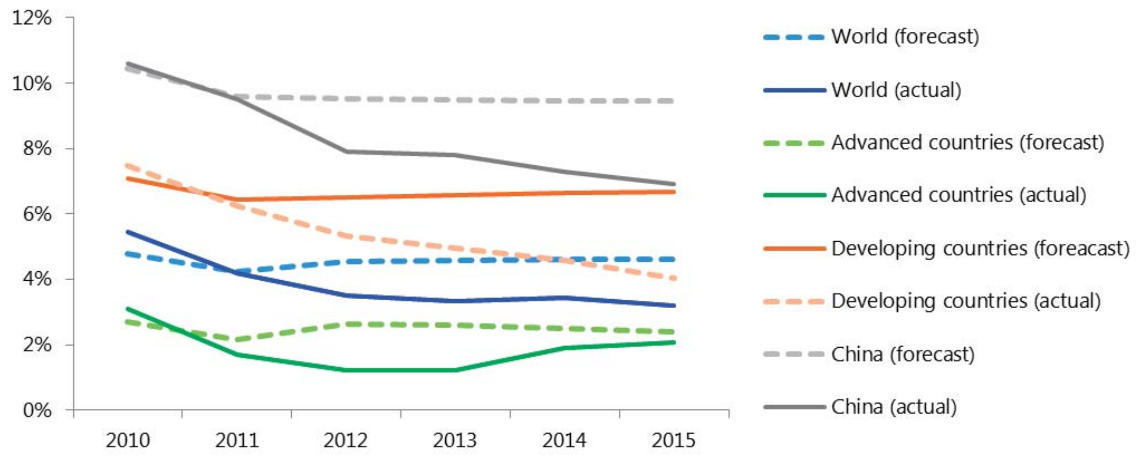
Why did the "Golden Age" fail to materialise?

There were great expectations that a golden age of natural gas would materialise, but except for the United States and a few other economies, why did it not happen? There are six main reasons.

Macroeconomic slump

One reason is 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 higher range around 6%. However, Figure 1.5 shows that the actual economic growth rates were not as high as initial expectations. Europe had the largest discrepancy in the growth rate as the unexpected slump in the economy let loose several economic problems, such as Greece's financial crisis, and had the effect of reducing the demand for natural gas. Even China's growth rate has been slowing slightly since around 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.

Figure 1.5 • Economic growth rate outlook as of 2011 and actual growth rate, 2010-15



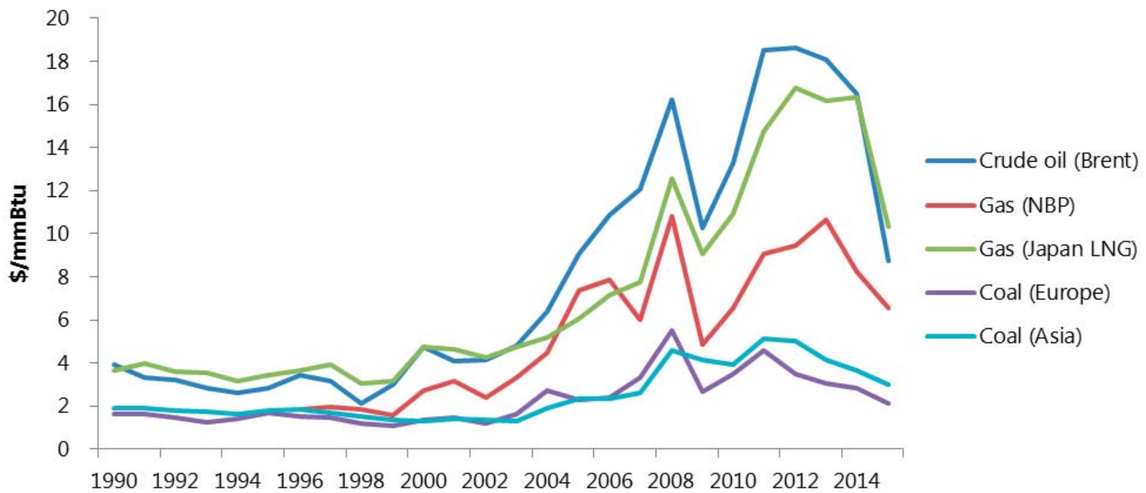
Source: IMF (2011) and (2016)

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, such as coal in the power generation sector. Coal emits more harmful substances, such as carbon dioxide, than natural gas, but it is generally less expensive than natural gas.

Figure 1.6 shows that coal prices have always been lower than oil and natural gas. In the United States, where the shale revolution has advanced, coal and natural gas prices are at nearly the same level, and this has led to an increase in coal exports from the United States until 2012 and the relaxing of international coal demand and supply, which has contributed to the slump in international coal prices.

Figure 1.6 • Change of the relative prices of coal, LNG and oil, 1990-2014



Source: IMF (2017)

In emerging Asian economies where energy demand is currently growing such as China, India, Indonesia and Viet Nam, coal continues to be the preferred fuel because of abundant resources and cost. Natural gas not only has a high price but also requires the development of infrastructure such as pipelines, so in economies where energy demand is rapidly growing, gas has a lower priority than coal when it comes to choosing an energy source.

Similar circumstances exist in East Asian economies such as Japan and Chinese Taipei. 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 from the viewpoint of securing 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.

China, India and other economies are developing policies to limit the use of coal in response to environmental problems. Since coal provides around 70% of the China's energy supply, there are many people dependent on coal related jobs. For this reason, although the government is trying to restrict the use of coal, making policy change is challenging.

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, though in recent years, the traded carbon price has been low. It was originally assumed that this carbon price would rise to a certain level, thereby restricting the use of coal, which emits more carbon dioxide, but in reality, energy demand itself decreased during an economic downturn, which reduced the price of carbon (Figure 1.7) and had little effect on curbing coal use.

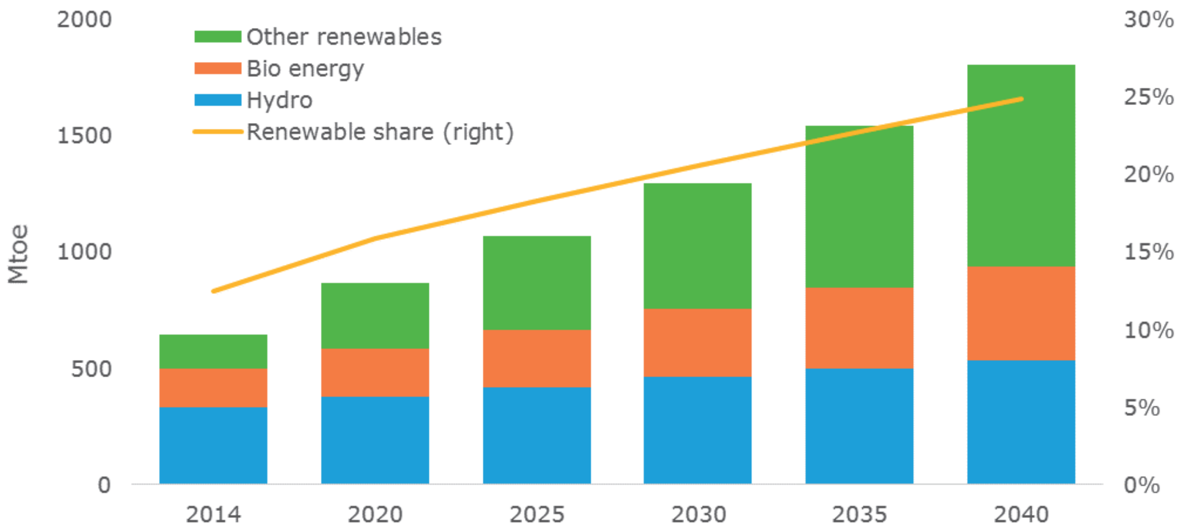
Figure 1.7 • EU carbon price, 2010-16

Source: ICE (2017)

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 (Figure 1.8) and APERC, renewable energy is expected to have the highest rate of growth in the future energy mix.

Figure 1.8 • Projected share of renewable energy in global power generation, 2014-40



Source: IEA (2016b)

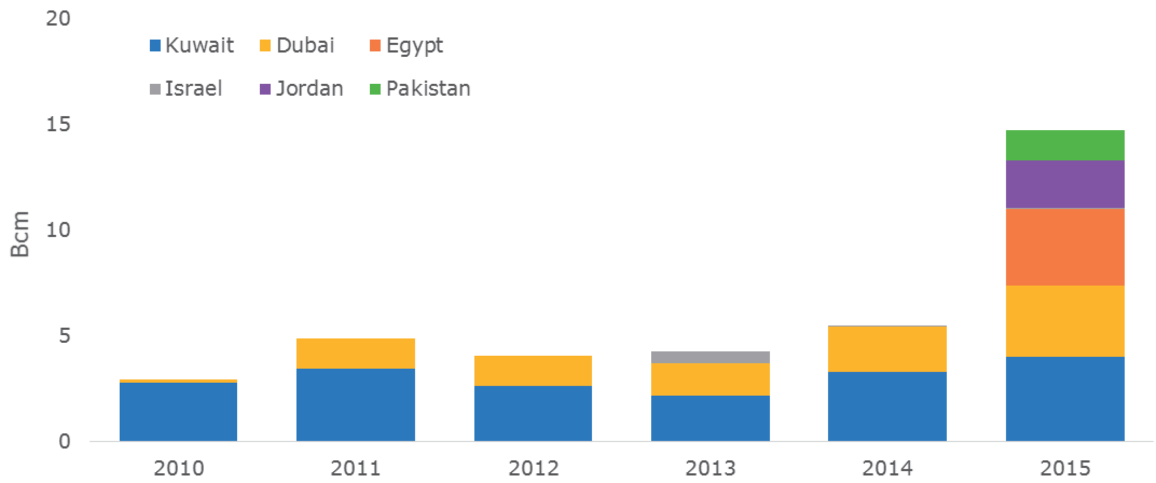
With the government supporting renewable energy, natural gas is at a relative disadvantage (despite sometimes having superior cost competitiveness) and is unable to increase its demand share. With respect to solar photovoltaic (PV) in particular, the production of panels has increased because of policy 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 of more than 10 years but the price of the contract is determined by linking it to the crude oil price. This is because LNG was originally used as an alternative fuel to oil. Since 2010, LNG prices rose alongside crude oil when oil surpassed $100/barrel, which hampered the development of new demand, especially in emerging economies.

The fall of crude oil prices in the latter half of 2014 led to a decline in contracted LNG prices, which has resulted in the development of new demand in the Middle East and South Asia (Figure 1.9). Although the capacity of these emerging LNG importers continues to expand, it is currently only around 10 million tons, which is relatively small compared with the world demand for LNG (250 million tons), and insufficient to compensate for the overall sluggishness of global demand for natural gas.

Figure 1.9 • LNG import volume in the Middle East and Pakistan, 2010-15



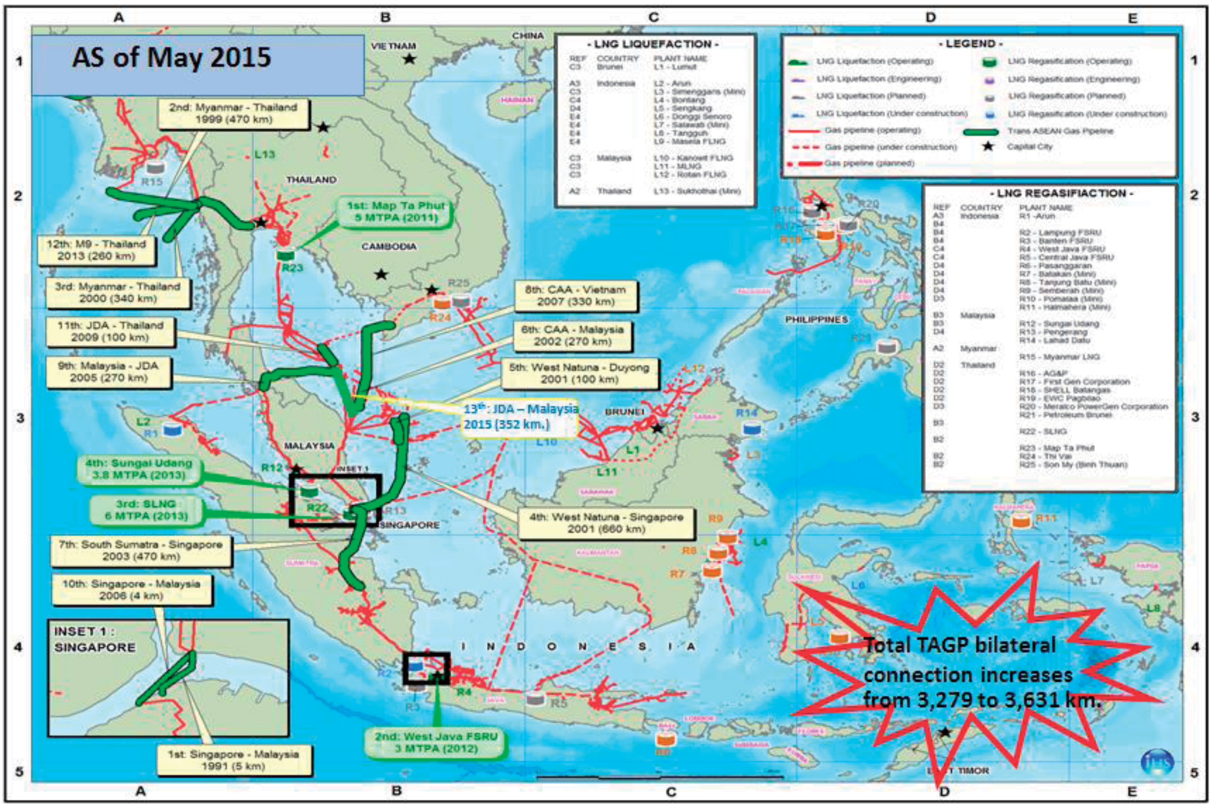
Source: Cedigaz (2016)

The adverse effects of linking the price of LNG to crude oil have led to a movement in Asia to create an alternative price index to reflect LNG supply and demand. 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 huge role in meeting 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 as much 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 is potentially large, but with no developed pipeline network, the potential 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 (Figure 1.10), no major progress in construction has been made as economies in the region start to shift from building trans-border pipelines to LNG imports. The development of such infrastructure sometimes needs to be treated as a public good which means some kind of support from government is necessary, but has not always been provided fully.

Figure 1.10 • Trans ASEAN Gas Pipeline concept, 2015



Source: ASCOPE (2017)

Production constraints

In some economies, declining production limits gas demand growth. For example, the production of offshore gas in Indonesia has not reached the originally planned scale, leading to sluggish domestic demand. Figure 1.11 shows the growth in domestic demand is directly reflected in domestic production growth as seen in Viet Nam and Indonesia.

Figure 1.11 • Natural gas production and demand in Viet Nam and Indonesia, 2008-14

Source: IEA (2016a)

Because of the six factors mentioned above, global natural gas demand has not displayed as much growth as originally expected. The following chapters will review the current state of natural gas usage in six major economies and the issues surrounding the expansion of future use.

CHAPTER 2

CASE STUDY: CHILE

Introduction

Chile is located in the southwest of South America. It shares borders with Peru to the north, and Bolivia and Argentina to the west. Its coastline runs along the Pacific Ocean for 6 435 km, with an average width of 175 kilometres (km) and a land area of 756 102 square kilometres (km^2). Administratively, Chile is divided into 54 provinces and 15 regions headed by regional governors (Intendente) appointed by the President. By 2014, the economy's population was around 18 million, with 87% living in urban areas and 40% percent of the population in the Metropolitan Region (RM) containing Santiago, the capital (INE, 2014).

Chile's economic growth is based on solid macroeconomic fundamentals, such as fiscal responsibility, an independent central bank with an explicit inflation target and a floating exchange rate system. Chile has almost tripled its gross domestic product (GDP) per capita from USD 8 175 in 1990 to USD 19 438 in 2014 (2015 USD purchasing power parity [PPP]) (Table 2.1). It is one of the fastest growing economies in South America with an average annual growth rate (AAGR) of 4.9% between 1990 and 2014. In 2014, Chile's GDP reached USD 344 billion (2015 USD PPP), which represents an increase of 1.7% from 2013 levels. Foreign direct investment, closely related to mining investment, decreased by 35% to USD 17 billion in 2014 owing to lower commodity prices (UNCTAD, 2015). Chile's economic activity is highly correlated with final energy consumption, where the mining and industry sectors accounted for 45% of final energy consumption in 2014 (IEA 2015) and represented around 24% of Chile's economic activity (INE, 2015). Almost 95% of the total exports were under trade agreements with 60 economies, including the European Union, Mercosur (a regional trade group comprising Argentina; Brazil; Paraguay; Uruguay and Venezuela), India, China, Japan, Korea, Mexico and the United States (DIRECON 2015).

Table 2.1 • Chile key data and economic profile, 2014

Key data[a]		Energy reserves[b, c, d]	
Area (km^2)	756 102	Oil (million barrels)	1.9
Population (million)	18	Gas (million cubic metres)	9
GDP (2010 USD billion PPP)	354	Coal (million tonnes)	171
GDP (2010 USD PPP per capita)	19 895	Uranium (kilotonnes of U)	3.7

Sources: a. EGEDA (2016); b. MEC (2015); c. EIA (2016); d. CCHEN (2013).

According to APEC's Expert Group on Energy Data Analysis 2015 (EGEDA), Chile's TPES decreased by 6.7% from 2013 to 2014 to reach 36 061 Ktoe. Approximately 45% of this energy volume was supplied in the form of crude oil and its by-products, 18% as coal, 10% as natural gas and the remaining 26% from other sources, particularly renewables and hydropower. Given its limited hydrocarbon resources, Chile is a net importer of primary energy, especially fossil fuels. Net primary energy imports represent 66% of the TPES, having fallen by nearly 6% from 2010 to reach 24 293 Ktoe in 2014 (EGEDA, 2015).

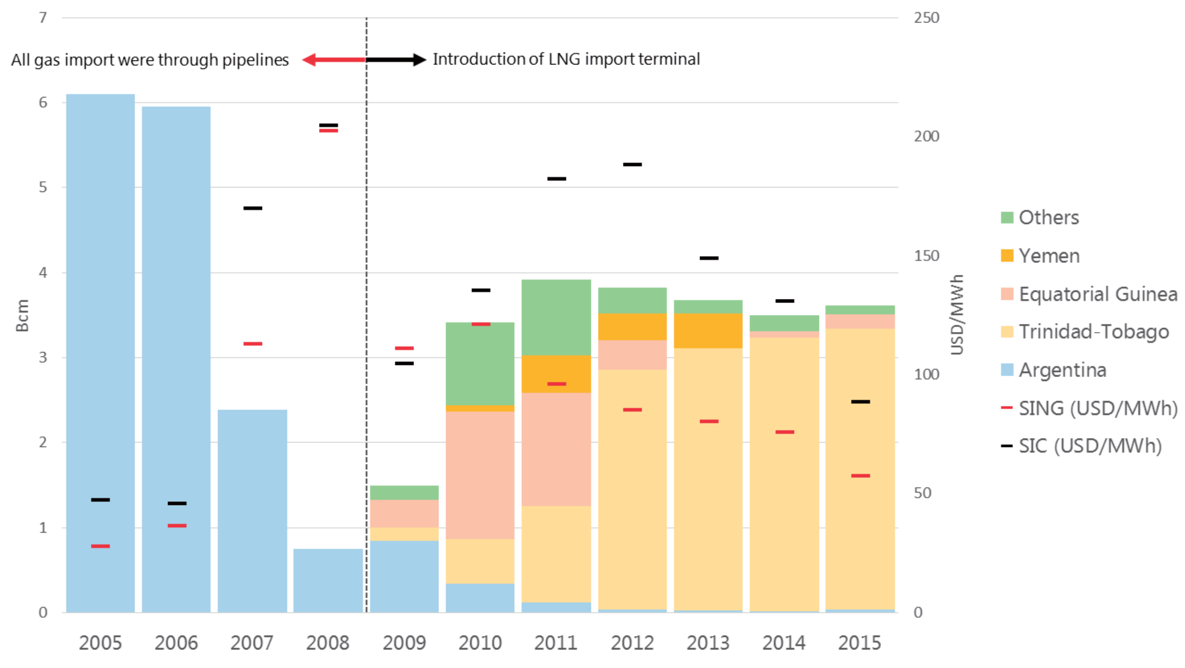
Due to its geography, Chile's electricity system is divided into four major grids which are Northern Grid (SING), Central Interconnected System (SIC), Magallanes Grid (located at the southernmost part of Chile) and Aysen Grid which located between SIC and Magallanes Grid. The SIC and SING together account for 99% of the economy's electricity capacity covering the 98% of Chile's population.

Natural gas in Chile

The use of natural gas in Chile began in 1971 when the National Petroleum Company (ENAP) developed its own reserves located in the Magallanes region (in the South). Although Chile has limited gas reserves, the government encouraged the residential and industrial sectors to use gas by introducing legal frameworks in 1989, which allow Chile to import gas from Argentina. Argentina started exporting natural gas to central Chile in 1997, followed by exports to the north in 1999. However, gas supply from Argentina (all via pipelines) fell significantly from 6.1 Bcm in 2005 to 0.75 Bcm in 2008 due to Argentina's economic crisis within the same time frame (Cedigaz, 2016).

Chile was badly affected by the sudden import curtailment, this can be seen in power generation costs, which increased from USD 28/MWh in the Northern Grid (SING) and USD 47/MWh in the Central Interconnected System (SIC) in 2005 to USD 203/MWh and USD 205/MWh in 2008 respectively (Figure 2.1).

Figure 2.1 • Power generation cost and natural gas imports in Chile, 2005-15



Source: Cedigaz (2016), CNE (2015) and APERC Analysis

As part of the efforts to have a reliable gas supply and a diversified energy mix, two regasification terminals located in the regions of Valparaiso (Centre) and Antofagasta (North) have been built. The Quintero terminal (Valparaiso), began its operations in 2009 with a regasification of capacity of 4 MTPA, while the Mejillones terminal located in Antofagasta has capacity of 1.5 Mtpa (IGU, 2016). Its main supplier is BG Group, with a 21-year contract for up to 1.7 million tons per year (BG, 2015). The Mejillones terminal (Antofagasta), is partnered by Codelco[1] and GDF Suez.

Policies, regulatory frameworks and governance structure

In order to develop its economy, Chile opened its market in the 1980s and today it is well entrenched in the international trade ecosystem by upholding free market principles. It has reaped the benefits as the economy has grown significantly. From the 1980s to 2013, Chile has more than doubled its income per capita and has been one of the fastest growing economies in Latin America. In addition, it provides a business environment conducive to foreign investments, given its streamlined administrative processes and simplified tax payments. Chile is ranked 34 among 183 economies in the report Doing Business 2014.

As an open-market economy, Chile is highly integrated with world markets. Its participation in free trade agreements has increased its options for sustainable development, as evidenced by increased trade opportunities, reduction of its dependency on mineral exports and creation of trade products with higher value-added. In line with these principles, Chile's energy policy is based on the development of a free market approach towards enhancing its economic efficiency and energy security by reducing its vulnerability to supply shocks and high dependence on imports.

The Chilean Parliament approved the creation of a Ministry of Energy in November 2009 which is tasked to develop, propose and evaluate energy policies. Among notable policies developed by this Ministry is "Energy 2050", which was released in December 2015 and comprises of four pillars: energy security and energy supply quality; energy as a development engine; environmental compatibility; and energy efficiency and education (MEC, 2015). Furthermore, the government has implemented mid- and long-term goals to guide policy actions setting measurable indicators, action plans, and actors involved in each stage of its implementation (Table 2.2).

Chile has a long history of gas regulation. The Gas Service Act was enacted in 1931, and has remained in force through 2016 with some modifications. According to the Ministry of Energy, current regulations are not adequate to cope with future demands due to lack of important provisions such as (MEC, 2016b):

- A price setting mechanism;
- Assessing companies' "rentability";
- The method for calculating the fair capital cost rate (CCR);
- Mechanism for dispute settlement between the regulatory agency and gas distribution companies.

[1] Codelco: National Copper Mining Company. A state-owned company and the largest copper producing company in the world.

Table 2.2 • Chile's Energy 2050 main goals, 2035 and 2050.

Chile's Energy 2050	
Goals by 2035	**Goals by 2050**
Interconnection with members of the Andean Electric Interconnection System and with other South American economies (particularly Mercosur members)	GHG emissions in the energy sector will be under the limits established in the economy-wide goal.
Energy disruption reduced to less than four hours per year.	Energy disruption reduced to less than an hour per year.
Continuous and reliable access to energy services for all new vulnerable dwellings.	Universal and equitable access to reliable and modern energy services.
All projects developed have associativity mechanisms between project developers and communities to foster local development and better performance.	Territorial, regional and local planning and management tools conforming to the energy policy are in place.
Be among the five OECD economies and countries having lowest residential and industry energy costs.	Be among the three OECD economies and countries having lowest energy costs.
At least 60% of electricity generation is from a renewable sources	At least 70% of electricity generation is from renewable sources
30% emission intensity reduction in comparison with 2007.	Energy consumption decoupled from GDP growth.
All large energy consumers to apply energy efficiency measures.	100% of new buildings constructed under the OECD standards of efficient construction and smart systems of energy management.
All municipalities to adopt regulations declaring traditional biomass as solid fuel, thus included in GHG emissions levels.	100% of the main categories of appliances in the Chilean market are energy efficient.
All new passenger vehicles to be evaluated under energy efficiency standards.	Energy efficiency practiced at all levels of society.

Note: OECD - Organisation for Economic Co-operation and Development.
Source: MEC (2015) and APERC (2016).

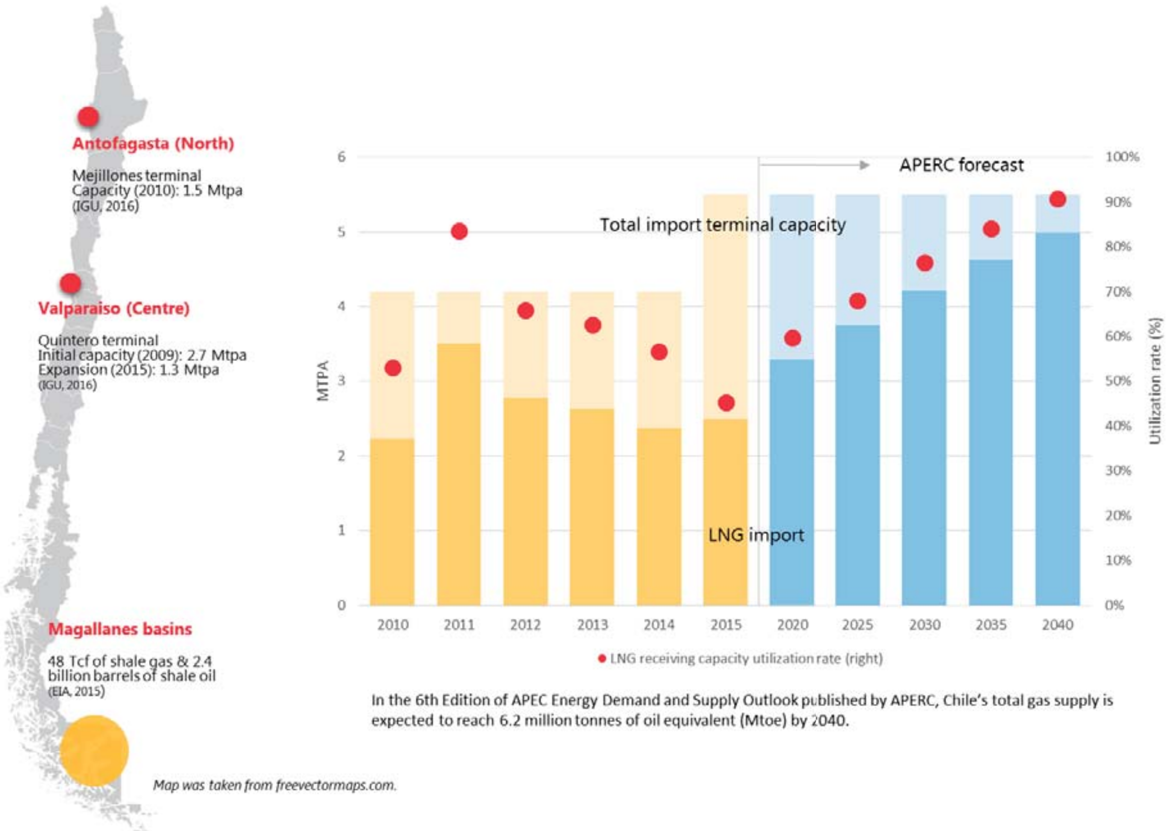
Exploration and production

Despite the diverse geography and abundant natural resources, the economy has very limited fossil fuel resources, making Chile a net energy importer. Recognising that Chile is heavily dependent on energy imports, the government has outlined many strategies to reduce import dependency without jeopardising energy supply. Around 65% of total primary energy supply (TPES) in 2013 was imported (98% of oil and 71% of gas supply). Despite high oil and gas import dependence, hydro and biomass contributed about 30% of TPES in 2013 (EGEDA, 2016).

Oil production declined from 15 million barrels in 1981 to 1.1 million barrels in 2013 (Agostini and Saavedra, 2009; ENAP, 2014) while gas production reached its peak in the 1970s with production of 4.1 Bcm and subsequently declined to 1 Bcm in 2015 (Cedigaz, 2016). The government is currently focusing on exploration investment through the ENAP, with investment in exploration expected to reach USD 800 million per year by 2020 (ENAP 2014).

Since Chile has very limited gas production, and has been impacted by pipeline gas supply disruptions in the past, two regasification terminals were introduced (as discussed earlier). Based on the 6th Edition of APEC Energy Demand and Supply Outlook published by APERC, these terminals are expected to have enough capacity to cover natural gas requirements until 2040, reaching a utilisation rate of 90% by then (Figure 2.2).

Figure 2.2 • Chile unconventional gas reserves, LNG import capacity and gas demand, 2010-40



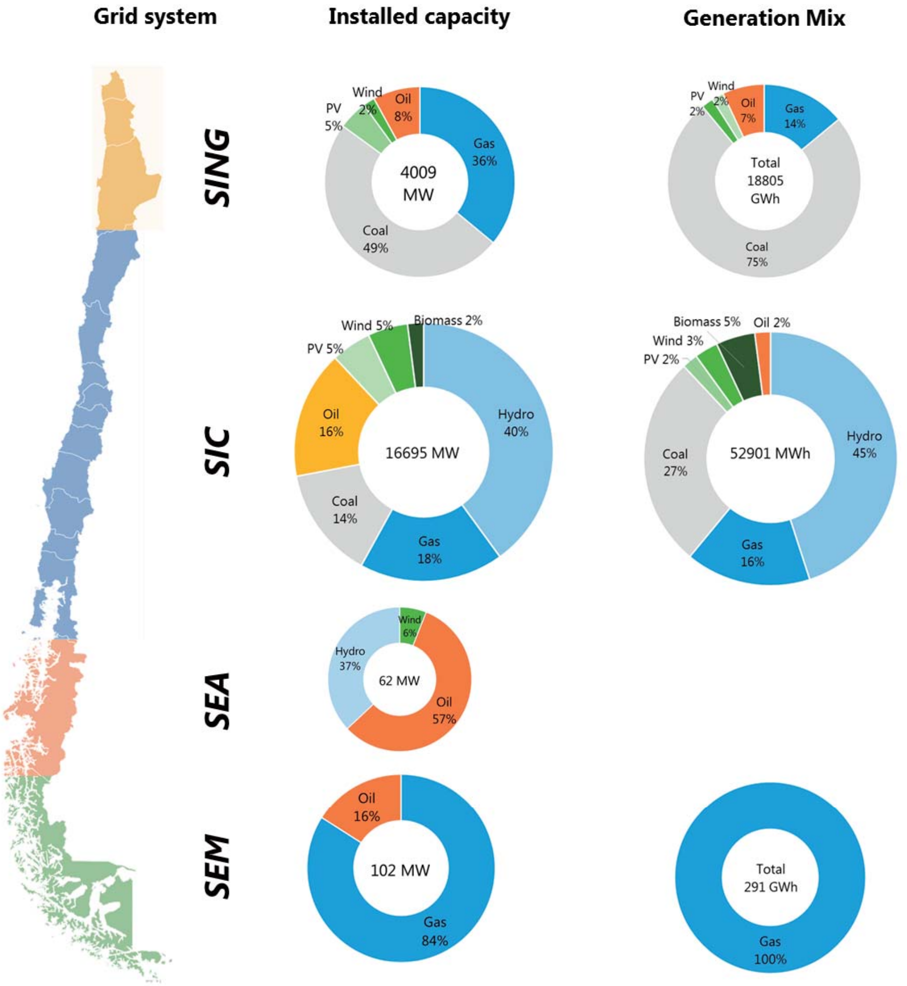
Source: IGU (2016), EIA (2015), IEA (2015), APERC (2016) and APERC Analysis

Despite limited gas resources, Chile is endowed with unconventional gas deposits located in the Magallanes basins. Based on EIA estimates, Chile has around 48 trillion cubic feet of shale gas and 2.4 billion barrels of shale oil and condensate that are technically recoverable (EIA, 2015) (Figure 2.2). ENAP, the national oil company, together with ConocoPhillips, an international oil company, has announced plans to explore unconventional gas in Southern Chile (Energia16, 2016).

Gas demand

In 2016, Chile's overall net installed electricity capacity was 20 868 megawatts (MW), with thermal power plants representing 56% of total capacity, hydropower 31% and other renewables 12% (CNE, 2016) (Figure 2.3). As mentioned previously, Chile's electricity system is divided into four major grids: the Northern Grid (SING), Central Interconnected System (SIC), Magallanes Grid and Aysen Grid. In 2013, 51% of gas demand came from the power sector followed by industrial sector (17%), residential (13%) and refineries and own-use (20%). This is an increase of nearly 20 percentage points for power when compared with the 2000 level.

Figure 2.3 • Electricity generation systems in Chile, 2016



Source: CNE (2016)

The SING system is the major power supplier for the mining sector (especially copper production), accounting for 85% of total electricity demand in the northern region. While, the SIC system is the major supplier to 92% of Chile's population, of which 60% of demand is from residential and small industries with tariffs regulated by the government. The remaining customers in the SIC grid negotiate their tariffs directly with power companies, since they are out of the scope of government regulation.

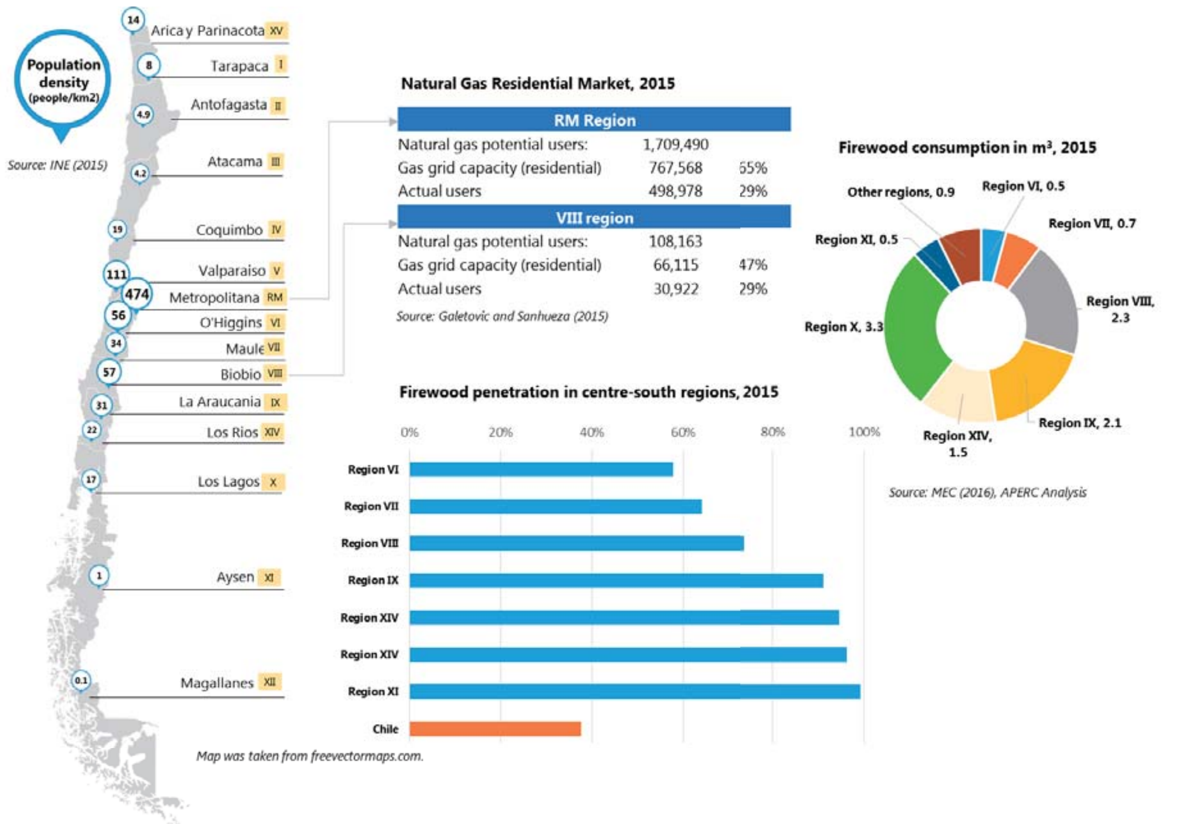
Besides power generation, residential is another sector where gas demand is expected to grow. Residential total final energy demand is expected to grow 3% annually from 0.4 Mtoe in 2013 to 0.9 Mtoe in 2040 (APERC, 2016). By 2020, six of Chile's 15 regions are projected to have populations of more than 1 million which in return, will push energy demand in residential sector higher (APERC, 2016). Gas accounted for 6.6% (0.4 Mtoe) of residential demand in 2013 and is projected to reach 11% by 2040 (0.9 Mtoe) (APERC 2016).

Although APERC projects residential sector gas demand to continue growing, there are challenges. A limited gas distribution network, a higher market share of LPG and wide use of firewood for heating and cooking in the central-south regions (where it is cooler and forests are abundant) may hamper gas demand (Galetovic and Sanhueza, 2015).

In two main regions, where the gas distribution network is considered well entrenched, the number of actual users of gas is less than one-third of the total potential residential users in that region. In 2015, the RM region where Santiago, Chile's capital is located, only the 65% of potential users have access to the natural gas distribution grid, and only 29% are actual users while in the Biobio region (region VIII), only 47% of potential gas users are connected to the distribution grid with a take up rate around 29%.

Almost 81% of the total energy in heating is for firewood and cooking (MEC, 2016a). In 2015, nearly 12 million cubic metres of firewood were consumed by the residential sector, with 93% of the consumption in centre-south regions (Figure 2.4). However, when it comes to firewood consumption, existing legislation does not consider the internalisation of environmental costs of emissions from firewood (fine particulate matter), which affects the quality of life of residents in areas where firewood is the primary source of energy.

Figure 2.4 • Natural gas and firewood usage in Chile's residential sector, 2015



Source: Galetovic and Sanhueza (2015), INE (2015), MEC (2016) and APERC Analysis

LPG is distributed through private networks or individual tanks (Figure 2.5). If there is no gas network available, consumers can buy individual LPG tanks. Due to well-established LPG networks and flexible supply (via pipes or tanks), LPG distribution companies have managed to keep LPG prices at a very competitive level compared with gas. Therefore, the only way for natural gas to get a bigger share in the market is by concentrating on high density areas, where the cost of building a gas network can be shared across a higher number of consumers. Even so, construction cost usually represents about half of natural gas cost for households (NaturalGas.org, 2013).

Figure 2.5 • LPG distribution options in Chile

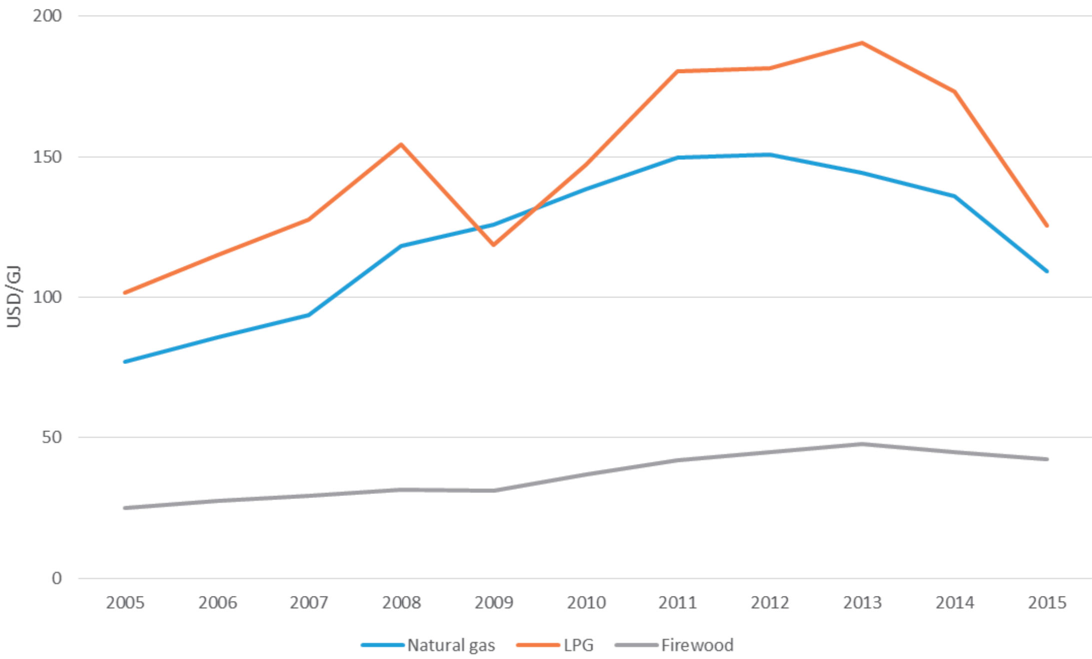
Source: MEC, 2016b.

For safety reasons, the government does not allow LPG tanks greater than 11 kilograms to be stored in residential buildings. Therefore, energy distributors are left with a single option, which is to supply LPG or natural gas through pipelines. Though this situation can push for higher natural gas penetration in areas with highly dense population, decisions on the type of energy source that will be supplied to a new development area fall solely on the project developer.

Energy price competition

Besides infrastructure and population distribution, cost competitiveness is one of the main factors that impacts gas usage in Chile. In terms of cost for a unit of energy, natural gas has an advantage compared with LPG (Figure 2.6). However, when compared with the cost of firewood, biomass is more than 50% cheaper. This price difference explains the high demand for firewood in the central-south regions of Chile replacing the use of LPG and natural gas.

Figure 2.6 • Fuel cost per GJ in Chile, 2005-15

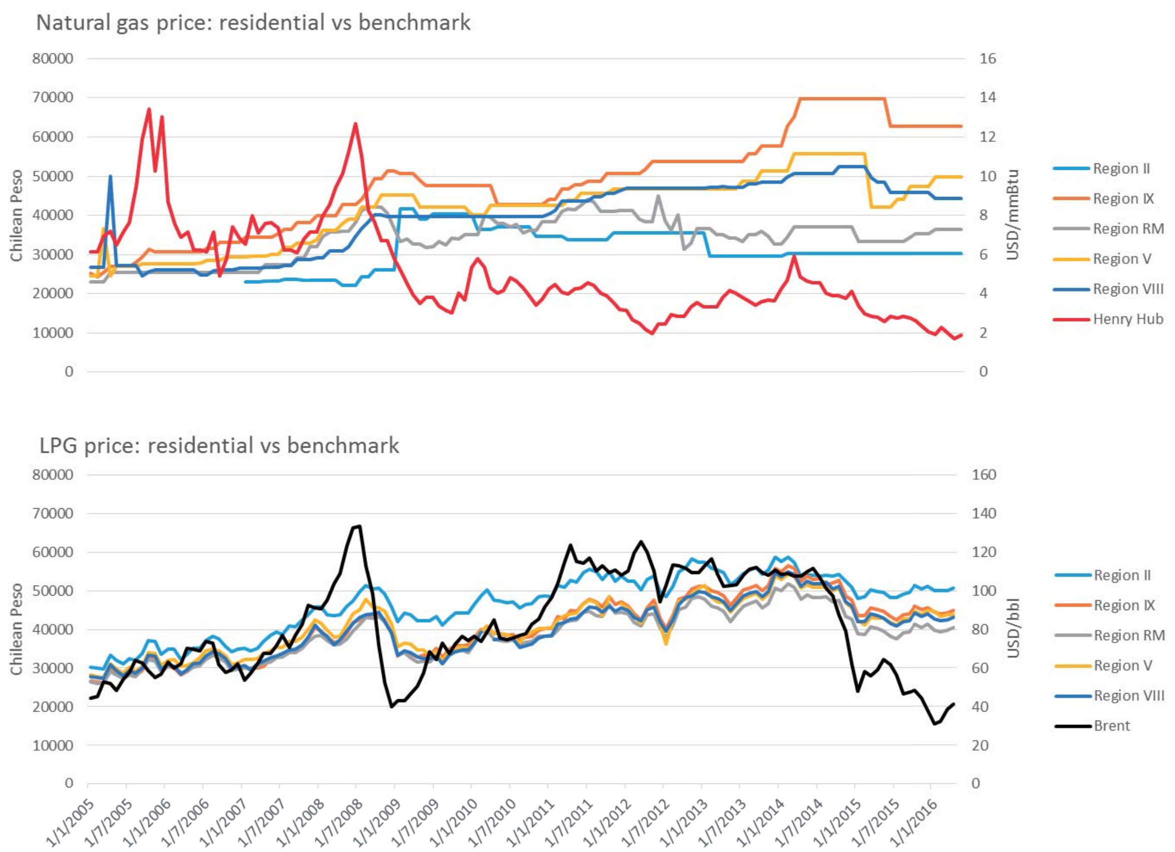


Source: CNE (2015) and APERC Analysis

Besides the cost of buying energy, the consumer may need to consider other external costs such as connection cost or transportation cost. On top of that, consumers will be charged with additional costs to switch from LPG to natural gas. Conversion cost of about USD 900 include the connection cost from the natural gas grid to the residence, gas meter, and residential distribution network, conversion of equipment and home appliances, and inspection and approval to obtain a low emission seal (Metrogas, 2016).

Based on APERC analysis, the price of LPG for residential consumers closely follows international crude oil benchmarks but not those for natural gas (Figure 2.7). The residential price of natural gas diverged from international prices of natural gas in 2008 and continue to be decoupled until 2016. The main reason is pass-through components. According to the Ministry of Energy, price movements actually increased financial margins for natural gas suppliers which in turn negatively affected final consumers (MEC, 2016b).

Figure 2.7 • Price of natural gas and LPG in Chile, residential vs benchmarks, 2005-15



Source: CNE (2015) and APERC Analysis

In order to rectify this issue, the government has proposed new legislation to regulate investment returns on natural gas companies, allowing a better pass-through between international and local prices, setting a limit on the utility margin to natural gas companies.

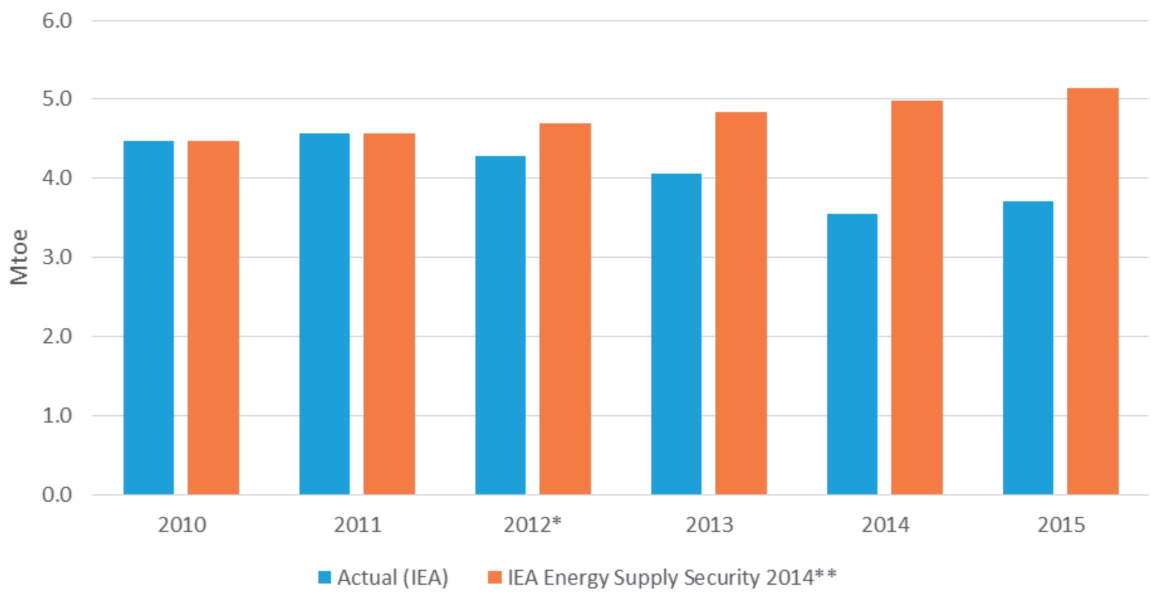
The government plans to maintain the free movement of gas prices (according to the world market price) but set a cap rate of return for gas companies that is equivalent to the Capital Cost Rate plus a spread of 3%. The Capital Cost Rate shall be reviewed every four years by the National Energy Commission (MEC, 2016a).

Past gas supply projections and actual supply

The golden age of gas was first declared by International Energy Agency (IEA) in 2011. In that year, IEA released their flagship publication – *World Energy Outlook 2011* with special report titled '*Are we entering a golden age of gas?*' Although the report was focusing on the North America shale gas boom that started around 2007-08, the question posed by IEA can be extended to other economies such as Chile. Therefore, a comparison between actual data and projections made in 2012/13 is needed in order to determine gas development in Chile (Figure 2.8). For comparison purposes, this study utilised past forecast data from Energy Supply Security 2014 publication (IEA, 2014).

The IEA's 2012 projections on gas demand in Chile were higher than actual data by nearly 30% by 2015. Regardless of the comparison results, the answer to the golden age of gas question posed by IEA is quite clear. At least for now, Chile has not yet entered the golden age of gas but that may change as unconventional resources are now beginning to be developed.

Figure 2.8 • Actual and projected gas demand in Chile, 2010-15



Source: IEA (2016) and IEA (2014).
Note:
**Demand in forecast bar is based on estimate (at the point when report was published).*
*** This publication provides Chile's previous gas forecast for 2012-2018. Since this publication does not provide yearly data (for 2013-2015), APERC used the CAGR derived from the forecast demand to determine 2013-2015 data.*

Factors contributing to lower gas demand

As discussed previously, cost plays a large role in consumer fuel choices. Although natural gas is generally lower than LPG in terms of cost per unit of energy, additional costs incurred for fuel switching allows LPG, which is entrenched, to dominate the market. Firewood is considered a natural choice for consumers who live in the centre-south regions. With cheap and abundant firewood and lack of gas supply infrastructure in these regions, gas penetration will continue to be low. In the power sector, with a target of 60% electricity generated from renewables by 2035 and 70% by 2050, gas demand may not increase in the future.

Lack of market oversight makes gas prices for residential consumers relatively high compared with the market price. Introducing regulations that control the rate of return for gas companies may help bring gas prices down and subsequently increase fuel switching.

Most of Chile's gas network is located in the north and central regions because of higher population density as well as high gas demand. However, lack of gas infrastructure in the southern region (which has lower population density) curbed overall gas demand in Chile. The growth in demand since the construction of new LNG import terminals shows that regional integration actually helps economies increase gas uptake, provided that the exporter is reliable.

Chile does not have a carbon tax system in place, yet. The Chilean government plans to introduce a carbon tax of USD$ 5 per ton of CO_2 emitted from thermal power stations with installed capacity equal to or larger than 50 megawatts by 2017. The increase in the relative price of electricity will promote the use of cleaner fuels, encouraging energy producers to implement energy efficiency measures and embrace low-carbon technologies.

Conclusion

The increase in natural gas consumption in Chile, post 2009 when pipeline imports stopped, was a consequence of energy security policies rather than the effect of lower costs or a boom in the availability of natural gas. Natural gas used in electricity generation represented about 10% of primary energy used in power sector for the last five years. In "Energy 2050", the government recognised gas as one of the energy sources that needs to be maintained in the future energy mix. Although renewable energy is expected to be the driver of future energy needs, natural gas is expected to continue to grow as a complement to the whole energy system.

Although there are challenges in expanding gas usage in the residential sector, Chile is moving in the right direction, particularly in improving market oversight. However, since gas is competing against other fuels such as LPG, which has a well-established network, and firewood, that has high penetration in regional Chile, expanding usage might be challenging despite the benefits to the consumer.

CHAPTER 2

CASE STUDY: CHINA

Introduction

China is one of the world's most important economies. It is located in north-east Asia and is bordered by the East China Sea, the Yellow Sea and the South China Sea. Its population of 1.4 billion is approximately one-fifth of the world's population. China has a land area of approximately 9.6 million square kilometres (km^2) with diverse landscapes, which consist of mountains, plateaus, plains, deserts and river basins. Its total maritime area is 4.7 million km^2 and the length of its coastline is 32 000 km (NBS, 2016).

After reforming and opening up its economy in 1978, China entered a new period of high-speed growth. Its entry into the World Trade Organisation (WTO) in 2001 contributed further to its prosperity in the first decade of the twenty-first century. In 2015, China's gross domestic product (GDP) was 19814 billion (USD purchasing power parity [PPP]), with the primary, secondary and tertiary industries accounting for 9%, 40.5% and 50.5% respectively (World Bank, 2016; NBS, 2016).

China's energy consumption grew by 1.5% in 2015. This was less than one-third of the 10-year average growth rate of 5.3% and the slowest annual rate of growth since 1998 (BP, 2016). However, China remained the world's largest energy consumer and accounted for 23% of global energy consumption and 34% of net global energy growth in 2015 (BP, 2016).

China is rich in energy resources, particularly coal. According to BP statistics published in June 2016, China had recoverable coal reserves of approximately 114.5 billion tonnes, proven oil reserves of 18.5 billion barrels and proven natural gas reserves of 3.7 Tcm (BP, 2016) (Table 3.1). In addition, China has 400 gigawatts (GW) of economic hydropower potential, more than any other economy. Coal and oil resources have been utilised more extensively than natural gas and hydro for power generation and industrial development.

The reserves per capita of coal, oil and gas are all well below the worldwide average levels. The limitations of its energy reserves per capita force China to conserve its resources. From 2000 to 2014, the compound annual growth rate (CAGR) of final energy demand was 8.7% and the CAGR of GDP was 9.8% (EGEDA, 2016).

Table 3.1 • China key data and economic profile, 2014

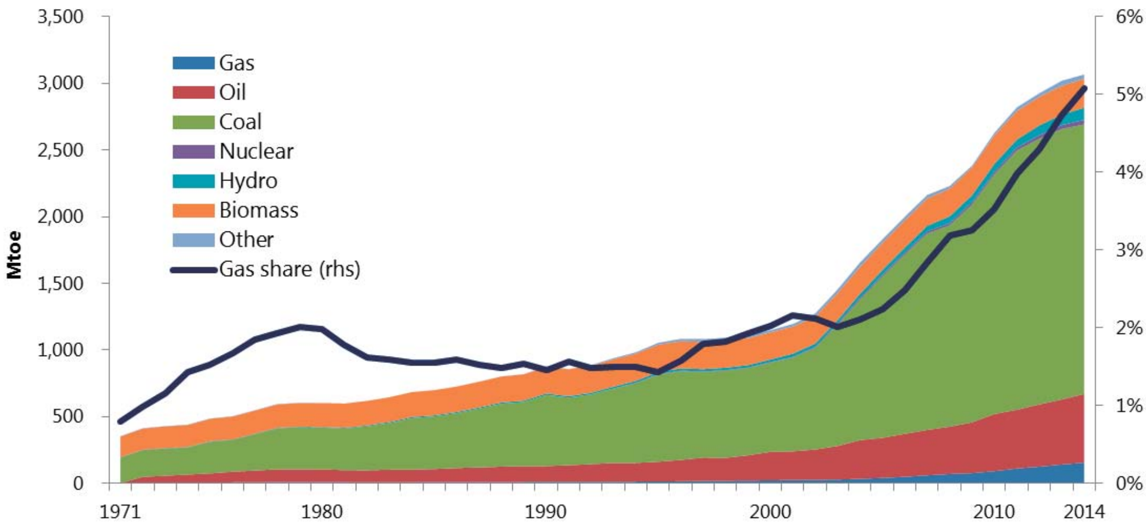
Key data[a, b]		Energy reserves[c]	
Area (million km^2)	9.6	Oil (billion barrels)	19
Population (million)	1 364	Gas (trillion cubic metres)	3.7
GDP (2010 USD billion PPP)	16 841	Coal (billion tonnes)	115
GDP (2010 USD PPP per capita)	12 344	Uranium (kilotonnes U)	114 500

Sources: a. EGEDA (2016); b. NBS (2016); c. BP (2016).

Natural gas in 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 in 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% from a lowly 1.5% in 1990. (Figure 3.1)

Figure 3.1 • Change in primary energy supply in China, 1971-2014



Source: IEA, (2016a)

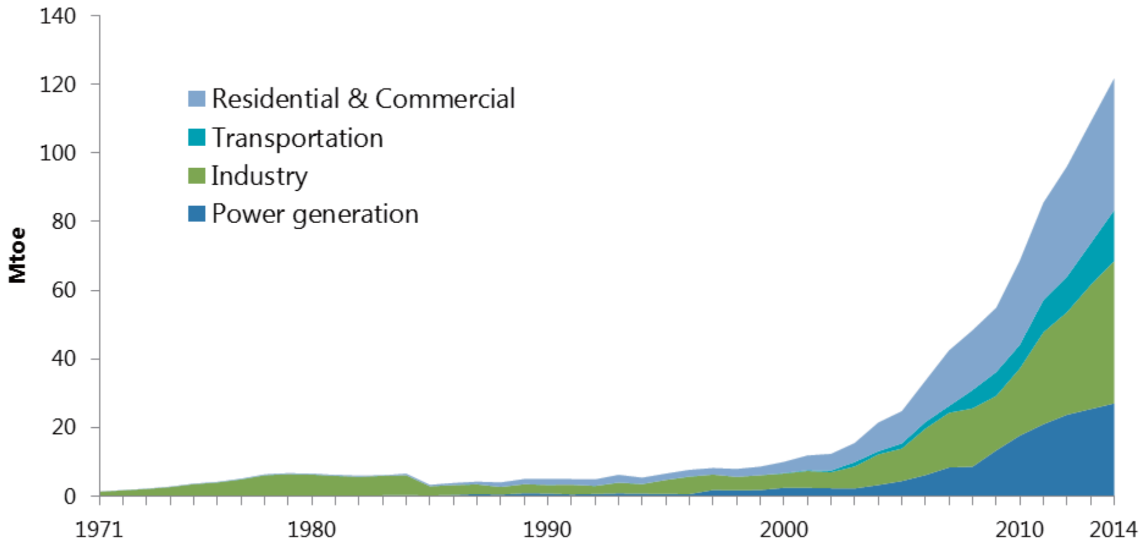
Securing energy supply is one of China's energy strategies. Thus, China has been striving to encourage the transportation of gas from west China and economies around China, such as Russia and the Central Asian economies where there are significant resources, to east China where demand is at its strongest and where an energy shortage is apparent.

The state of natural gas use

Energy consumption continues to increase as the economy grows and the population increases. In 2010, China became the world's largest energy-consuming economy, accounting for approximately 21% of global energy consumption. In the 1990s, the use of LPG rapidly advanced with the cancellation of import restrictions. Consumption rapidly increased with the recommendation of natural gas for the first time in the 9th Five Year Plan (1996 to 2000), which resulted in increased production of domestic natural gas and progress on the construction of the first major pipeline. In addition to expanding domestic production to date, pipelines and LNG imports are proceeding to ensure supply in preparation for increasing domestic demand in the future.

Natural gas was originally used primarily for industrial purposes in China, but in recent years there is an increasing trend for power generation and residential use. However, in terms of the primary energy supply, coal accounts for about 66%, while natural gas accounts for only about 5% as of 2014 (IEA, 2016a) (Figure 3.2).

Figure 3.2 • Natural gas usage by sector in China (1971-2014)



Source: IEA (2016a)

Natural gas policies

Fundamental natural gas policy laid out in the five-year plans that set forth economic and social development (Table 3.2). 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 set out 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 3.2 • Natural gas in China's five-year plans

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

	pipelines • Promote reform project to transition from coal to natural gas as a measure to combat air pollution • Accelerate construction of natural gas peak load regulating power plants

Source: IEEJ (2017)

In 2007, the National Development and Reform Commission established a "natural gas usage policy" to promote the effective use of natural gas. The policy divides natural gas use into four categories – city gas, industrial use, power generation and natural gas chemical industries, and classifies natural gas usage as "priority," "permitted," "restricted" and "prohibited".[2] In the 2012 policy revision, gas consumption in industry, residential and transportation (particularly for automobiles and ships) was promoted from "permitted" to "priority."

Efforts to promote the use of natural gas

In an effort to promote future use, the Chinese government is implementing measures such as revising the price system, reforming the domestic gas market, improving infrastructure and use in the transportation sector, and restricting its consumption in certain sectors.

Revising the price system

The Chinese central government sets 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.

In June 2013, the National Development and Reform Committee issued its *Notice on the Adjustment of Natural Gas Prices* and adopted the market net-back method to set the wholesale price (city-gate price) of natural gas for other than residential use (NDRC, 2013). To accelerate the establishment of a new natural gas pricing mechanism and at the same time reduce the impacts on existing downstream users, a price adjustment scheme will be launched. Under this pricing mechanism, the gas pricing components are divided into two groups – stock gas which is equivalent to gas demand recorded in the previous year and incremental gas which is equivalent to new gas demand for that particular year. The price of stock gas shall be adjusted gradually until it reaches market price (full adjustment) at the end of the "12th Five-Year Plan" period while the incremental gas price shall be adjusted once by benchmarking the price with alternative fuels such as fuel oil and LPG (weighted at 60% and 40%). By April 2015, existing gas prices were integrated with imported heavy oil and imported LPG prices. Based on this system, the government is gradually reducing wholesale prices, and reflecting the declining international petroleum product market price in recent years. In November 2015, it decided to lower the city-gate price by about 30% and to switch from an upper price to a base price, and allow up to a 20% variation from the base price (Table 3.3).

[2] Use of gas as a feedstock for gas-based chemicals such as ammonia is restricted, and its use for power generation fuel in coal producing provinces such as Inner Mongolia is prohibited.

Table 3.3 • Overview of natural gas price reforms in China (2011-November 2015)

	Description
December 2011	• Trial market linking non-residential wholesale prices in the south (Guangdong and Guangxi provinces). • Oil price linkage: 2010 import price of alternative fuel (heavy oil, LPG) in Shanghai. • Discount rate (10%): Set to 10% to promote transition from petroleum products to natural gas.
July 2013	• Review nationwide non-consumer wholesale price, and apply two-stage pricing of previous year's consumption and increase.
September 2014	• Review of non-consumer wholesale prices nationwide, which resulted in: 1) The price of the previous year's consumption increased by 18% on average; and 2) The price of the increased portion was unchanged.
April 2015	• Review non-residential wholesale price, and integrate price of previous year's consumption and increase, which resulted in: 1) The previous year's daily price increased by 20% on average; and 2) The price of the increased portion fell by an average of 15%. • Free trial of direct delivery price (power generation excluding chemical fertilizer, large industry).
November 2015	• Review of non-consumer wholesale price, which resulted in: 1) 30% price reduction; and 2) Changed the city-gate price from an upper limit price to a base price, allowing up to a 20% variation from the base price).

Source: JOGMEC (2016)

Institutional reform to open the natural gas market

China is making progress in its policy of opening its natural gas market. 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.

At the Third Plenary Session of the 18th Central Committee of the Communist Party of China in November 2013, the three major policies of a mixed ownership economy, liberalisation of resource allocation and liberalisation of resource prices were announced. Also set forth were policies relating to the building of infrastructure in sectors such as electricity, railways, communications, and oil and natural gas; the separation from management; and a policy to advance the market price of each sector. In February 2014, the National Energy Administration announced a notice on the "fair opening and supervisory control of oil and natural gas pipeline networks" for strengthening domestic supply through the effective use of domestic oil and natural gas infrastructure. The notice states that companies operating oil and natural gas pipelines should fairly open up their pipelines to third parties (registered companies in China) if the facilities have surplus capacity, and provide pipeline services (transportation, storage, gasification, liquefaction, compression) (NEA, 2014). In addition, the National Development and Reform Commission announced the *Construction of Natural Gas Infrastructure and Operations Management Law* that gave permission for third party access to LNG terminals (Table 3.4).

Table 3.4 • Third party access to LNG terminals in China (2014-2015)

Receiving terminal	Investing company	User	Receiving capacity
Rudong, Jiangsu province	PetroChina	• Shenergy • ENN • Pacific Oil & Gas	3.5 Mt/year
Tangshan, Hebei province	PetroChina	• Beijing Gas	3.5 Mt/year
Dalian, Liaoning province	PetroChina	• Guanghui Energy	3.0 Mt/year

Source: IEEJ (2017)

Following that, in August 2015, the Communist Party Central Committee and the State Council jointly announced guidelines to deepen the reform of state-owned enterprises. Even in the natural gas market, the aim of the guidelines is to increase the number of businesses and investment funds and encourage the introduction of market mechanisms by promoting an open market (Table 3.5). In August 2016, the National Development and Reform Committee announced a natural gas pipeline transportation price control law and natural gas pipeline transportation cost investigation law based on the State Council of the Communist Party of China's Reform Mechanism, with the aim of reducing pipeline transportation costs, improving transparency, promoting natural gas development and use, and third-party access (NDRC, 2016). The laws stipulate a detailed description of transportation margins and a breakdown of costs, such as personnel expenses.

Following this series of reforms, the monopoly held by three major oil companies China National Offshore Oil Corporation (CNOOC), China National Petroleum Corporation (CNPC) and Sinopec over LNG import terminals collapsed, and Chinese private companies, including non-state-owned oil companies, are entering the market.

Table 3.5 • State-owned enterprise reform policy in China

Oil and gas items determined in the 3rd Plenary Session of the 18th Central Committee of the Communist Party of China		The National Development and Reform Commission, and National Energy Administration	State-owned enterprise
1) Mixed ownership economy			Sinopec: Accept non-state-owned investment in the sale of petroleum products PetroChina: Partner with local companies in shale development
2) Marketisation of resource allocation	Separation of maintenance and operation divisions of oil and gas pipelines	Trial run of pipeline opening management method (February 2014)	
3) Marketisation of resource prices	Price of oil and natural gas	Non-residential natural gas wholesale price reform (November 2015 and others)	

Source: JOGMEC (2014)

Coal consumption restraint policy

In August 2014, the Beijing Municipal Environmental Protection Bureau announced that it would prohibit the sale and use of coal in the six districts of Dongcheng, Xicheng, Chaoyang, Haidian, Fengtai and Shijingshan by 2020 (RIM, 2014). According to the city's environmental protection targets set in the 13th Five-Year Plan, coal-fired boilers will be banned in the city by the end of 2020. Coal as a fuel for heating has virtually been eliminated in the Pinggu district while all private service businesses using coal energy need to convert to cleaner energy.

In February 2016, to resolve the surplus capacity problem caused by declining coal demand due to economic slowdown and lower consumption as a result of environmental measures, the National Energy Administration announced a detailed reform plan that included coal mine closures and coal production adjustments. Specifically, in 2016, the Chinese government decided to close 1,000 or more small and aged coal mines, 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. In April 2016, the State Council of China established 276 regulations with the aim of reducing the production and consumption of coal by decreasing the number of coal mine operating days from 330 days a year to 276 days or less.

In addition to reducing production capacity, the Chinese government has also developed policies on the usage of coal, and the 13th Five-Year Plan (2016-2020) calls for the "clean, highly-efficient use of coal" in the mining industry, and promotes energy-saving by retrofitting coal-fired power generation plants and lowering consumption.

In addition to this, China is also promoting environmental pollution control. According to China's commitment under the 2015 United Nations Framework Convention on Climate Change, CO_2 emissions per GDP expected to be reduced 60%-65% by 2030 compared with 2005 levels. At the same time, China will raise the share of non-fossil fuels in primary energy to about 20% by 2030. On top of this, the National Energy Administration issued a *Notice on the Promotion of Domestic Coal-Fired Power Generation Development* in March 2016. It provided targets to ban new building of coal power plants when there is surplus power supply and pushed for areas with electric supply shortage to import power supply from other areas with power surplus, to build renewable power plants and to control power demand through energy conservation. Based on these measures, the notice aims to reduce new builds of coal power plants (NEA, 2016).

Construction of infrastructure

To prepare for further expansion of natural gas demand in the future and to ensure a stable supply, China will develop infrastructure facilities such as LNG receiving terminals, natural gas pipelines and natural gas underground storage, in parallel with expanding natural gas production. The arrival of LNG carriers from Australia's North West Shelf project at CNOOC's Shenzhen terminal in Guangdong province in 2006 marked the beginning of China's LNG market. LNG imports have continued to increase consistently, but were sluggish in 2015 due to the slowdown in growth of the Chinese economy, and other seasonal factors. However, in the first half of 2016, demand recovered as the cuts in wholesale prices and the shift from coal to natural gas accelerated.

Against the backdrop of increased demand, major state-owned oil companies such as CNOOC, CNPC and Sinopec were given exclusive rights to import LNG to China. However, with government reforms, new terminals operated by non-state-owned oil companies have been allowed to enter the market (Table 3.6).

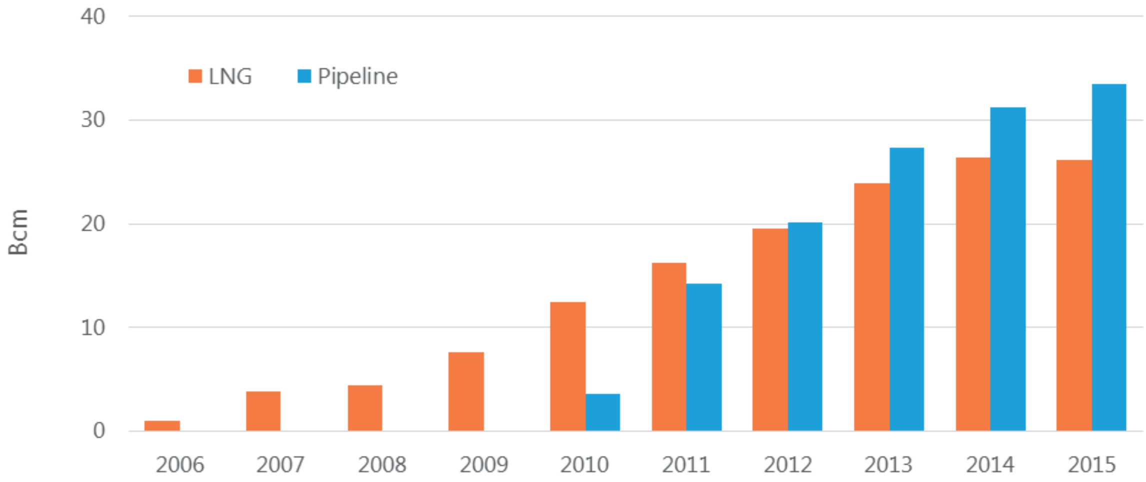
Table 3.6 • Main LNG receiving terminals of non-state-owned oil companies in China

Participating company	Construction location	Receiving capacity (Mt/year)	Startup	Remarks
Jovo	Guangdong province	1	2013	First private foreign LNG imports
Guanghui Energy	Nantong, Jiangsu province	0.6	2018 (scheduled)	Import and sale of LNG in cooperation with Shell
ENN	Zhoushan, Zhejiang province	3	2018 (scheduled)	First LNG bunkering terminal in China
Huandian	Chengmai, Hainan province	3	2020 (scheduled)	Three tanks to be built in first stage
Huandian	Jiangmen, Guangdong province	6	2020 (scheduled)	Investment agreement signed with Taishan government
Huandian	Yueyang, Hunan province	0.5	2020 (scheduled)	Hunan river LNG strategic stockpile center

Source: East & West Report, October 6, 2016

Regarding pipeline infrastructure, according to the plan announced by the National Energy Administration in 2012, a new 44 000km domestic trunk line pipeline was expected to be constructed between 2011 and 2015. This new pipeline will increase transport capacity to 150 Bcm. The 13th Five Year Plan announced in 2016 focused on developing the natural gas transport routes of the West-East Gas Pipeline, Shaanxi-Beijing Pipeline and Sichuan-Shanghai Pipeline. Natural gas produced in western China was sent to the east coast through the West-East Gas Pipeline. The third West-East Gas Pipeline started its operation in December 2016 with the fourth West-East Gas Pipeline being planned. Natural gas imports by pipeline started from 2010, but in just over a year they equalled the amounts of LNG imports (Figure 3.3).

Figure 3.3 • Natural gas import volume in China, 2006-15



Source: Cedigaz (2016).

As a seasonal adjustment and backup, China maintains underground natural gas storage using depleted gas fields and rock salt domes. Maintenance of underground storage is primarily carried out by PetroChina. As of the end of 2010, the storage capacity remained at about 2% (about 2.1 Bcm) of consumption as a backup for the Shaanxi-Beijing Pipeline that carries gas for Beijing, and reached about 8% (15.9 Bcm) of consumption at the end of 2013 (JOGMEC, 2014). By expanding storage capacity, it is expected that China can expand supply gas in the winter when demand increases and contribute to the promotion of the use of gas at reasonable prices.

Gas use in the transportation sector

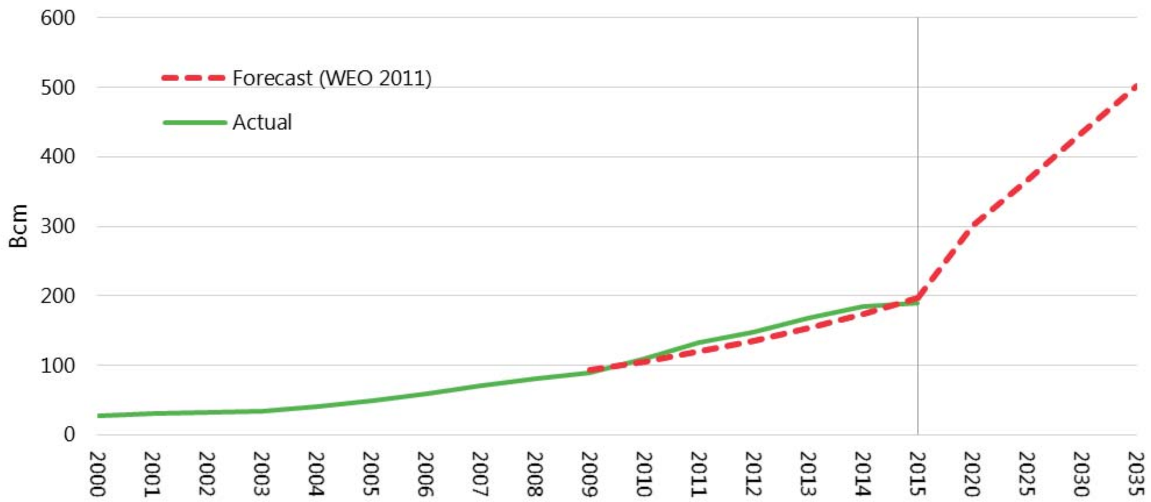
Under the gas policy announced by the National Development and Reform Commission in 2012, the use of natural gas as a transportation fuel was set as a priority for the government, particularly in automobiles (such as mixed-fuel vehicles with dual diesel and LNG), public buses, taxis, delivery vehicles, long-distance buses, cleaning vehicles, freight cars, and domestic marine vessels.

As of 2015, there were more than 2.5 million NGVs in China (including modified and specialised cars), supported by more than 4,000 compressed natural gas (CNG) and LNG stations or combined gas and oil stations. The government has been instrumental in the spread of CNG and LNG vehicles in China, where subsidies for vehicle modifications, the construction of gas filling stations, and the purchase of NGVs are among government incentives. Furthermore, CNG and LNG are exempted from value-added taxes (natural gas business is taxed at 13% while oil and other business are taxed at 17%).

Actual and forecast natural gas demand

Natural gas demand in China was, according to the IEA's 2011 World Energy Outlook estimated to be about 197 Bcm in 2015. The actual figure was slightly lower at 190 Bcm (Figure 3.4). Chinese demand for natural gas is expected to increase in the power generation, residential and industrial sectors. In addition to the expansion from economic growth, reform of the natural gas wholesale price (city-gate price) has gradually progressed from 2011, and with the government policy giving priority to natural gas use in industrial, residential, automotive and marine, gas consumption is expected to grow in the future.

Figure 3.4 • Gas demand forecast as of FY 2010 and actual demand in China, 2000-35



Source: IEA (2011) and Cedigaz (2016)
Note: Since IEA reports do not provide yearly data in their publication, this study used the CAGR derived from the forecast demand to determine 2009-2015 data.

Issues for the increased use of natural gas

Transparent and timely pricing

To promote the use of natural gas in China, it is necessary to improve price competitiveness against other fuels such as coal and LPG. The Chinese government currently controls the price of natural gas. Until now, the government has adjusted the price to reverse the negative spread between imported gas and crude oil prices. However, as there is no transparent price index linked with the world market, it is difficult for businesses to predict future prices. As for gas prices for non-residential use, although changes such as shifting to the net-back system and allowing up to a 20% variation from the base price have been made, the price of natural gas is still rigid compared with petroleum products that can fluctuate every 10 working days.

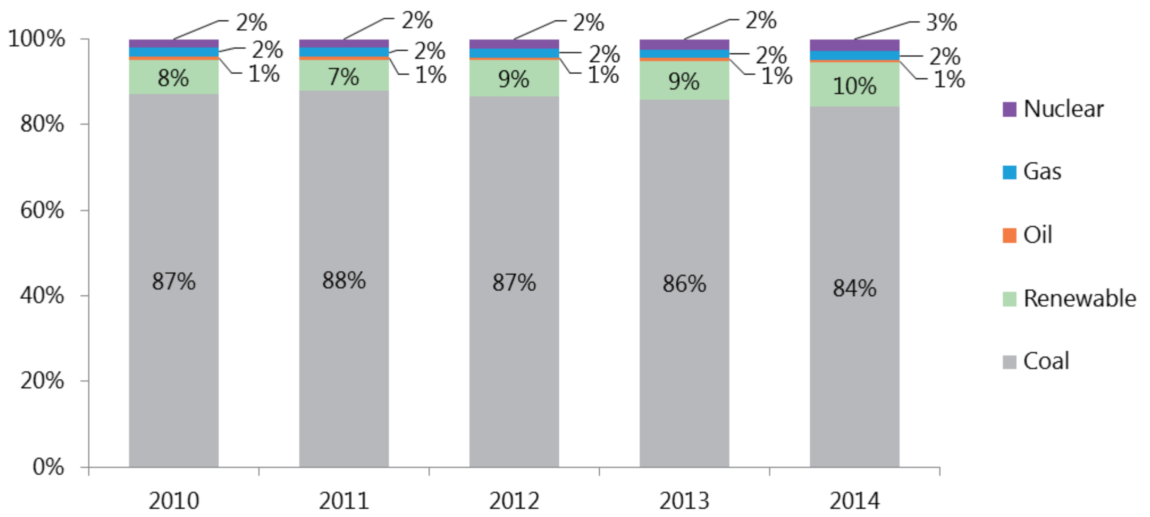
The Chinese government has controlled the city-gate price of natural gas to promote fuel transition from oil to gas. However, price controls are disadvantageous in terms of profitability to businesses that enter high-cost shale development and production. Price controls also become a hindrance to LNG 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.

From this standpoint, the Chinese government established a natural gas exchange (Shanghai Petroleum and Natural Gas Exchange (SHPGX)) with 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. However, the volume of transactions from January to August 2016 was too low (1.88 Bcm for pipeline gas and 220,000 tons for LNG) to established a gas price index. Therefore, the number of participants in the market needs to increase in order to establish a true price index.

Expansion of gas use in the power generation sector

Due to the rapid increase in electricity demand from economic and population growth, construction of large-scale power plants has grown rapidly since 2002, with annual electricity consumption in 2014 reaching 5 560 TWh, China's electricity generators are the number one energy consumer in the world. However, as shown in Figure 3.5, coal accounts for 80% or more of the power supply as of 2014, while the proportion of natural gas is only about 2%. China has abundant coal resources and has been a major consumer of coal to date, but air pollution has become serious in recent years. To cope with the increasing demand for energy in the future, China is trying to cut coal consumption and free itself from its dependency.

Figure 3.5 • Power supply generation mix in China, 2010-14



Source: IEA (2016a)

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%. Specifically, it seeks to expand conventional hydropower generation to 340 GW, wind power to more than 210 GW, and solar power (solar PV and solar thermal) to 110 GW. The plan reaffirms the start of an additional 30 GW of nuclear power capacity between 2016 and 2020, as well as expansion of the generation capacity to 58 GW by 2020.

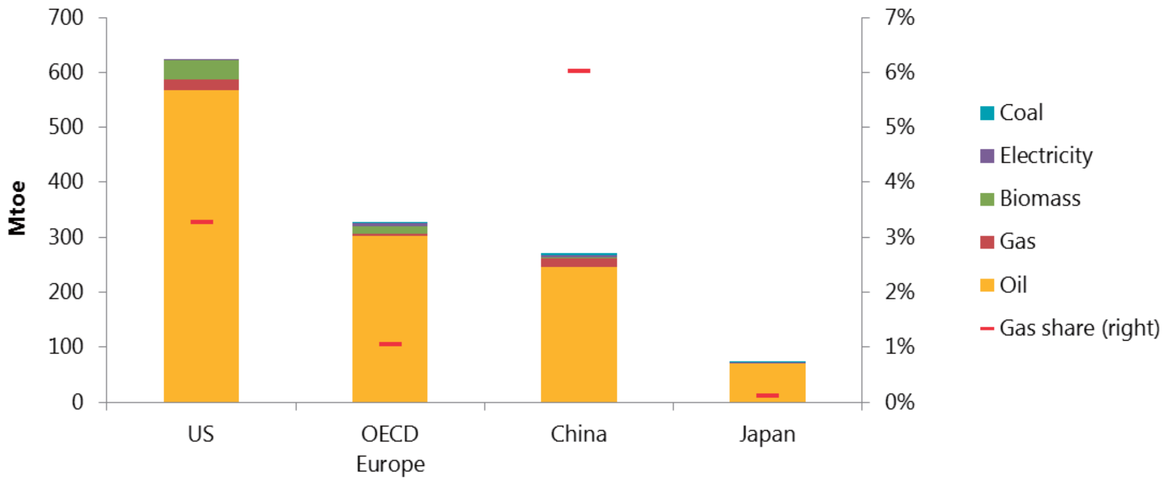
Even if China promotes policies to curb coal consumption, the expansion of natural gas in the power sector will be limited because of the competition from other fuels such as renewable energy and nuclear power. For this reason, it is necessary to pursue policies that prioritise the use of natural gas. At the same time, to become competitive with other energies such as coal and LPG, the establishment of a mechanism is needed that leads to high transparency and reasonable gas prices, as described in the *Revising the Price System* section.

In addition, promoting the use of natural gas in the power generation sector may lead to higher unemployment in the coal industry, meaning that measures to support those workers are also required. According to information released by the Ministry of Human Resources and Social Security in July 2016, promoting reforms to eliminate excess production of steel and coal was projected to cause 800,000 people to lose their jobs in 2016 alone (Sankei Shimbun, 2016).

Expansion of use in the transportation sector

As discussed in the *Gas Use in the Transportation Sector* Section, 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. However, as Figure 3.6 illustrates, the proportion of natural gas consumption in the transportation sector of China is relatively high compared with Europe, the United States and Japan, it remained at about 6% of consumption in 2014.

Figure 3.6 • Transportation energy consumption and gas share in China, 2014



Source: IEA (2016a)

The Chinese government has designated electric vehicles (EVs), plug-in hybrid vehicles (PHVs), and fuel cell powered vehicles (FCVs) as "new energy vehicles," and is working to popularise them. The government has offered subsidies to consumers when they purchase new energy vehicles. In August 2014, the Ministry of Finance, the State Administration of Taxation and the Ministry of Industry and Information Technology announced the *Exemption of Vehicle Purchase Tax on New Energy Vehicles* which gave preferential tax treatment to new energy vehicles. In April 2015, the Ministry of Finance, Ministry of Science and Technology, Ministry of Industry and Information Technology and the National Development and Reform Commission jointly announced the circular on the *Financial Support Policy on Promotion and Application of New Energy Vehicles* from 2016 to 2020. Not stopping just at financial support, the government further promotes the usage of electric vehicles through the 13th Five Year Plan for Electric Power Development. Plans include development of an infrastructure system for new energy vehicles such as charging stations, charging poles and other infrastructure in order to meet the demand for more than 5 million electric vehicles nationwide by 2020. This policy support for new energy vehicles poses a challenge for the spread of LNG and CNG vehicles in China.

Besides land transportation, China plans to expand natural gas consumption for river and lake transport vessels. In August 2015, the Ministry of Transport announced an action plan (2015-2020) for the prevention of environmental pollution by ships and ports. At the same time, the Ministry of Environmental Protection announced an emission standard for domestic shipping vessels by the end of 2015 and natural gas retrofitting standards for ships to adopt by the end of 2020, as well as conditions for non-compliant retrofitting and decommissioning of vessels. Even with these policies, it is necessary to strengthen maritime facilities, such as building port infrastructure that can supply LNG fuel to ships.

The construction of coastal ships and tugboats powered by LNG is a recent trend in China, and in 2014, the Ministry of Transport designated the Jiangsu Grand Canal region, which links Beijing to Hangzhou, Zhejiang province, as a model LNG water transportation district.

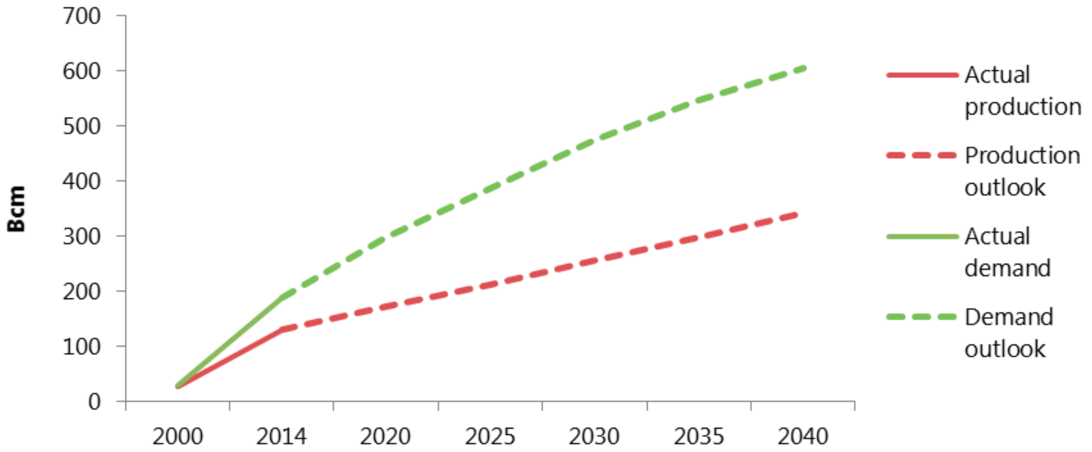
Increase of domestic gas production focusing on shale gas

As demand for natural gas in China increases, the government plans to expand production. To meet energy security and environmental pollution goals, China needs to ensure that it has stable supply capacity to meet the demand. In March 2012, the *Shale Gas Development* Plan (2012-2015) was announced by the National Energy Administration with a production goal of 6.5 Bcm and a total gas production target of 145 Bcm by 2015. With this target, the Chinese government has been providing subsidies aimed at promoting shale gas development since 2012, and both PetroChina and Sinopec have been on the receiving end of these subsidies.

However, the actual amount of shale gas produced reached only about 4.5 Bcm while total domestic natural gas production just managed to reach 127.3 Bcm in 2015 (Figure 3.7). This is because Sichuan province, considered to be one of the main shale gas producing areas, is very difficult to develop owing to its complicated geological structure and a gas reservoir layer that is far deeper than in the United States and other economies.

Up until now, only China's state-owned enterprises have been able to participate in exploration and development projects, but based on the mixed ownership development policy in the state-owned enterprise reform promoted by the government, private companies can participate in exploration and development projects, provided that they meet certain conditions. In July 2015, in bidding for the Xinjiang oil and natural gas exploration region conducted by the Ministry of Land and Resources, oil and gas exploration was opened for the first time to Chinese companies other than state-owned oil companies (Sinopec, CNPC, CNOOC, Shaanxi Yanchang Petroleum Group). Fourteen companies participated in the bidding, with Beijing Energy Investment Holding bidding for three of the five blocks and Shandong Polymer Bio-chemicals being awarded the first block (1 block went unsold). In the upstream sector, which is monopolised by state-owned enterprises, the government is actively promoting domestic and foreign investment by promoting policies that encourage entry of new businesses. These policies are expected to reduce production and development costs of domestic natural gas, which subsequently helps to secure a stable supply volume.

Figure 3.7 • Change in natural gas production and demand in China, 2000-40



Source: IEA (2016b)

Conclusion

China has been the fastest growing natural gas market in Asia over the last decade. With a low share of gas in the total primary energy supply (5%), it has a significant potential for future demand growth. The past expansion of natural gas demand was mainly thanks to the rise of domestic natural gas production and rapid development of a nation-wide pipeline network. State-owned oil companies in China are expected to continue development of wellhead production and pipeline networks, and natural gas demand is likely to continue to grow in China.

Government policy, particularly environment policy, also favours natural gas demand. In order to reduce pollution caused by excessive coal consumption, the Chinese government is trying to control coal consumption, and natural gas, is a major substitute of coal in power sector. The Chinese government has set the targeted share of natural gas at 10% as of 2020. Such target setting will facilitate mobilisation of domestic financial, human, and technical resources to further enhance natural gas consumption in the economy.

CHAPTER 4

CASE STUDY: INDONESIA

Introduction

Indonesia, located south-east of mainland South-East Asia, between the Pacific Ocean and the Indian Ocean, is the world's largest archipelagic state. Indonesia's territory encompasses 17 504 islands around the equator over an area of 7.9 million square kilometres (km^2). This constitutes Indonesia's exclusive economic zone. Indonesia's total land area (25% of its territory) is about 1.9 million square kilometres. The population was 254.5 million in 2014 (Table 4.1).

Indonesia had a gross domestic product (GDP) of around USD 2 500.9 billion and a per capita GDP of USD 9 828 in 2014 (2010 USD purchasing power parity [PPP]). Excluding the oil and gas sector, manufacturing industries accounted for the largest component of GDP in 2013 (21.6%), followed by agriculture, forestry and fishing with a combined share of about 13.7%. The main exports are mineral fuels, lubricants and related materials, which together account for about 29% of total export value, followed by manufactured goods at 12.8%. In 2014, Indonesia attained economic growth of 5.0%, slightly lower than the previous year (BPS, 2016).

Domestic oil, gas and coal reserves have played an important role in Indonesia's economy as sources of energy, industrial raw materials and foreign currency. In 2014, oil and gas exports contributed 11% and coal exports contributed 5% of Indonesia's total exports. Overall, tax and non-tax revenue from oil, gas and minerals including coal accounted for 19% of the Indonesian Government's budget in 2014 (ESDM, 2015a). Indonesia's proven fossil energy reserves at the end of 2014 consisted of 7.4 billion barrels of oil, 4.3 trillion cubic metres of natural gas and 32 billion tonnes of coal (ESDM, 2015b).

Table 4.1 • Indonesia key data and economic profile, 2014

Key data[a]		Energy reserves[b,c]	
Area (million km^2)	1.9	Oil (billion barrels)	7.4
Population (million)	254	Gas (trillion cubic metres)	4.3
GDP (2010 USD billion PPP)	2 501	Coal (billion tonnes)	32
GDP (2010 USD PPP per capita)	9 828	Uranium (kilotonnes U)	6.3

Sources: a. EGEDA (2016), b. ESDM (2015) and c. NEA (2014).

In 2014, Indonesia's total primary energy supply (TPES) was 227 117 Ktoe, consisting of oil (38%), coal (20%), natural gas (16%), and others (mainly hydropower, geothermal, and biomass) (27%). Indonesia is a net exporter of energy with crude oil, condensates, natural gas (mainly in the form of LNG), petroleum products and coal totalling 220 920 Ktoe in 2014. Total energy exports in 2014 increased by 13% from 2013 (193 983 Ktoe) (EGEDA, 2016).

Natural gas in Indonesia

Indonesia is a mature player in the natural gas industry and has been producing LNG since 1977. It was the world's largest LNG supplier for three decades before Qatar surpassed it in 2006. In 2015, Indonesia was the fifth-largest LNG supplier after Qatar, Australia, Malaysia and Nigeria (IGU, 2016) with total exports of 16.1 Mtpa. Despite historically being the largest gas producer in Southeast Asia, the economy is expected to soon become a net gas importer in the form of LNG.

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[3] 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 industry sector by far is the biggest user of gas with 13 115 Ktoe (75%) consumed in 2014 and is followed by the other economic sector with 4 086 ktoe (23%) and commercial, residential and transport with combined consumption of 247 Ktoe (1%) (EGEDA, 2016).

Policies, Regulatory Frameworks and Governance Structure

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). Among its tasks are to draft the KEN and endorse the National Energy Master Plan (Rencana Umum Energi Nasional, RUEN).

The KEN sets development priorities for energy resources, encouraging exploitation and use of renewables and coal, as well as optimising gas use while minimising oil use. The policy identifies nuclear as the last energy option, after carefully considering the safety factor. The KEN sets out the ambition to transform, by 2025 and 2050, the primary energy supply mix with shares 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.

To encourage the use of domestic resources to meet Indonesia's energy needs, the government uses policy instruments such as energy pricing, subsidies and incentives, particularly for renewables. It also supports research and development to help commercialise specific energy technologies.

As for regulating oil and gas activities, the government introduced Law No. 22 dated 23 November 2001 (PwC, 2016). The objectives (Article 3) are to:

[3] 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).

- Guarantee effective, efficient, highly competitive and sustainable exploration and exploitation;
- Assure accountable processing, transport, storage and commercial businesses through fair and transparent business competition;
- Guarantee the efficient and effective supply of oil and gas as a source of energy to meet domestic needs;
- Promote capacity building;
- Increase state income; and
- Enhance public welfare and prosperity equitably, while maintaining the conservation of the environment.

In order to stimulate investment and improve upstream sector regulation, Indonesia introduced the fifth generation Production Sharing Contracts (PSCs) in 2008. The key differences between later generation PSCs and earlier generations are as follows:

- Some flexibility in the production-sharing percentage offered;
- PSCs now provide for a domestic market obligation for natural gas;
- The Upstream Oil and Gas Activity Agency or known as BP MIGAS is entitled to FTP (First Trenched Petroleum) of 10% of the petroleum production which is not shared with the contractor;
- The profit-sharing percentages which appear in the contract are determined on the assumption that the contractor is subject to a dividend tax on after-tax profits under Article 26 (4) of the Indonesian Income Tax Law, which is not reduced by any tax treaty;
- The certain pre-signing costs (e.g. for seismic purchases) may be cost recoverable;
- BP MIGAS must approve any changes to the direct or indirect control of the entity; and
- The transfer of the PSC participating interest to non-affiliates is only allowable with BP MIGAS's approval and where the contractor retains majority interest and operatorship, or three years after the signing of the PSC (PwC, 2016). Note that BP MIGAS role has since been handed over to Special Task Force for Upstream Oil and Natural Gas Business Activities or known as SKKMIGAS.

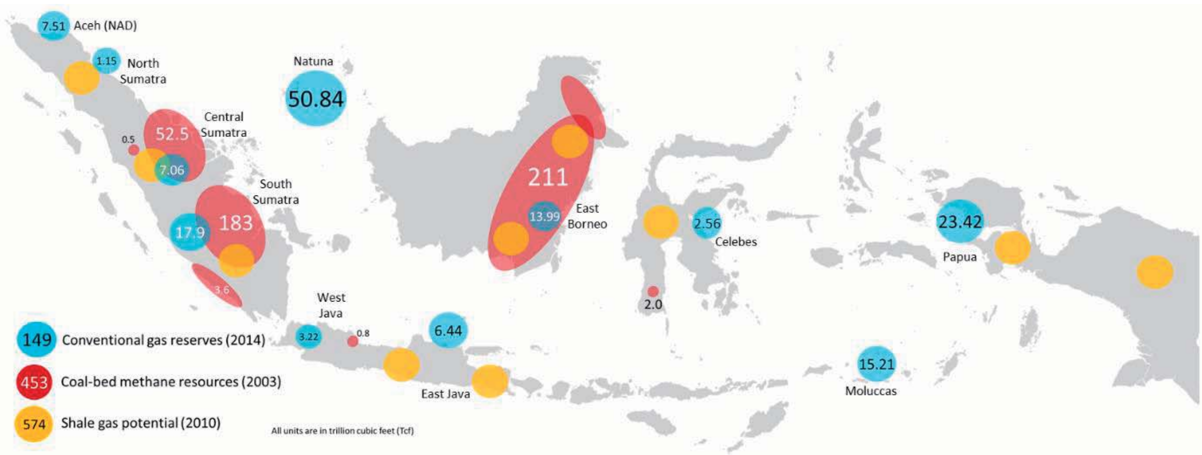
Indonesia revised the terms of the domestic market obligation in 2009. Under Government Regulation No. 55 of 2009, the contractor must allocate 25% of its oil or gas production to the domestic market. In relation to the development of new gas reserves, the government advises the contractor of the domestic gas supply requirement about a year prior to production. The contractor and prospective domestic buyers negotiate directly on gas price and terms of supply. However, if there is no domestic demand for gas or if an agreement between the contractor and prospective buyers is not reached, the contractor may sell its entire share to the international market.

Exploration and production

Indonesia has a diversity of geological basins which continue to offer sizeable oil and gas potential. Indonesia has 60 sedimentary basins including 36 in Western Indonesia that have already been thoroughly explored. Fourteen of these are producing oil and gas. In under-explored Eastern Indonesia, 39 tertiary and pre-tertiary basins show rich promise in hydrocarbons. About 75% of exploration and production is located in Western Indonesia. The four oil-producing regions are Sumatra, the Java Sea, East Kalimantan and Natuna. The main gas-producing regions are East Kalimantan, West Papua, South Sumatra, Sulawesi and Natuna (PwC, 2016).

At the end of 2014, the economy's proven natural gas reserves were estimated at 100 trillion cubic feet (Tcf) while potential reserves were estimated to be around 49 Tcf. The largest undeveloped gas reserves are located in the offshore East Natuna Block in the Riau Islands Province, which holds about 51 Tcf of conventional gas reserves (Figure 4.1).

Figure 4.1 • Indonesia gas reserves, 2014

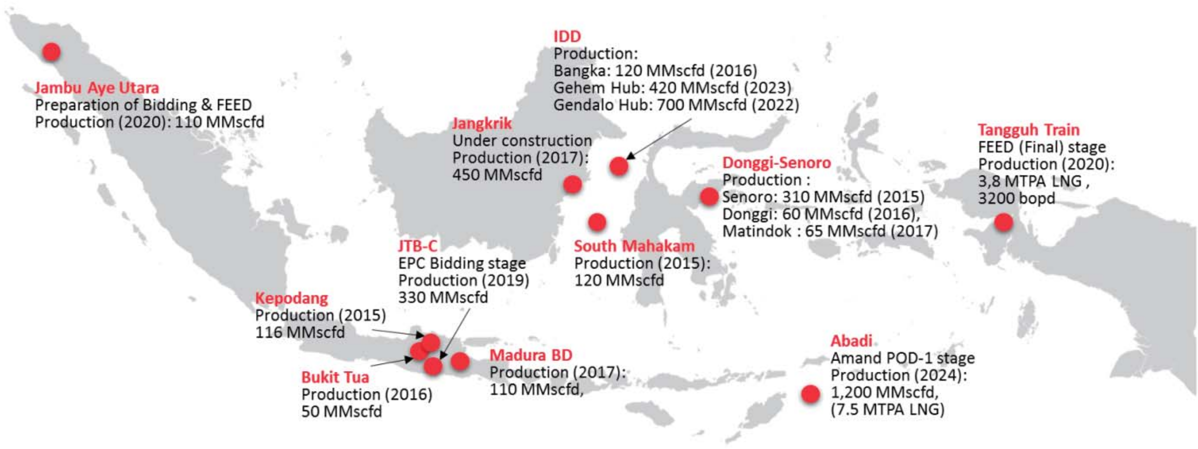


Source: Advance Resources International, Inc. (2003), Geology Agency (2010), ESDM (2015b) and APERC analysis.

Besides conventional gas, which is mainly produced offshore, Indonesia is estimated to hold more than 450 Tcf of coal-bed methane (CBM) resources and 574 Tcf of shale gas potential. Most of the CBM resources identified are located in East Borneo island (part of Kalimantan, Indonesia) and in Sumatera Island. Once commercial production comes online, the gas may be utilised by the Bontang LNG plants or be delivered to a CNG plant that might be stablished in South Kalimantan (Jakarta Globe, 2013).

Given that domestic gas demand is expected to increase rapidly in the future while production is not, the government, through SKK MIGAS has given the rights to energy companies to develop the economy's oil and gas in new fields through a number of major projects (SKKMIGAS, 2014) (Figure 4.2). Besides conventional gas exploration and production, Indonesia is embarking on unconventional gas production. The first unconventional gas production sharing contract (PSC) was signed in May 2013. Five PSCs have been signed since then (SKKMIGAS, 2014). However, the high costs of producing shale gas will hamper unconventional gas production, which in 2013, was expected to be at least 3 to 4 times higher than production in the United States (Jakarta Globe, 2013).

Figure 4.2 • Proposed, on-going and completed gas production projects in Indonesia, 2015-23



Sources: SKKMIGAS, 2014 and APERC analysis.

In 2014, there were 316 PSCs under the control of the upstream oil and gas implementing agency, SKKMIGAS. Of these PSCs, 81 were for oil and gas at the exploitation stage and 235 related to the exploration stage. Of the 235 PSCs, 180 PSCs were for conventional oil and gas, 55 were for shale gas and 8 were terminated and 41 were in the process of termination (SKKMIGAS, 2014).

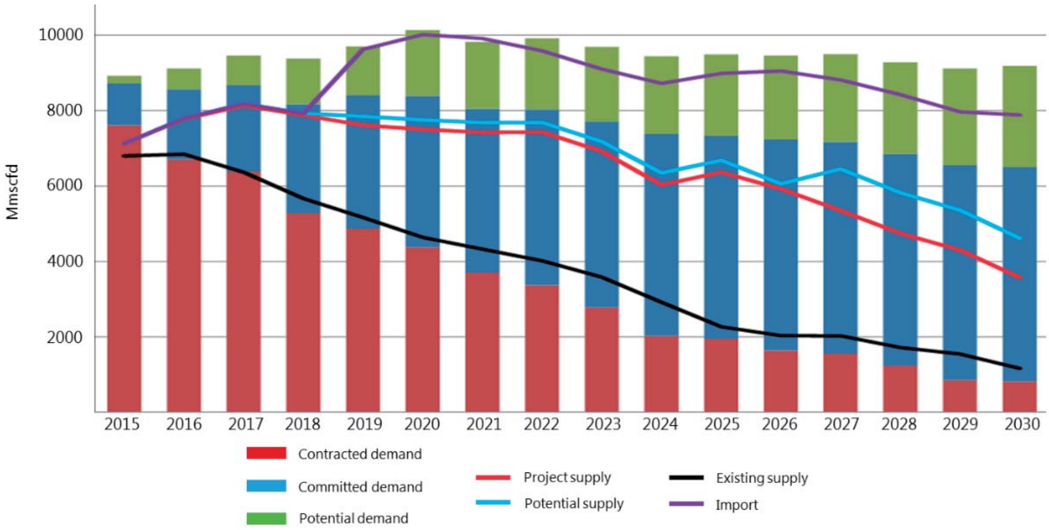
Gas demand and export

In early 2016, natural gas demand in the power sector increased sharply because of the Government Program: "35 GW". This program, started in 2015, targeted an additional 35 GW of power generation capacity across the economy by 2019. Out of 35 GW planned, more than one-third of the new capacity will be gas-fired generation. In order to meet new gas demand in the power sector, additional gas supply amounting to 1 100 million cubic feet a day (mmcf/d) will be needed (PLN, 2015). Due to sharp increases in gas demand, the government is considering importing gas, either as LNG or through pipelines.

Beside the power sector, gas demand for fertilizer and petrochemical plants is expected to increase in the future. Based on Presidential Instruction No. 2 of 2010, the Ministry of Industry Indonesia will coordinate and supervise government plans to revitalise the fertilizer making industry. Two new highly efficient fertilizer plants (PKT 5 and PUSRI IIB) started their operation in 2016 and another factory is expected to open in 2017. At the same time, a new petrochemical plant (Petrochemical Gersik) is expected to start operation in 2017. All these new plants will add to the gas supply challenges faced by Indonesia. In order to curb gas demand from these new plants, the government has imposed a higher efficiency standard to the factories. Gas demand for petrochemicals is expected to rise sharply in 2020 as a new plant located in the West Papua Province will begin operation (Kemenperin, 2017a).

According to Pertamina (a state-owned oil and gas company) and PGN (another state-owned gas company), there was a 600 mmcf/d gap between supply and demand in the industry sector in 2015. Industrial natural gas demand tied to contracts was around 1 600 mmcf/d while the total requirement was around 2 200 mmcf/d of natural gas. Besides the industry sector, gas demand in the transport and residential sectors is expected to increase in the future (Kemenperin, 2017b) (Figure 4.3).

Figure 4.3 • Future gas production, demand and import in Indonesia, 2015-30

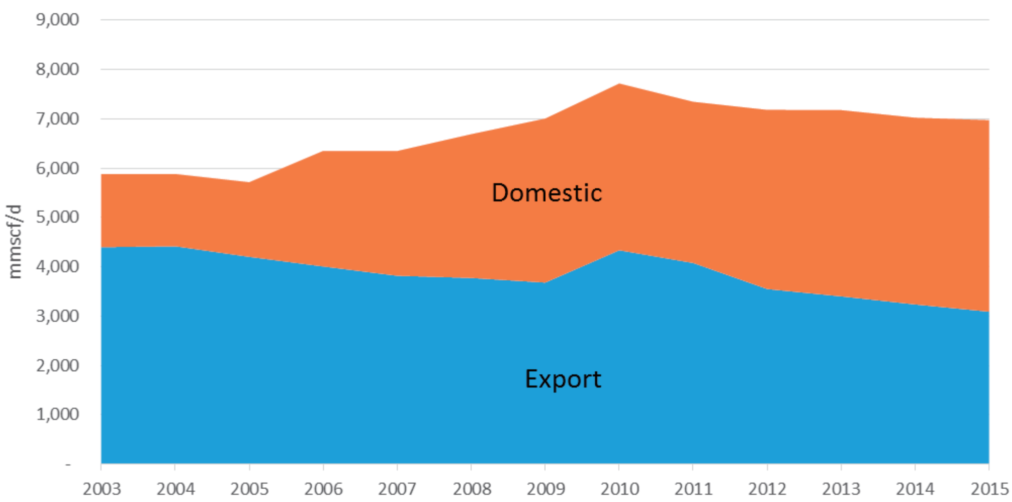


Source: ESDM, 2015c

In 2015, existing production was only able to supply 94% of contracted demand. This was because of decreases in existing production coupled with development delays of new fields. For the 2016-2022 period (medium-term), the growing demand by the industrial and electricity sectors is expected to add additional constraints to the supply side, which forced the government to consider gas and LNG import in the near future. The supply gap will widen in long term (2023-2030) as gas production from Natuna and Masela fields, which hold most of Indonesia's gas, will not be able to keep up to the demand growth.

As mentioned previously, Indonesia used to be the biggest LNG exporter in the world until overtaken by Qatar in 2006. LNG export reached its peak in 2010 at 31 Bcm, falling to 21 Bcm in 2015. At the same time, gas export through pipelines to Malaysia and Singapore increased from 5.8 Bcm in 2006 to 7.9 Bcm in 2015. Overall, gas export decreased by nearly a quarter from its peak of 40.9 Bcm in 2010 to 30.3 Bcm in 2015. Figure 4.4 shows the transformation of gas allocation, from mainly for export to domestic consumption.

Figure 4.4 • Indonesia natural gas export and domestic demand, 2003-15



Source: SKKMIGAS, 2015

Gas price structure

A gas price formula is normally stipulated in the contract between producers/suppliers and buyers. In general, there are two price categories in Indonesia which are:

- Gas price based on market rates. The price will be benchmarked against the cost of gas production from the field, which is normally tied with long-term contracts. Price determination will take into consideration the economic conditions of the natural gas field; and
- Subsidised gas price, which is intended for certain sectors (such as for the poor or selected industry sub-sectors).

Since Indonesia does not have a gas price index, the market has a wide range of gas prices as benchmarks differ from one another. Besides the cost of production, the government considers a few other factors to establish the gas price such as purchasing power, gas infrastructure availability and potential creation of added value to the economy.

In order to boost industrial growth, Indonesia issued Presidential Regulation No. 40 of 2016 in order to allow gas to be sold at a lower price for certain industrial sectors including petrochemical, fertilizer, ceramics, oleo chemical, steel, gloves and glass. Following the President regulation, the Minister of Energy and Mineral Resources released the Ministerial Regulation No. 16 of 2016 on Procedures for pricing for a specific user. The regulation aims to determine the special gas price for these industry sub-sectors, provided that the current price is not economically feasible for these industries or exceeds USD 6/mmBtu. In order to get a special gas price, the company must first be audited for eligibility and get a recommendation from the Ministry of Industry before further evaluation by the Ministry of Energy and Mineral Resources.

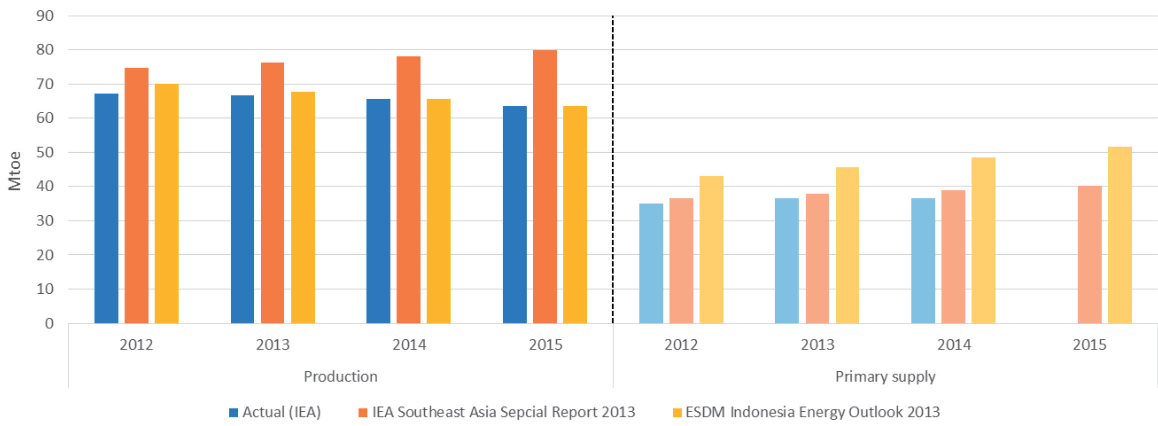
Past gas supply projections and actual supply

In assessing the development of the golden age of gas in Indonesia, it is worthwhile making a comparison of actual data and projections made in 2012/13 (Figure 4.5). Two past projections – the IEA's Southeast Asia Energy Outlook – World Energy Report Special Outlook 2013 and ESDM's Indonesia Energy Outlook 2013 were chosen.

The IEA's projections for gas production were higher than actual production by nearly 25% while the projection made by ESDM closely matched the actual data. However, in primary energy supply, the opposite is true, since IEA's projection closely matched the actual data compared with the ESDM projection. Regardless of the comparison results, the answer to the golden age of gas question posed by IEA is quite clear, at least for now, that Indonesia has not yet entered the golden age of gas.

However, given that Indonesia has a lot of unconventional gas resources and potential, the original question may be changed to "when is Indonesia going to enter the golden age of gas?" To make the golden age of gas materialise in Indonesia, the economy will need to divert its gas exports to the local market, which is in line with future government plans. The conversion of the Arun liquefaction terminal to a regasification terminal in 2015 proves that the government is trying to divert some domestic LNG production to use by local consumers.

Figure 4.5 • Actual and projected gas demand in Indonesia, 2012-15



Source: IEA (2016), IEA (2013) and ESDM (2015d)
Note: Since IEA and ESDM reports do not provide yearly data in their publications, APERC used the CAGR derived from the forecast demand to determine 2013-2015 data.

Factors contributing to lower gas demand

Macroeconomic uncertainties

In the period 2011-2014, Indonesian macroeconomic conditions were fairly stable, with economic growth averaging 5.8% per annum. The government has planned several projects in the power, fertilizer and petrochemical sectors which consume a lot of gas. The construction of gas-fired power plants was realised according to plan but in many cases, delays in constructing gas infrastructure meant some industries need to run their factories and power plants with more expensive fuel such as oil. This delay caused a few fertilizer and petrochemical plants to run below optimal efficiencies which subsequently pushed lowered productivity. Despite this hiccup, natural gas demand is expected to grow in the future. Additionally, since 2012 the volume of gas used in the economy has exceeded the amounted exported.

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 high on the power planning agenda.

In 2015, the National Energy Policy (KEN) prioritised the use of energy that is produced locally, improves energy resiliency and security, and reduces CO_2 emissions. These targets were then translated into National Electricity Master Plan (RUKN) through the implementation of an Electricity Supply Business Plan (RUPTL). For 2016-2025, the RUPTL set a target to limit the use of coal fired power plants to a maximum share of 50%.

The same RUPTL set a 25% target for new and renewable energy (that includes nuclear power) and a 24% share target for gas. Given that the construction of nuclear power has been postponed indefinitely by the government, while renewables are expected to be able to cover only a 20% share, the government decided to shift the remaining 5% share to gas which subsequently increased its share of the target to 29% (PLN, 2015).

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 will not be able to compete with big hydropower or geothermal power plants. However, given that RUPTL has set a target of a 29% share of the total generation mix, there is still room for gas to grow in the future.

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 constructing new infrastructure is quite slow. For instance, there are cases where some gas power plants needed to switch to oil to generate electricity, and delayed development of fertilizer and petrochemical plants because of lack of gas infrastructure.

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, 2015e).

Production and resources governance

Among the barriers, identified by the government, which hampered gas production in Indonesia, 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 dedicated regulation dealing with both (PwC, 2016). GR 79 divided upstream players into four main categories, depending on the difficulty of the field being developed. Since the inception of GR 79 in 2010, several 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 make necessary amendments.

In terms of deep water and marginal gas development, in order to attract investors the government is considering extending the development contract period to 50 years, which will cover exploration, development and production (ESDM, 2016a).

Access to resources

Indonesia had limited exploration success from 2011-2014. Among the factors that may have contributed to this situation are low internal rate of return (IRR) and insufficient open data available for companies to do their research. Although some of the data are 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 but only provides a platform for such a study (ESDM, 2016a).

Lack of exploration in deep water and low production from marginal fields contributed to the decrease in gas production. Development of unconventional gas is still in its infancy, however this resource will be able to improve Indonesia gas production in the future. In order to increase oil and gas reserves, the Geological Agency of the Ministry of Energy and Mineral Resources signed a memorandum of understanding with the state-owned company, PT Pertamina EP, to conduct geological explorations related to oil and gas resources (ESDM, 2016b).

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. As of 2016, Singapore has the capacity to import 9 Mtpa while Malaysia has capacity to import 3.8 Mtpa with an additional 3.5 Mtpa expected to be added in 2019/2020 (SLNG, 2016 and PETRONAS, 2012 and 2014).

Pricing mechanism

As discussed above, there are two gas price categories – market price and subsidised. Since the government introduced gas price incentives for certain industrial sectors, gas demand is expected to increase in the future. Gas prices can be reduced by increasing efficiency in eight gas distribution systems and by reducing state revenue. In addition, the decline in gas prices will not affect the revenue received by the contractor (ESDM, 2015f).

Conclusion

Indonesia, as one of the largest gas producers in the APEC region, has a huge potential to increase its own gas consumption. Endowed with huge conventional and unconventional gas resources, Indonesia is gearing itself towards a higher gas share in the energy mix. Domestic gas consumption is expected to continue to increase because of higher demand in the power, fertilizer and petrochemical industries as well as in the transportation and residential sectors.

The government has developed many initiatives and programs in order to overcome gas supply challenges. Though some of the initiatives and programs are for long-term targets, a few of them such as amending regulation related to gas extraction, are expected to show immediate impact. The Indonesian government, together with the private sector, is pushing for better gas infrastructure in order to have a reliable gas supply. Projects such as regasification terminals, FSRU and pipelines are expected to help Indonesia improve its gas uptake in the future. With smooth project implementation and efficient resource development, Indonesia may be able to achieve higher gas penetration in the future. This leaves us with a question that is worth examining again in the future – has Indonesia entered the golden age of gas?

CHAPTER 5

CASE STUDY: JAPAN

Introduction

Located in East Asia, Japan comprises several thousand islands, the largest of which are Honshu, Hokkaido, Kyushu and Shikoku. Most of its land area, approximately 377 800 square kilometres (km^2), is mountainous and thickly forested. Japan is the third-largest economy in the world after the United States and China. Its real GDP in 2014 was approximately USD 4 437 billion (2010 USD purchasing power parity [PPP]). In 2014, Japan's population of 127 million people had a per capita income of USD 34 902 (Table 5.1). The GDP decreased by 0.2% in 2014 compared with 2013. Since indigenous energy resources are modest, Japan imports nearly all of its fossil fuels to sustain economic activity. As of the end of 2014, the proven energy reserves included approximately 44 million barrels of oil, 21 Bcm of natural gas and 350 million tonnes (Mt) of coal.

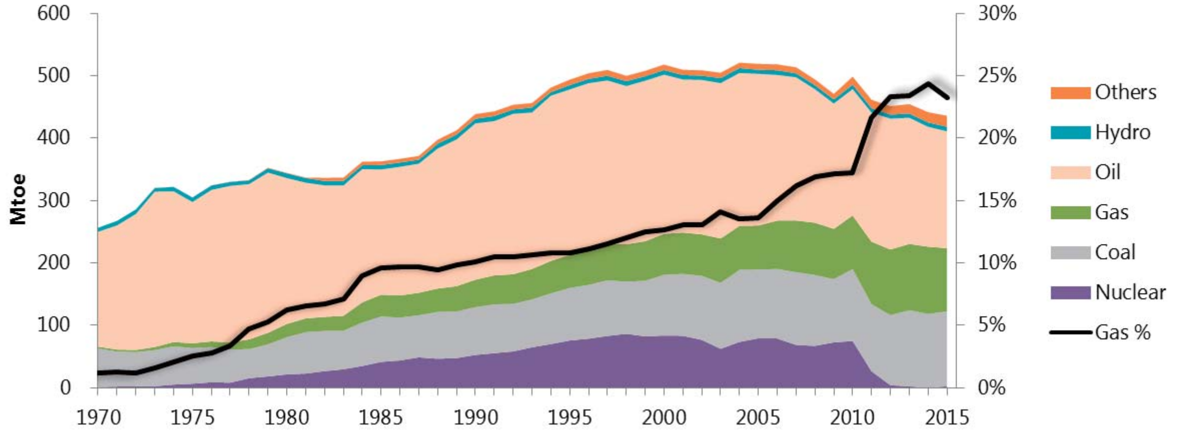
Table 5.1 • Japan key data and economic profile, 2014

Key data[a]		Energy reserves[b]	
Area (km^2)	377 800	Oil (million barrels)	44
Population (million)	127	Gas (billion cubic metres)	21
GDP (2010 USD billion PPP)	4 437	Coal (million tonnes)	347
GDP (2010 USD PPP per capita)	34 902	Uranium (kilotonnes U)	–

Sources: a. EGEDA (2016); b. BP (2016).

In 2015, Japan's total primary energy supply was about 436 Mtoe, 1.3% less than in 2014. By fuel type, oil contributed the largest share (43%), followed by coal (28%) and natural gas (23%) (IEA, 2016a) (Figure 5.1). Domestic gas demand was met almost entirely by imports in the form of liquefied natural gas (LNG) (BP, 2016), from Australia (21%); Qatar (18%); Malaysia (17%); Russia (10%) and other economies. LNG imports to Japan comprised 36% of the total global LNG trade in 2014. Domestic reserves stand at 21 Bcm, which is less than one-quarter of the annual consumption in 2015, and are located in the prefectures of Niigata, Chiba and Fukushima. In the primary energy supply, natural gas accounted for only 1.2% in 1970, but increased to 10.1% in 1990, 16.2% in 2007 and 23.3% in 2015 (IEA, 2016a).

Figure 5.1 • Change in primary energy supply and gas share in Japan, 1969-2015

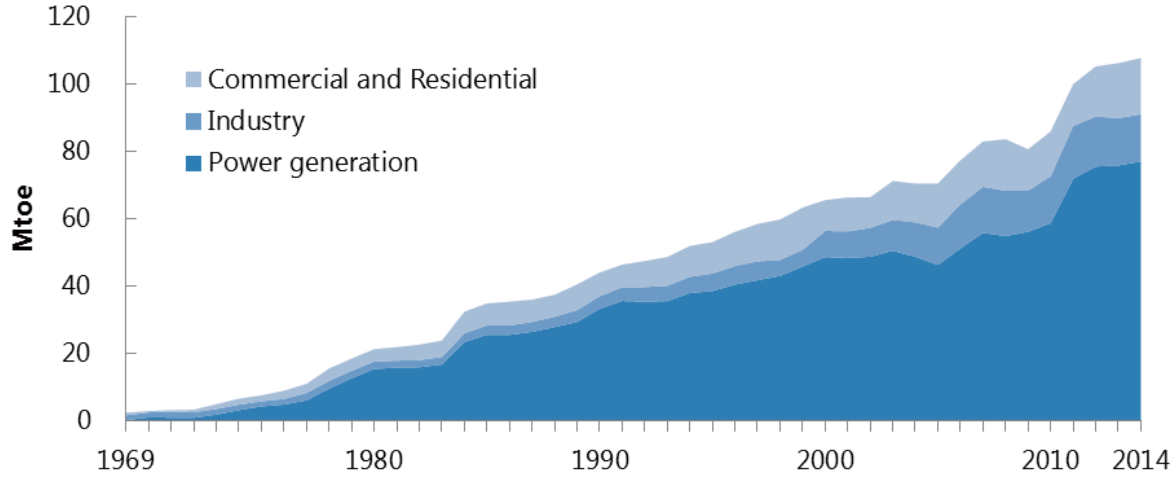


Source: IEA (2016a)

Natural gas in Japan

Natural gas demand has grown consistently since Japan began importing LNG in 1969 for city gas 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. In comparison with other fossil fuels such as oil and coal, natural gas is a cleaner energy source since it emits less carbon dioxide (CO_2) and nitrogen oxide (NO_X) during combustion. Natural gas is mainly used for electricity generation, followed by distribution as city gas and use as an industrial fuel (Figure 5.2).

Figure 5.2 • Natural gas use by sector in Japan, 1969-2014

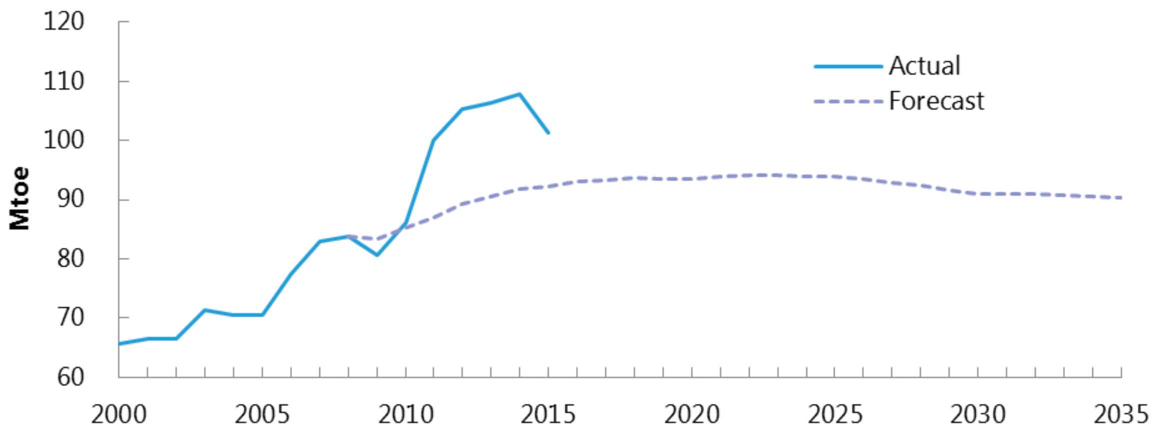


Source: IEA (2016a)

Projected and actual natural gas demand

IEEJ forecast in November 2010 that the demand for natural gas would gradually increase up to 2020, but the actual increase in demand is more than 10% to 20% higher than this forecast (Figure 5.3). This is because there was a huge increase in the operation of natural gas thermal power plants due to the shutdown of nuclear power plants following the Great East Japan Great Earthquake in 2011, causing a roughly 30% increase from 58.8 Mtoe in 2010 to 77.1 Mtoe in 2014 (IEA, 2016a). As summarised in Chapter 1, from a global perspective, natural gas use has not increased as initially anticipated, but in Japan, it was assumed that there would be no large increase in demand. However the shutdown of its nuclear power plants changed the equation.

Figure 5.3 • Forecast and actual gas demand in Japan, 2000-15



Source: IEA (2016a) and IEEJ (2010)

Natural gas in overall policy

Strategic energy plan

The positioning of natural gas in Japan's energy policy has been laid out mainly in the *Strategic Energy Plan* that the government publishes every three years. The latest *Strategic Energy Plan* was approved by the Cabinet in April 2014, and it positions 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, 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 (Table 5.2).

Table 5.2 • Positioning of natural gas in Japan's Strategic Energy Plan, 2003-14

Plan	Policy
October 2003 Strategic Energy Plan	Promote the acceleration of the shift to natural gas while taking into account the balance with other energy sources such as oil, coal and nuclear power.
March 2007 Strategic Energy Plan (first revision)	Continue to promote the spread of natural gas while taking into account the balance with other energy sources such as oil, coal and nuclear power.
June 2010 Strategic Energy Plan (second revision)	It is an important energy source for the early realisation of a low-carbon society in the future. The shift to natural gas should be promoted through the acquisition of upstream interests to ensure a stable supply and encourage fuel conversion in the industrial sector, using cogeneration, and promoting the technical development of fuel cells and disseminating it internally and externally.
May 2014	In the future, fuel prices will be determined through competitive pricing due to the

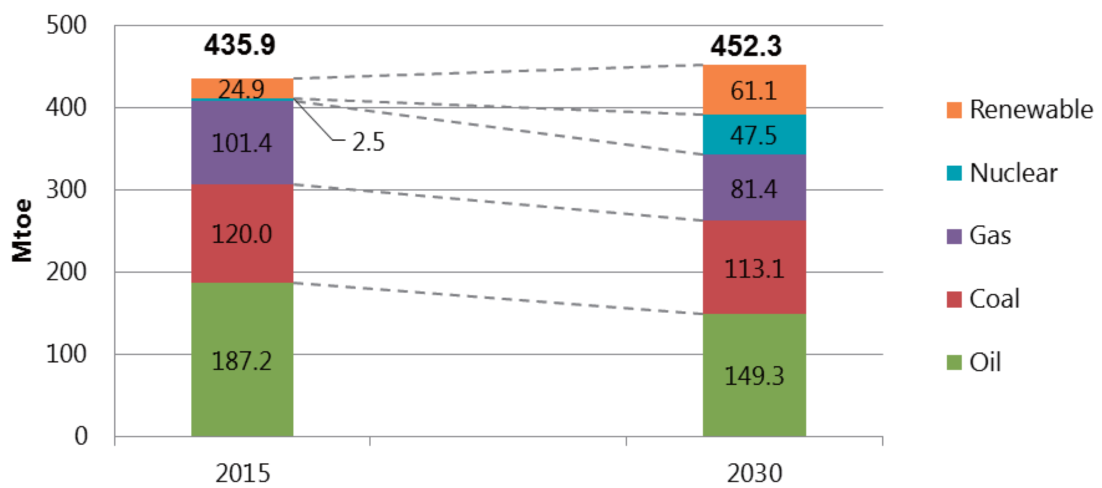
Strategic Energy Plan (third revision)	shale revolution, and a shift to natural gas is expected to proceed in various sectors. Therefore, natural gas is an important energy source whose role is expected to expand. Therefore, it is important to promote cost reduction by diversifying the supply sources, etc. while avoiding overly depending on it as a power source. From the viewpoint of global warming countermeasures, it is also important to encourage a steady shift to natural gas in the industrial field, etc. by diversifying the way of utilisation, including the use of the gas for local-level distribution of power sources through cogeneration systems, etc. as well as its use as a hydrogen source, and to promote the advanced usage of natural gas, such as combined cycle thermal power generation.

Source: IEEJ

Long-term energy supply and demand outlook

The revised *Strategic Energy Plan* in June 2010 (second revision) called for increasing the shares of nuclear power and renewable energy to 24% and 13% respectively by 2030, while leaving the share of natural gas at 16%. In response the Great East Japan Earthquake, the forecast of the energy supply and demand (*Long-Term Energy Supply and Demand Outlook*) for 2030 which was formulated by the Ministry of Economy, Trade and Industry in July 2015, increased the share of nuclear power and renewable energy in the primary energy supply from 10% to 11% and from 13% to 14% (0.4% and 8% respectively in 2013) in 2030, while decreasing the share of natural gas to 19% (24% in 2013) (Figure 5.4).

Figure 5.4 • Japan's primary energy supply outlook, 2015 and 2030



Source: IEA (2016 a), Ministry of Economy, Trade, and Industry (2015)

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.

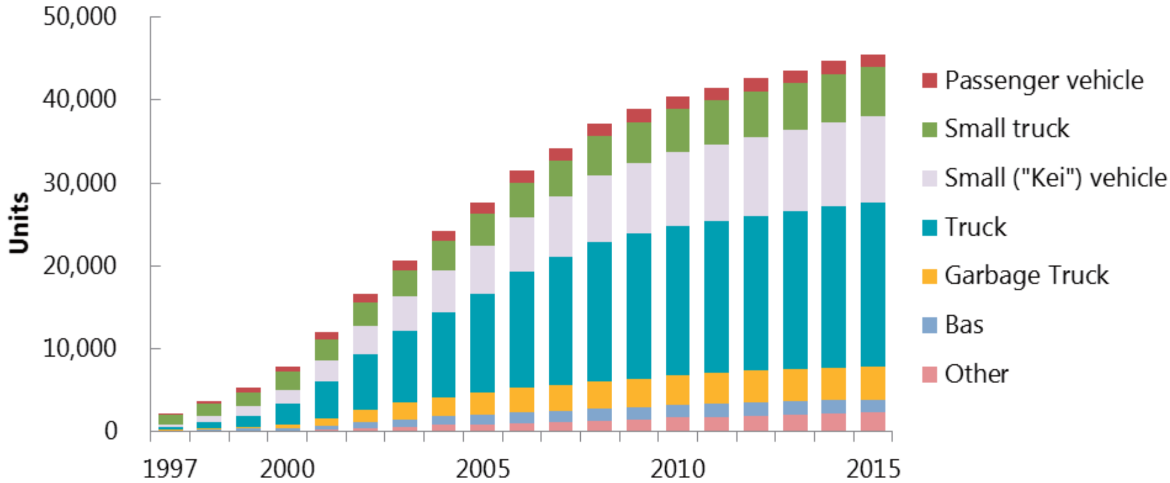
Subsidies

The Ministry of Economy, Trade and Industry initially allocated 838.4 billion yen (up 5.3% from the previous year) in energy measures special account subsidies for the FY 2016 resource and energy related budget. In order to optimise subsidy target area, efforts are underway in the industrial sector to convert oil and coal-based boilers and industrial furnaces to natural gas which will reduce CO_2 emissions and create energy savings. The "provider subsidy for the rationalisation of energy use" aims to reduce the costs of energy-saving/peak power measures at the factory/workplace level as well as energy-saving measures between companies by rebuilding existing facilities and systems, improving manufacturing processes and introducing an energy management system (EMS). In FY 2016, 51.5 billion yen in subsidies was allocated for this purposes. A separate 2.65 billion yen natural gas subsidy was provided to support part of the cost of converting existing facilities such as boilers, industrial furnaces and the like that use heavy oil and other fuels to advanced natural gas equipment.

In addition, to further expand cogeneration, an electricity and thermal energy subsidy for advanced use projects provided 1.5 billion yen to support the introduction of high-efficiency cogeneration equipment with market competitiveness.

Subsidies were also provided in the transportation sector to increase the adoption of NGVs (Figure 5.5). The Ministry of Land, Infrastructure, Transport and Tourism (MLIT) provides assistance for the adoption of next-generation vehicles such as CNG buses and trucks as part of the initiative to address air pollution and climate change. Another 360 million yen was allocated to promote low emission vehicles (environmentally-friendly vehicle introduction project), which subsidised the price difference between regular cars and CNG cars. Depending on the circumstances, such as whether a vehicle is retrofitted for CNG or a new vehicle is purchased, the subsidy covers up to half of the difference (Ministry of Land, Infrastructure, and Transportation (MLIT, 2017a).

Figure 5.5 • Natural gas vehicle growth in Japan, FY 1997-2015



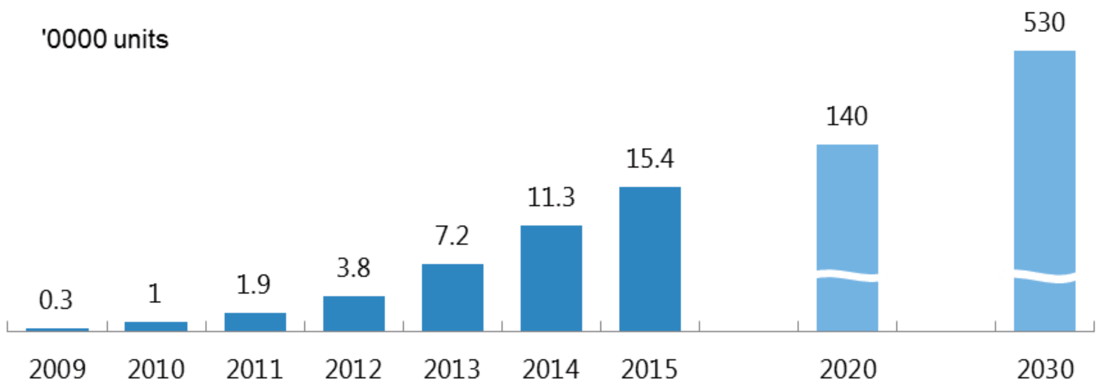
Source: Japan Gas Association web-site (2017)

Fuel cell vehicles (FCVs) are also being subsidised in the transportation sector. Like NGVs, they contribute to reducing CO_2 and other air pollutants in the transportation sector. Since FCVs only discharge water while driving, they are expected to be labelled as *the ultimate eco car*. The Ministry of the Environment (MOE) budgeted 1 billion yen in FY 2016 in subsidies for project cost, etc. including measures to control carbon dioxide emissions to provide assistance aimed at accelerating the spread of advanced environment-friendly vehicles, including FCVs and large natural gas vehicles. This project subsidises part of the difference between standard fuel efficiency level vehicles, it offers half of the difference for natural gas vehicles and up to two-thirds of the difference for fuel cell vehicles (MOE, 2017).

In FY 2016, 9.5 billion yen was allocated as a "subsidy for the introduction of consumer fuel cells (ENE FARM) with the aim of expanding the household use of fuel cells (ENE FARM) and establishing an autonomous market by subsidising part of the purchase cost. From FY 2016, the "reference price" and "bottom price" for consumer fuel cells was set to reduce equipment prices, and if fuel cell prices fell below these, the subsidy amount will be reduced, or in extreme cases, removed.

ENE FARM is exceptionally quiet and has excellent environmental performance because it generates electricity with hydrogen extracted from city gas by a chemical reaction. In addition, since it uses the heat created during power generation for hot water supply, it also greatly contributes to CO_2 reduction and energy saving. The *Strategic Energy Plan* (third revision) set a goal of 1.4 million units installed by 2020 and 5.3 million units by 2030 (Figure 5.6). The plan also includes support to induce cost reduction so that the fuel cell will be able to become competitive in the market.

Figure 5.6 • ENE FARM growth targets in Japan, 2009-30



**FY 2009-FY 2015 data: Fuel Cell Association (subsidies granted); *2020 and 2030 targets: Strategic Energy Plan (third revision)*
Source: Japan Gas Association (2017)

As for the development of the fuel cell itself, 3.7 billion yen was allocated for advanced technology development demonstration projects for fuel cell use in order to create high efficiency, high durability, low-cost fuel cell systems for the widespread use and expansion of applications of solid polymer fuel cells (PEFC) and solid oxide fuel cells (SOFC).

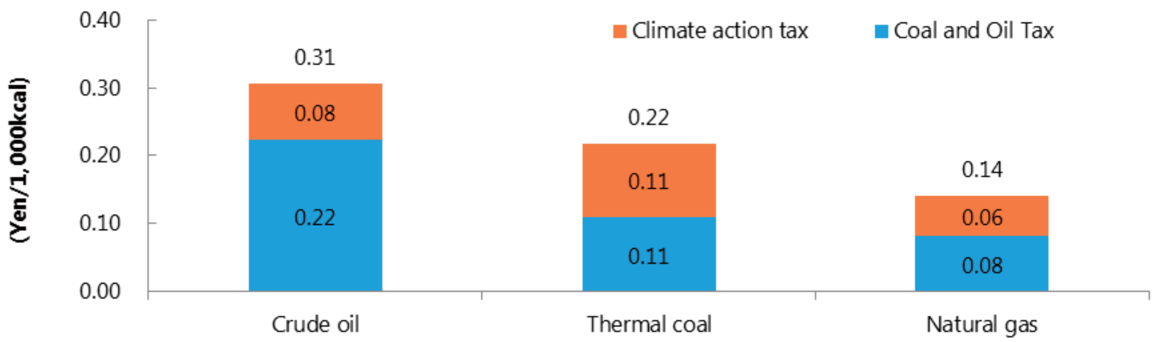
Taxation

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.[4] In October 2012, the government introduced a tax to mitigate climate change which is equivalent to 289 yen per ton of CO_2, and which is added to the conventional tax rate (Figure 5.7). With the introduction of the climate change mitigation tax, the

[4] 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.

tax rate added to coal, which emits high amounts of CO_2, becomes relatively large, and the tax rate for coal (steam coal) versus natural gas increased to 1.6 times 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.

Figure 5.7 • Petroleum and coal tax in Japan, as of 1 April 2016



Note: Calculated as crude oil (9,145kcal/L), steam coal (6,203kcal/kg), and natural gas (13,141kcal/kg)
Source: Ministry of Environment (2016)

In cases of individual use in the transportation sector, tax reduction and exemption measures have been introduced for automobiles with excellent exhaust gas performance and fuel efficiency. For natural gas vehicles, the eco car tax break nullifies the Car Acquisition Tax, and new cars are exempt from the Automobile Tonnage Tax when they undergo their first inspection (as of FY 2016). There is also the "Vehicle Tax green exemption" that reduces the Vehicle Tax for the following fiscal year for newly registered cars by 75% (as of FY 2016) (MLIT, 2017b). Even with the asset tax on automobiles, exemptions are in place for the standard tax. In addition, for fuel supply equipment for low-pollution vehicles (natural gas vehicle filling equipment and hydrogen filling equipment for fuel cell vehicles), the standard tax rate is reduced to two-thirds of the price for the first three years (as of FY 2016) (Road Transport Bureau, 2015).

For cogeneration facilities, the taxation standard is also reduced to 5/6 of the price for the first three years (as of FY 2016) (Advanced Cogeneration and Energy Utilization Center Japan, 2017).

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.

In 1995, the government liberalised the retail segment of gas for large users, which used to be monopolised by regional gas companies. With this system reform, large users with annual contracted gas consumption of more than 2 million cubic meters (Mm^3) (equivalent to 46 megajoules) are able to choose gas suppliers and be able to freely negotiate charges and other supply conditions.

Following that, in 1999, the scope of retail liberalisation was expanded to consumers that use more than 1 Mm^3 of annual contracted gas consumption. The expanded liberalisation also formalized the connection supply (assignment) system, and reviewed the regulation fee (the reduction of supply contract fees was changed from an authorisation system to a notification system). In 2004, the scope of retail liberalisation was further expanded to consumers that used more than 500,000 m^3 annually, along with placing the gas piping business under the Gas Business Act with the aim of enhancing and strengthening the rules on the consignment of gas piping. In 2007, this was expanded to customers with annual contracted gas consumption of 100,000m^3 or more (Table 5.3).

Table 5.3 • Expansion of the scope of gas retail liberalisation in Japan, 1995-2017

	From March 1995	From November 1999	From April 2004	From April 2007	From April 2017
Scope of liberalisation*1	Over 2,000,000m^3/yr	Over 1,000,000m^3/yr	Over 500,000m^3/yr	Over 100,000m^3/yr	Full liberalisation
Level of liberalisation*2	47%	52%	56%	63%	100%

**1 The requirement for the scope of liberalization is the annual contracted gas consumption.*
**2: The level of liberalization is the ratio of the large customer supply sales volume (cumulative) to the gas sales volume of the major 10 companies in fiscal 2012.*
Source: IEEJ (2016)

The total liberalisation of retail sales is planned for April 2017, and the city gas market is expected to be more competitive. As a result, gas usage is expected to increase through the revitalisation of competition and the creation of new services.

Challenges for developing gas demand

Use in the power generation sector

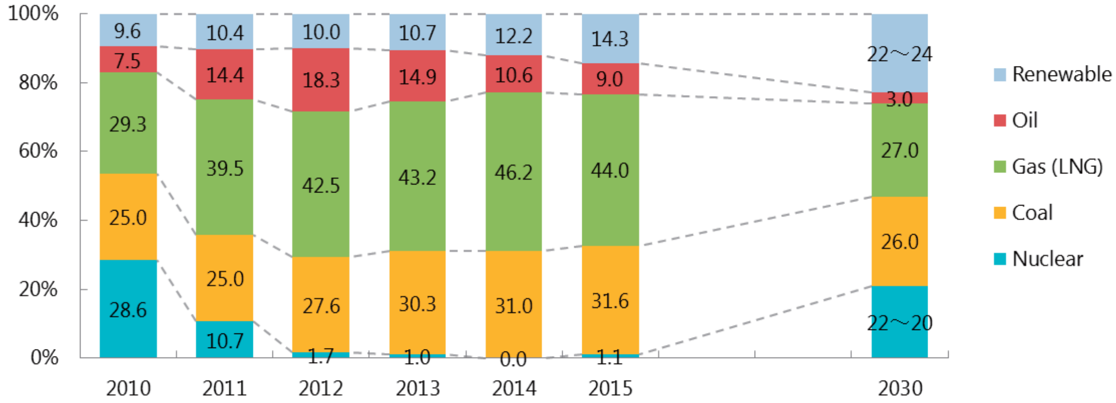
Gas-fired power has increased to over 40% of the generation mix since the Great East Japan Earthquake of 2011, but there is a strong possibility that gas share will decline in the future rather than expand. The *Long-Term Energy Supply and Demand Outlook* released in July 2015 shows the breakdown of 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.

Thus, based on the *Long-Term Energy Supply and Demand Outlook*, it is expected that future natural gas demand for power generation in Japan will decline although there are a few uncertainties that need to be addressed:

- As for renewable energy, although the adoption of solar power generation is progressing at a pace faster than anticipated, wind power, geothermal power, biomass and others may face an uphill battle with regards to site selection conditions and consultation with residents.
- For nuclear power, it is uncertain whether the re-starting of operations and the expected amount of power to be supplied will proceed smoothly.

As nuclear power and renewable energy are forecast to generate a combined 44% of electricity by 2030 (Figure 5.8), these uncertainties may create an opportunity for gas to compensate for any potential shortfall from these two fuels. Therefore, the role of natural gas in the electricity sector may be more important than its current position, especially in long run.

Figure 5.8 • Past and projected generation mix in Japan, FY 2010-30



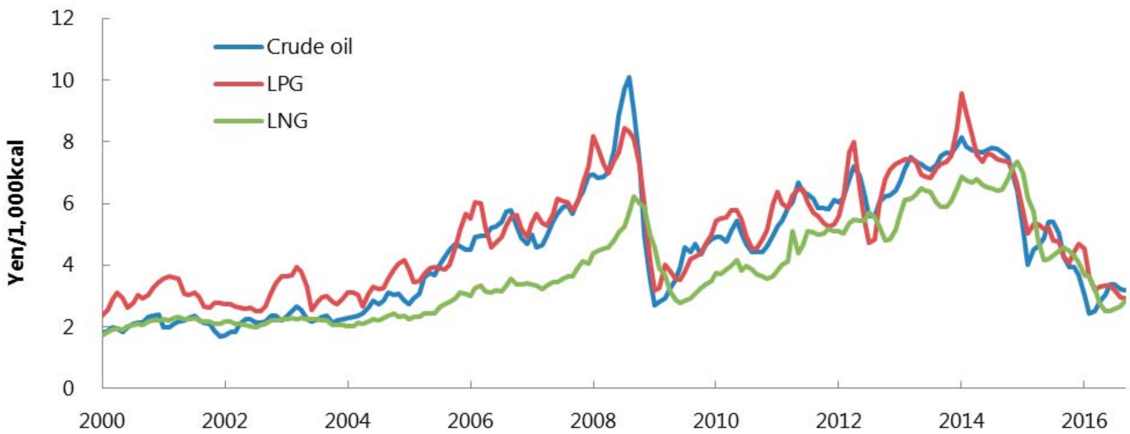
Source: IEEJ (2017)

City gas sector

Reduction of unit price based on raw material procurement costs

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 (Figure 5.9). For this reason, efforts are underway to focus on reducing running costs and to shift from other fuels to city gas.

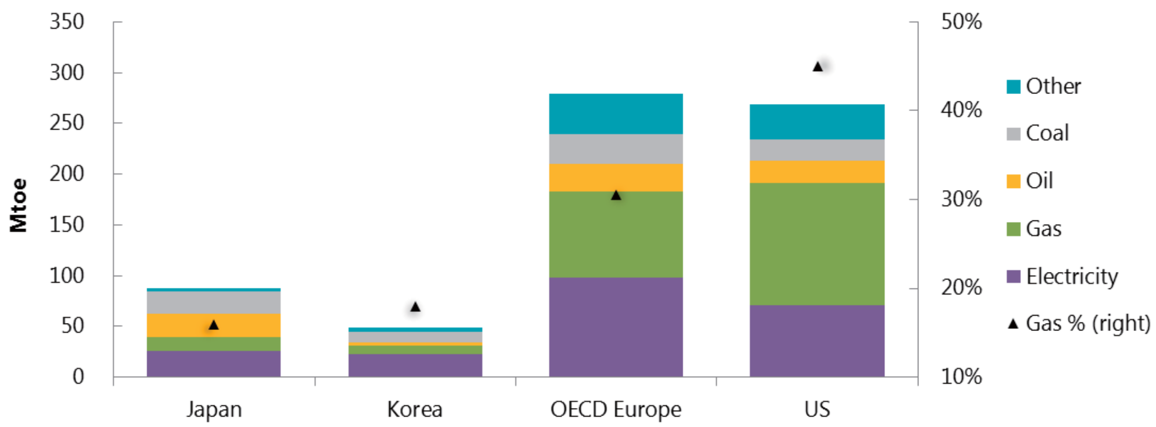
Figure 5.9 • Average imported CIF price (kcal basis) in Japan, 2000-16



Source: IEEJ (2017)

In 2014, the share of natural gas in Japan's final energy consumption was low compared with other economies and regions. This is particularly clear in the industrial sector where gas is 16% of the fuel mix in Japan, but 30% in OECD Europe and 45% in the United States (Figure 5.10).

Figure 5.10 • Industrial sector energy consumption and gas share in Japan, 2014

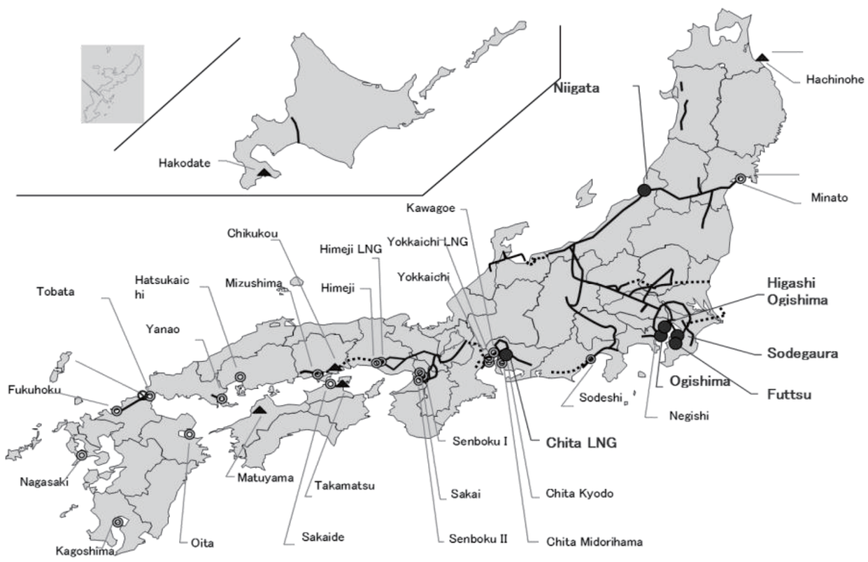


Source: IEA (2016a)

Although the *Strategic Energy Plan* (third revision) clearly states the necessity of promoting the shift to natural gas in the industrial sector, achieving this target may require not only subsidies that reduce the burden of initial investment, but lower gas prices so that businesses are willing to install new facilities that subsequently enable these business to recover their investment over time.

In order to reduce gas fees, it is essential to reduce raw material costs, which account for the largest portion of gas prices. All natural gas in Japan arrives as imported LNG, so reducing the cost of raw materials means reducing the price of LNG procurement. In many of Japan's existing LNG purchase contracts, the gas price is determined by a link to a crude oil price. Therefore, regardless of the demand and supply situation, the gas price has been determined in advanced. For this reason, it is important for Japan to diversify the import sources as well as to improve the pricing mechanism determination that better reflects the supply and demand of natural gas.

Figure 5.11 • LNG receiving terminals in Japan, 2016

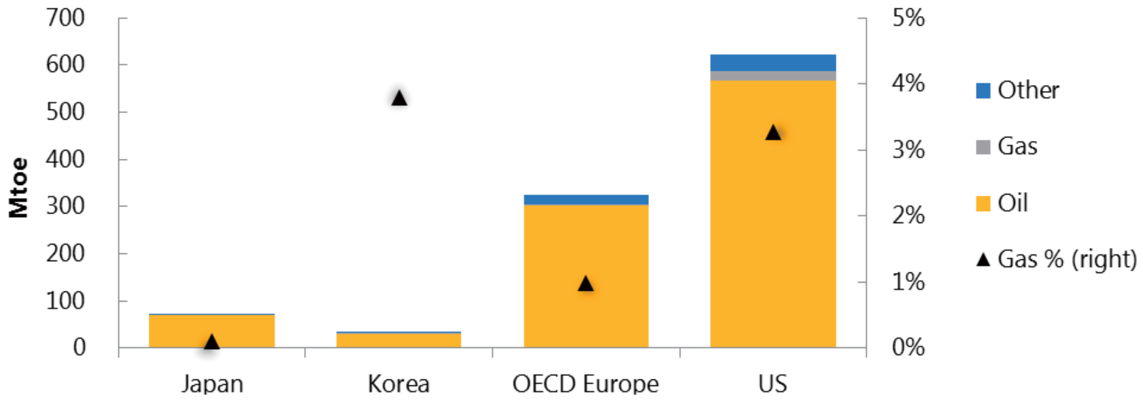


Source: IEEJ (2016)

Expanding gas demand in the transportation sector

Besides lowering gas fees, it is also necessary to promote infrastructure development in Japan. Demand will only able to expand further in the transportation sector, where gas only represents 0.1% of energy use currently, if there is enough infrastructure on the ground. Japan's share is low when compared with 3.8% in Korea and 3.3% in the United States (Figure 5.12).

Figure 5.12 • Transportation sector energy consumption and gas share in Japan, 2014

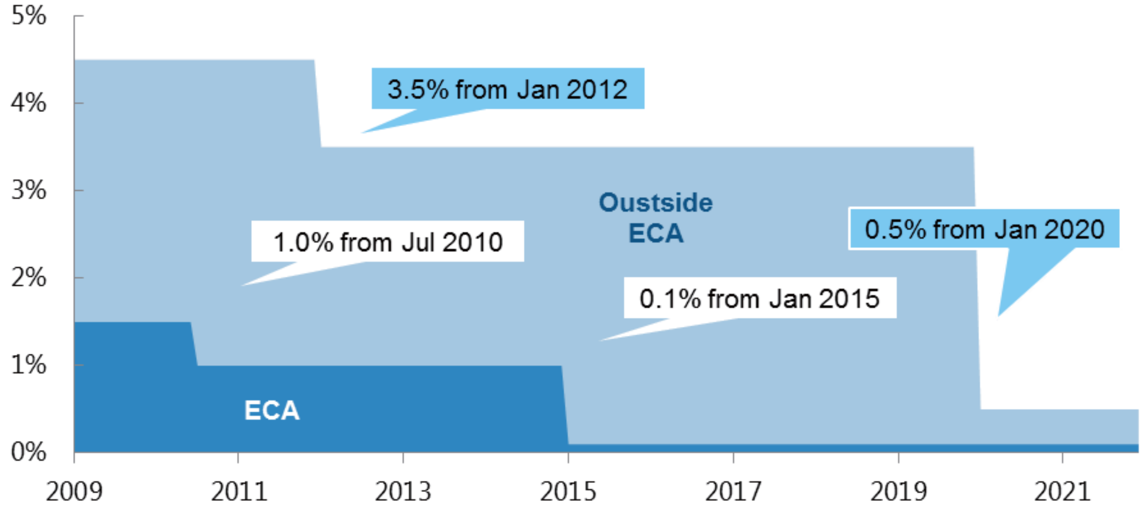


Source: IEA (2016a)

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 about 40,000 units (cumulative) by 2020, about 200,000 units (cumulative) by 2025, and about 800,000 units (cumulative) by 2030. Regarding hydrogen supply facilities, which are indispensable in order to promote FCVs, the construction of commercial hydrogen stations began in FY 2013. As of June 2016, there are 77 facilities in operation and another 14 facilities being planned. In addition to city gas companies, major oil companies and industrial gas companies are also involved in the operation of hydrogen stations (Fuel Cell Commercialisation Conference of Japan, 2016). In the revised version of the *Strategic Roadmap for Hydrogen and Fuel Cells*, the target for hydrogen stations is 160 stations by FY 2020 and 320 stations by FY 2025.

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 NO_X, SO_X, and CO_2. The North American region, North Sea, and the Baltic Sea are designated as Emission Control Areas (ECA) where strict SO_X regulations are in place. Under the latest regulation issued in October 2016, which mainly regulates the sulphur content, ships plying an ECA region need to meet the target of 0.5% or less of sulphur content by 2020 (Figure 5.13). Because of these developments, more attention is being given to LNG as a low sulphur fuel.

Figure 5.13 • Regulatory limit of sulphur content for ECA and outside ECA, 2009-21



Source: IEEJ

The first tug boat in Japan able to run on LNG was unveiled in September 2015. Tokyo Gas, as one of major gas players in Japan, supplied the fuel from LNG tanker trucks (Truck to Ship method) (Nippon Yusen Kaisha, 2015). On top of that, the Port and Harbour Bureau of MLIT initiated the "Steering committee for LNG bunkering at the port of Yokohama" in June 2016, aiming to make the Port of Yokohama an LNG bunkering hub. As companies such as Tokyo Gas and Nippon Yusen are also committee members, these companies are slated to compile specific measures in order to allow the LNG bunkering hub to materialise (MLIT, 2016).

Furthermore, efforts are being made to form energy networks that use cogeneration systems. Tokyo Gas plans to introduce a cogeneration system in industrial parks and plans to tackle energy conservation and CO_2 emissions by supplying electricity and heat (steam and hot water) to multiple companies (Tokyo Gas, 2016). In addition, Osaka Gas is working to save energy and reduce CO_2 emissions with plans to install ENE FARM systems in condominiums and introduce a mechanism for the company to purchase surplus electricity, thereby realising optimal energy use in the entire system (Osaka Gas, 2016).

Conclusion

Japan, which has almost no domestic natural gas production, has increased natural gas consumption through LNG imports. LNG was initially introduced for environmental purposes in the 1960s, but after the two oil crises of the 1970s, it has played a critically important role in diversifying energy sources. The Japanese government has deployed three policy tools to increase gas consumption: subsidies, taxation, and market reform. Japan's experience shows that even a country with negligible natural gas resources can be one of the major natural gas consumers in the world if appropriate policy arrangements are in place. Although natural gas consumption for power generation is likely to fall as more nuclear power plants are restarted, demand in the industry and transportation sectors still has room to grow. Ensuring cost competitiveness, as well as providing policy incentives for infrastructure investments, are key to realising further growth of natural gas demand in Japan.

CHAPTER 6

CASE STUDY: UNITED KINGDOM

Introduction

Located in Western Europe, the United Kingdom (UK) is a group of islands - including the northern one-sixth of the island of Ireland, located between the North Atlantic Ocean and the North Sea. Most of its land area, approximately 241 930 square kilometres (km^2), is rugged hills and low mountains which level to rolling plains in the south and east. The UK is the third-largest economy in Europe after Germany and France. Real GDP in 2015 was approximately USD 2 737 billion (2016 USD purchasing power parity [PPP]) and the population was 64.4 million people with a per capita income of USD 42 000 (CIA, 2017) (Table 5.1). The GDP grew 1.7% in 2013 and 2.8% in 2014, accelerating because of greater consumer spending and a recovering housing market after the 2007/8 financial crisis. The UK has some of the largest oil and gas reserves in Western Europe. As of the end of 2015, the proven energy reserves included approximately 2.8 billion barrels of oil, 205.4 Bcm of gas and 228 Mt of coal.

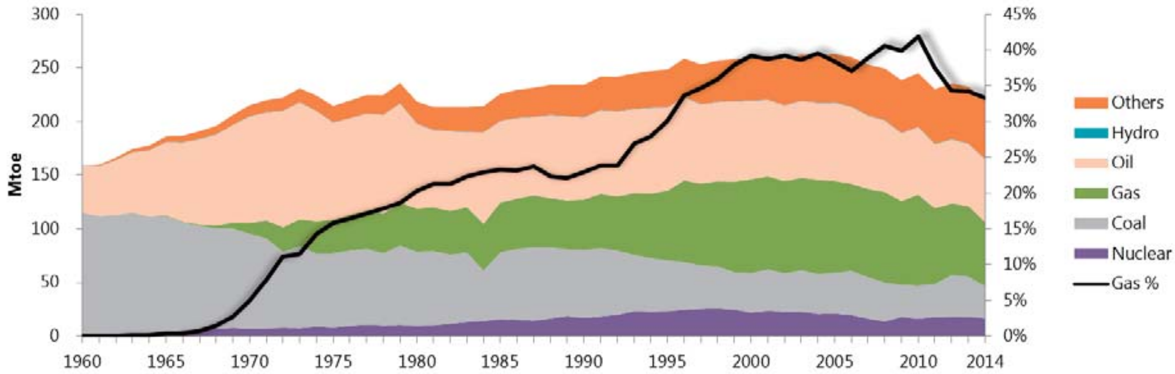
Table 6.1 • United Kingdom key data and economic profile, 2015

Key data		Energy reserves	
Area (km^2)	241 930	Oil (billion barrels)	2.8
Population (million)	64	Gas (billion cubic metres)	205.4
GDP (2016 USD billion PPP)	2 737	Coal (million tonnes)	228
GDP (2016 USD PPP per capita)	42 000	Uranium (kilotonnes U)	–

Sources: CIA (2017) and BP (2016)

Primary energy supply in the UK grew at 3% annually during the 1960s. Two oil crises and the subsequent depression ended that growth in the 1970s. With economic recovery since the 1980s, energy demand has been growing again, albeit at a slower pace, till the mid-2000s. Economic downturn triggered by the 2007/8 financial crisis, combined with a matured economy and energy efficiency improvement led to decreasing demand in the 2010s. The share of natural gas kept rising and reached 42% in 2010 before falling to 33% in 2014 as other fuels, particularly renewables, expanded (Figure 6.1).

Figure 6.1 • Primary energy supply and gas share in the UK, 1960-2014

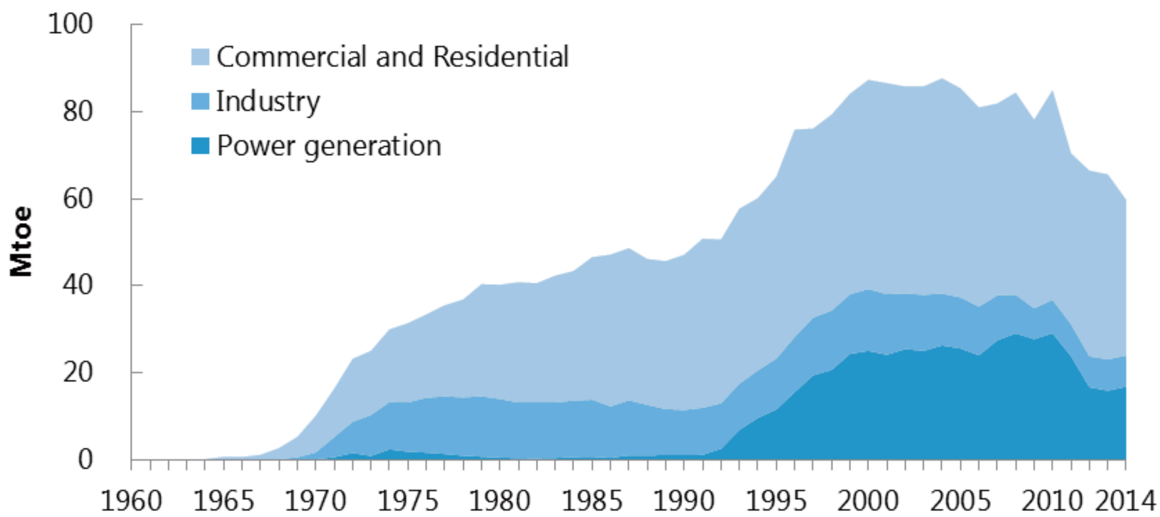


Source: IEA (2016a)

Natural gas in the United Kingdom

Natural gas demand in the UK has undergone dramatic change 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 pushed up demand significantly 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 big swing was caused by lack of competitiveness and government policy to promote renewable energy in the economy's power mix.

Figure 6.2 • Natural gas demand by sector in the UK



Source: IEA (2016a)

The UK is different from other case study economies in this report in terms of demand decline as well as 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 (Figure 6.2).

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.

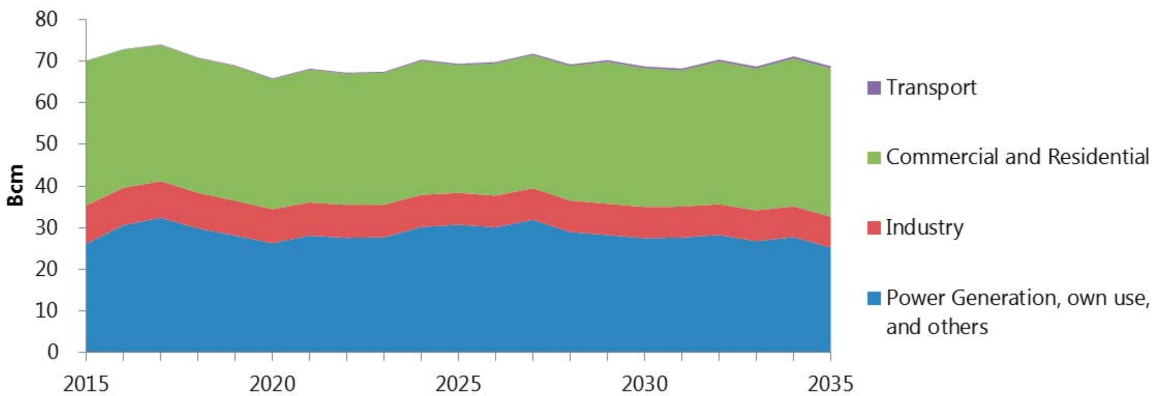
Natural gas in overall energy policy

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% in the power mix by 2020 (DECC, 2015a).[5]

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 the policy mentioned above focuses very much on decarbonisation, ironically it became one of the factors in the demand destruction of natural gas.

In the *Annual Energy Statement 2014*, the latest general energy policy paper, the government is 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 industry and household sectors, the demand of natural gas is likely to be stable while the transportation sector might create some new demand for natural gas though it will be marginal even in 2035 (Figure 6.3).

Figure 6.3 • Projected natural gas demand by sector in the UK, 2015-35



Source: DECC (2015a)

Gas infrastructure development

The UK possesses well-developed natural gas infrastructure with the about 8 000km 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 (Figure 6.4). The UK also has four LNG import terminals in operation.

[5] 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.

Although a distribution network was already developed to a certain extent prior to the 1960s, the high pressure transmission network only started to form after the discovery of North Sea gas. Most upstream offshore pipes were laid by producers while British Gas, a state-owned company, developed the onshore transmission and distribution network. British Gas played a primary role in developing the domestic gas supply infrastructure and when privatised in 1986, the network was already fairly developed and natural gas was available in most areas of the UK.

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 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.

Figure 6.4 • Natural gas infrastructures in the UK

Source: IEA (2016b)

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 pipeline. Privatised British Gas was required to transfer 1.2 Bcm/y in 1992-1995 and 0.6 Bcm 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). Thus, 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 the UK gas infrastructure is priced in accordance with NBP. As NBP became a spot price, the price became volatile which necessitated a hedging tool for producers and consumers. In response to that, Intercontinental Exchange (ICE) listed an NBP futures contract in 1997.

Demand development

Natural gas had an enormous potential demand as a means of tackling air pollution in the 1950s. Nevertheless, it was obviously the discovery of North Sea gas resources in the 1960s that underpinned the use of natural gas in the UK. At that time, there were twelve Gas Area Boards which were state-owned and monopolised the manufactured gas supply in each designated area. Those Boards were merged and became British Gas in 1972 in order to give the UK gas industry a more centralised structure. Gas Area Boards and later British Gas were granted a right to acquire land compulsory for pipeline construction by the Pipeline Act 1962 and Gas Act 1986, which certainly helped demand development.

When the "dash for gas" happened in the 1990s, the UK government indirectly promoted natural gas use for power generation by encouraging incumbent power companies to buy electricity from new generators whose main fuel was natural gas (Winterson and Wright, 2010). One could argue that gas-fired power plants improved in the early 1990s because of stable gas prices and through commercialisation of highly efficient combined cycle gas turbines, or otherwise new entrants would not have invested in these plants. However, the generation cost of gas-fired power plants is still higher than coal-fired, and therefore, the government indirectly promoted gas demand that was not necessarily competitive as a fuel for power generation, under the name of competition policy.

Today the focus of UK energy policy is decarbonisation and there is little policy incentive to promote the use of natural gas that is cleaner than coal but still a fossil fuel, except for combined heat and power (CHP) and NGV.

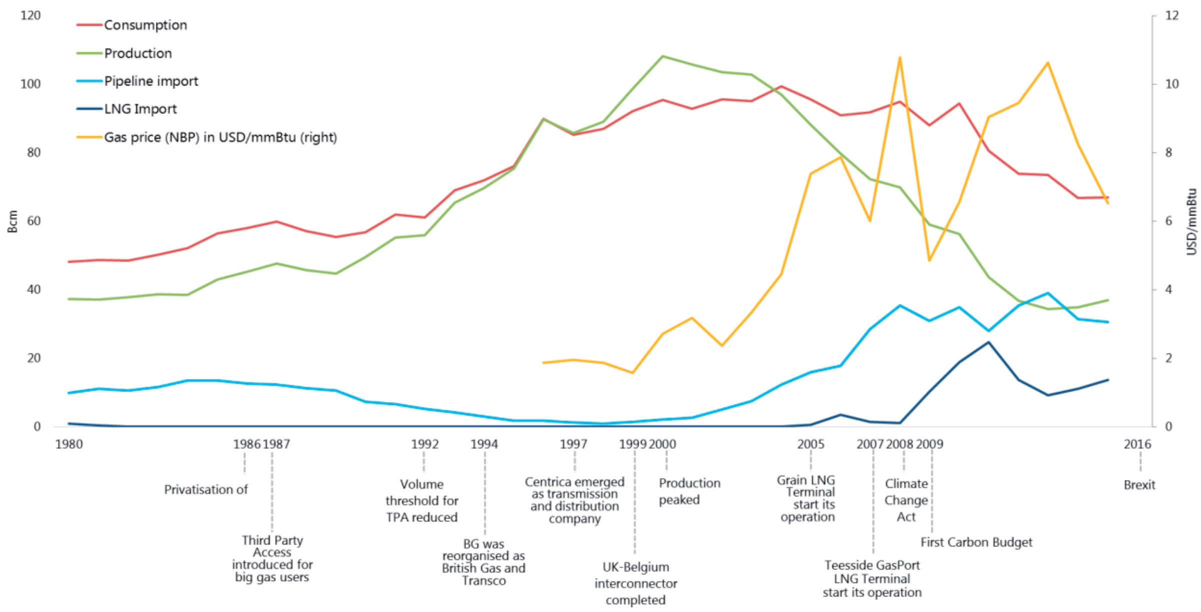
Relation between gas production, market liberalisation and demand

UK gas production peaked in 2000 and by 2013 had fallen to around one-third of this volume. However, a slight increase in production was seen in 2014-15 (Figure 6.5). 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 contribute 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 – through pipeline and LNG imports – managed to sustain demand to 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_2 emission.

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

Figure 6.5 • Domestic gas production, demand and imports in the UK, 1980-2016

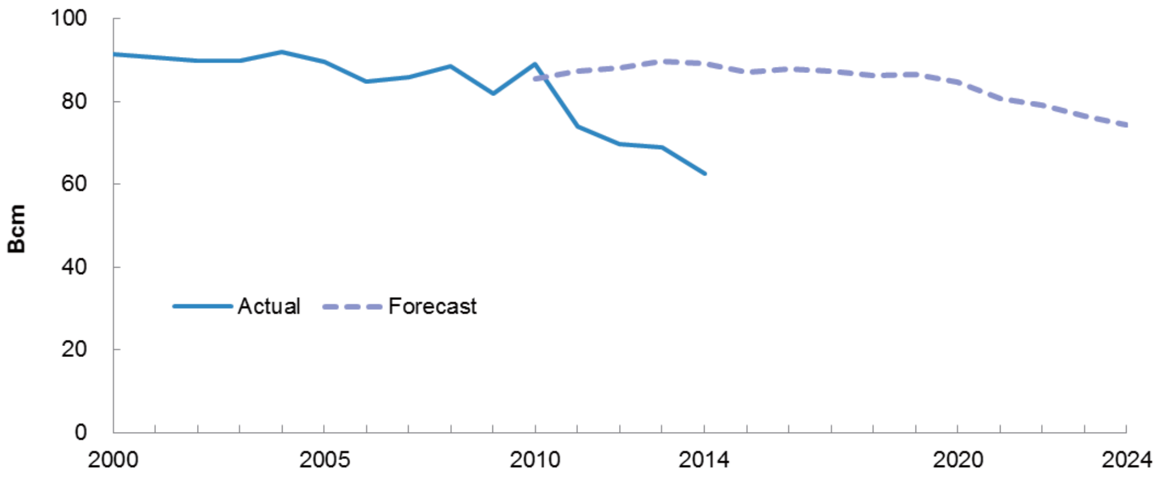


Source: Cedigaz (2016), BP (2016) and IEA (2008)

Forecast and actual demand

National Grid, the gas transporter in the UK, is obliged to publish a natural gas demand outlook every year. In the 2010 outlook, called the *Ten Year Statement*, gas demand was projected to contract gently by 2020. The demand dipped in 2009 because of the economic downturn (Figure 6.6). However, in 2010 demand bounced back strongly. This rebound was caused not only by overall energy demand recovery but also by cheap spot LNG that rushed into Europe that year. Nevertheless, the actual demand decreased dramatically after 2010, and it was 63 Bcm in 2014, 30% lower than the outlook in the *Ten Year Statement* 2010.

Figure 6.6 • Gas demand forecast (2010) and actual demand in the UK



Source: National Grid (2010) and IEA (2016)

Three factors caused this demand destruction. First, overall energy demand was weak and had already stagnated before the economic downturn mainly because of a mature economy and improved energy efficiency. Second, the competitiveness of natural gas declined especially for power generation because of a combination of high gas prices, increased coal imports from the US where coal was squeezed out due to the shale gas revolution, and a low carbon price which incentivised power generators to burn more coal. Third, robust government support for renewables. As a result, natural gas became uncompetitive and that decreased demand as gas was pushed out of the power mix. Lower prices could see natural gas demand recover marginally. However, the consensus is that demand is not likely to exceed the 2004 peak of 92 Bcm again.

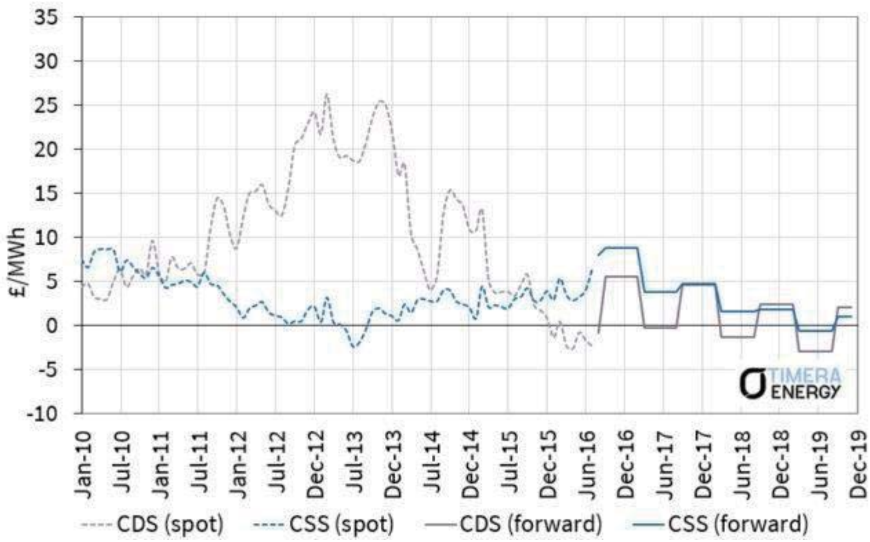
Challenges for demand development

Power generation

Demand destruction was mainly caused by the declining competitiveness of natural gas for power generation as mentioned above. Although demand has shown a slight recovery in recent years, competitiveness in the power generation sector will remain the key for natural gas demand to grow or at least limit further decreases. 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.

The government responded to this situation by drawing up "Electricity Market Reform" in 2013. While this reform envisages a set of measures, a carbon floor price and a capacity mechanism are important in relation to natural gas demand for power generation. The carbon floor price scheme imposes GBP 15.7/t-CO_2 in 2013, GBP 30/t-CO_2 in 2020, and GBP70/t-CO_2 in 2030 on power generators and other GHG emitting companies, in addition to the existing carbon price under the European Union Emission Trading Scheme (EUETS). The carbon floor price effectively increases the competitiveness of natural gas over coal for power generation. Timera Energy, a consultancy, argues that a carbon floor price, as well as a lower gas price and a higher electricity price result in improved clean spark spreads (CSS)[6], higher utilisation rates of gas-fired plants and gas demand recovery for power generation. Timera Energy envisions that gas-fired plants will be more competitive than coal-fired with improved CSS and lower clean dark spreads (CDS)[7] at least in the summer till 2019. Unless the carbon price under the EUETS surges autonomously to a significant extent, gas demand for power generation in the UK will continue to need support like a carbon floor price.

Figure 6.7 • Spot and forward CSS and CDS in the UK, 2010-19



Source: Timera Energy (2016)

An alternative would be to have a capacity mechanism which invites generators to bid their capacity, and requires electricity retailers to purchase spare capacity from generators. Since generators will be paid by retailers even if no capacity is utilised during the contract duration, the government hopes a capacity mechanism will provide incentives for generators to invest in new power plants, including gas-fired.

Other sectors

In the 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).

[6] Wholesale electricity price minus gas-fired generation cost with carbon price adjustment
[7] Wholesale electricity price minus coal-fired generation cost with carbon price adjustment.

Domestic 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, the result of this exploration is unclear (DECC, 2015a). Despite these policies, it is unlikely that natural gas production will bounce back in the UK.

Conclusion

The UK is one of the largest natural gas consuming countries in the world although the government has never adopted a specific policy to promote natural gas consumption in its energy mix. This is because the economy gave a high priority to climate change action, energy supply security, and market liberalisation. What made the UK a major gas consuming economy was the discovery of North Sea oil and gas fields and the development of a nation-wide pipeline network. Because natural gas is difficult to transport, it is economic to consume it near where it is produced. The UK's experience suggests that natural gas consumption can be expanded by "supply-push." Development of an extensive pipeline network in the UK, another important factor that increased the gas consumption, was feasible because the pipeline business was undertaken by a state-owned entity. The UK experiences suggests that market liberalisation and natural gas utilisation can advance simultaneously, but it is feasible only when an extensive pipeline network is in place. The role of government is critically important to develop such large infrastructure.

CHAPTER 7

CASE STUDY: VIET NAM

Introduction

Viet Nam is located in the centre of South-East Asia. It is bordered by China to the north, Laos and Cambodia to the west, and the East Sea (Bien Dong) and Pacific Ocean to the east and south. It has a land area of 330 967 square kilometres (km2) with diverse geography and an exclusive economic zone stretching 200 nautical miles from its 3 260km coastline (excluding islands). Being in a tropical monsoon zone and profoundly affected by the East Sea, Viet Nam has warm weather, abundant solar radiation, high humidity and seasonal rainfall.

Viet Nam had a population of 90.7 million and a gross domestic product (GDP) of 477 billion USD 2010 PPP in 2014 (GSO, 2016). With real GDP growth at robust level since the early 1990s and a 6% per year average growth from 2010-2015, Viet Nam is generally among the fastest developing economies in the world. Its economic structure has gradually changed through growth of the industry and service sectors, expanding from 62% of the economy in the early 1990s to 73% in 2015 (GSO, 2016) (Table 7.1). Major exports have diversified with more manufactured products, such as electronics, machinery and vehicles (28% of total exports in 2014) as well as textiles, garments and footwear (21%), in contrast to traditional fishery products, coffee and rice (nearly 10%) and crude oil (nearly 5%) (Viet Nam Customs, 2015). Viet Nam's political stability, consistent efforts in enabling competition and in balancing market-led growth and equity, and its expanding export sector are often cited as the main reasons for its high GDP growth. Although Viet Nam's population growth has slowed (about 1% per year during 2009-2014), its golden population structure[8] is anticipated to be maintained through 2050. Positive macroeconomic conditions have, and are expected to continue, providing solid grounds for strong continued growth in Viet Nam's energy demand and supply.

Table 7.1 • Viet Nam key data and economic profile, 2014

Key data [a, b]		Energy reserves [c, d]	
Area (km^2)	330 967	Oil (billion barrels)	4.4
Population (million)	91	Gas (billion cubic metres)	600
GDP (2010 USD billion PPP)	477	Coal (million tonnes)	150
GDP (2010 USD PPP per capita)	5 262	Uranium (kilotonnes U)	3 900

Sources: a. GSO (2016); b. EGEDA (2016); c. BP (2016); d. NEA-IAEA (2016).

Viet Nam is endowed with a diverse energy resources, such as oil, gas and coal, as well as renewables. As of the end of 2014, Viet Nam's proven fossil energy reserves were 4.4 billion barrels of oil, 600 Bcm of gas and 150 Mt of coal. OECD estimates the identified recoverable resources of uranium at about 3 900 kilotonnes. Among renewable energy resources, the economic and technical potential of hydro is estimated at 95–100 terawatt-hours (TWh)/year or 25 GW capacity, of which the technical potential of small hydropower (less than 30 MW) is about 7 GW (MOIT, 2015a).

[8] Golden population structure means that for every one dependent person there are at least two working people.

Natural gas in 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 some other industries has driven demand for natural gas. There are three unconnected regional natural gas markets in Viet Nam:

- the Northern market with one supply system and 0.5 Bcm of capacity with gas from the Ham Rong and Thai Binh fields;
- the South East market with supply sourcing from about 20 oil and gas fields in the Cuu Long and Nam Con Son basins. Associated gas and natural gas are transported via two offshore pipeline systems with a current combined capacity of 10 Bcm;
- the South West market with supply from fields jointly administered by Viet Nam-Malaysia in the Malay-Tho Chu Basin. The 2 Bcm capacity gas pipeline system began operating in 2007, 12 years after the operation date of the first gas supply system in southern Viet Nam.

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).

Policies, regulatory frameworks and governance structure

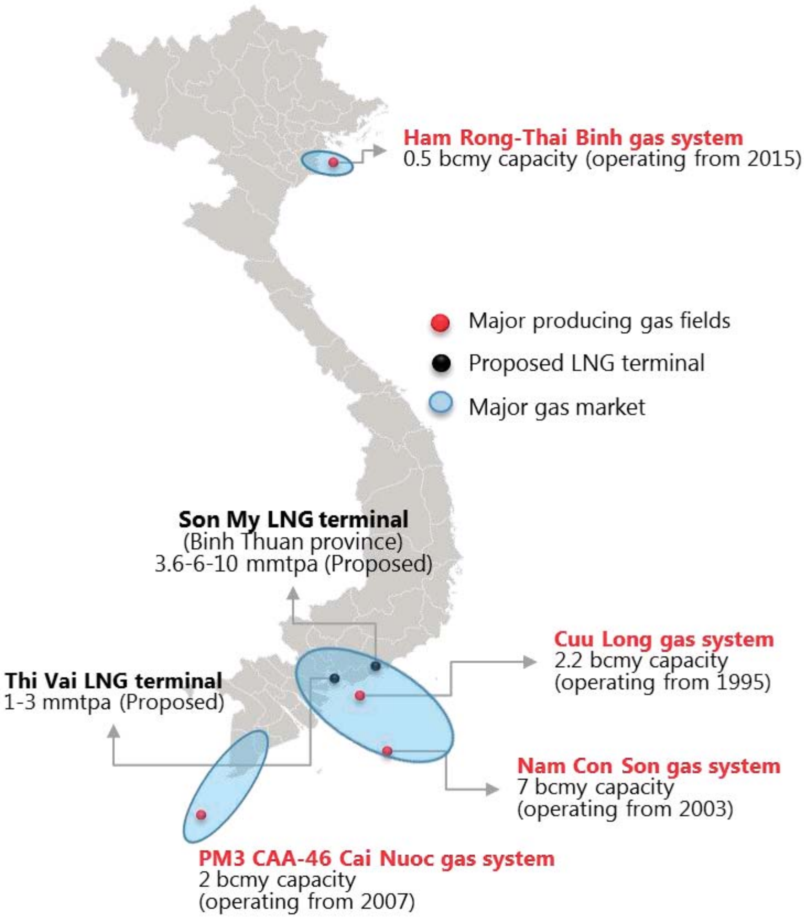
In Viet Nam, natural gas as well as other natural resources are under public ownership and subject to unified management by the government. The government regulates the natural gas sector through a legal structure that includes the Petroleum Law, the Gas Business decree, the Strategy for Development 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.

The government promotes the development of the natural gas industry with regulations and through international cooperation projects based on market mechanisms. Upstream to downstream gas businesses are open to foreign investment. However, 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).

Exploration and production

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. Figure 7.1 shows existing major gas sources in each market area. 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%).

Figure 7.1 • Viet Nam gas production and proposed LNG terminals, 2015



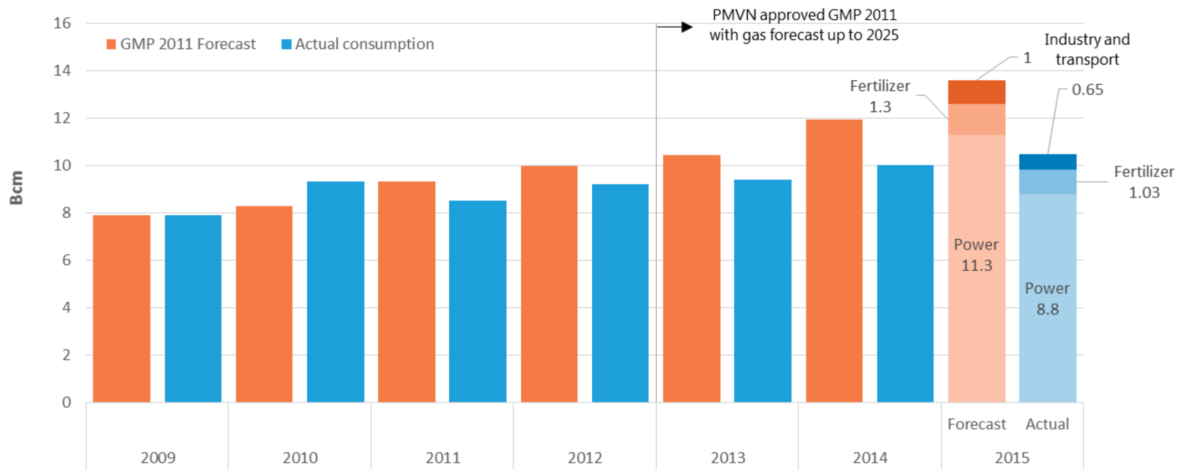
Source: PVGas (2016b) and LNG World Shipping (2016)

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.

Gas demand

Consumption of 10.45 Bcm of dry gas in 2015 is about 77% of the forecast level in the Viet Nam gas master plan that was approved in 2011 (GMP 2011) (Figure 7.2). Growth of Viet Nam's natural gas market during 2010-2015 was only 5% per year on average, lower than the government's forecast level of 9% per year. Actual consumption in all three sectoral markets was also lower than its forecast level. Of the shortfall for the year 2015, the power market contributed 82% of total difference, the industrial/commercial market comes next at 11%, and finally the chemical market at 7%.

Figure 7.2 • Viet Nam forecast and actual gas demand, 2009-2015



Note: PMVN – Prime Minister of Viet Nam. GMP – Gas Master Plan
Source: PMVN (2011a) and PVGas (2012 & 2016a)

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 this 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 tight links to the government's master plans for the development of the power, petrochemical and other sectors. Natural gas has 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.

Gas market

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 concluded 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/chain, 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.

Forecast to 2035

Under the government's direction, PVN and PVGas are preparing for the development of two major gas projects in order to have additional gas supplies of about 7–10 Bcm per year from Block B, Ca Voi Xanh field and adjacent sources to southern and central markets beyond 2020 (PMVN, 2016 and PVN, 2014). Viet Nam also has plans to develop new infrastructure for importing LNG, first in the south, to diversify gas supply sources and ensure energy supply security for the period beyond 2015 (PMVN, 2014; MOIT, 2015b).

In January 2017, the Prime Minister approved Viet Nam's GMP through 2025 and orientation to 2035 (PMVN, 2017). Viet Nam set targets to expand the domestic natural gas market to 11-15 Bcm annually in the period 2016-2020, to 13-27 Bcm per year during 2021-2025 and 23-27 Bcm per year during 2026-2035. LNG imports will complement domestic natural gas sources to ensure sufficient fuel supply for the 15-19 GW of gas-fired power plants expected by 2025 and 2030 respectively, as well as for accelerating the use of natural gas in other sectors (PMVN, 2016). Natural gas used as fuel for power generation accounts for 70-80% of total gas supply. Viet Nam's natural gas production is forecast to be 10-11 Bcm annually until 2020, then increase to 13-19 Bcm per year during the period 2021-2015, and 17-21 Bcm per year by 2026-2035, with the LNG import requirement estimated at 1-4 Bcm per year during the period 2021-2025 and 6-10 Bcm per year during 2026-2035.

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.

Macroeconomic uncertainties

Macroeconomic assumptions for the period 2010-2015 made in the National Power Master Plan 7 (PMVN, 2011b) 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. In regards to natural gas markets in Viet Nam, this situation hurt both the demand and supply sides, as they resulted in delays of a series of upstream (such as Block B which was expected to have first gas delivery in 2014 in GMP2011, several fields in the Cuu Long basin and the Thai Binh field in the North), midstream (such as the Nam Con Son 2 pipeline, the Block B-O Mon pipeline and gas processing plant in Ca Mau) and downstream projects (such as the Phu My ammoniac plant and O Mon CCGTs planned to be built in the Southern region during 2010-2015).

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 infrastructure

In Viet Nam, CCGT, 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.

Conclusion

Viet Nam, as one of the economies with some of the largest untapped gas reserves in the ASEAN region, has a huge potential to increase its own gas production and consumption. With higher demand in the power, fertilizer, petrochemical industries as well as in transportation and residential, domestic gas consumption is expected to continue to increase in the future although actual consumption did not increase as fast as expected from 2011 to 2015 in the government's gas master plan.

Many initiatives and programs has been developed by the government in order to overcome gas supply challenges in Viet Nam. Some are for long-term targets while a few of them, such as improving gas supply governance, are expected to show immediate impact. As rapid economic growth is expected to continue, reliable gas supply will be very important for Viet Nam. With considerable gas production potential, supported by projects such as regasification terminals and distribution pipelines, Viet Nam is expected to be able to improve gas supply and demand in the future.

CHAPTER 8

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 challenging factors have been identified as barriers that hamper 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 policy response. It is a given that to expand gas demand, stable and low gas prices are a big help. 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.

The level of crude oil, natural gas and LNG prices traded in such international markets is not just limited to the global supply and demand balance of oil and natural gas, but is 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 cannot have a large effect on the price itself. Apart from some 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 the price in the international market. 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

As discussed in Chapter 1, 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 such as coal. 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 market liquidity and inflexibility owing to restrictions on the point of destination. However, these types of LNG transactions are generally agreed upon in the contract between the LNG seller and buyer, and the government cannot 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 deemed it illegal in that preventing the free flow of products harmed competition, and as of writing (February 2017), in Japan, the Fair Trade Commission is reviewing 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, so the government (via competition authorities) has a large role to play 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 also has the disadvantage of the necessity to develop more expensive usage and transportation infrastructure compared to oil, and it also emits more greenhouse gases than renewable energies. 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, to what extent it will be used in what field, and by when and how much it will be used.

With the government setting a basic policy, it is desirable that it formulates a more detailed usage plan. By establishing a clear plan on how the gas is going to be used, it 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, nuclear power as well as natural gas, but a clear-cut policy on to what extent natural gas thermal power will be developed and what supply infrastructure will be built for it will encourage investors in developing this field.

Construction of infrastructure

Natural gas demand will not grow if the supply infrastructure up 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 as mentioned above, and if a certain scale of demand can be confidently expected, investors may be willing to invest to build these infrastructure. However, it is 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 to this, 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. However, better coordination between governments will help to push the construction of these pipelines faster. Besides that, establishing the route and setting usage fees will need better coordination too.

Promotion of natural gas use in the transportation sector should also be done to develop future natural gas demand, but in this regard too, its success or failure will depend on the development of infrastructure. In the Asia-Pacific market, if price differences between crude oil and 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 the possibility that LNG, which contains almost no sulphur content, will be increasingly used by marine vessels. To achieve such demand for transportation, it is necessary to enhance the convenience of natural gas vehicles and LNG carriers to consumers, particularly by installing gas supply bases for fuel. Governments can make a significant contribution to promoting the use of natural gas in Asia if they can concentrate on the development of such 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 high 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 rational. 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 as mentioned above.

By reflecting gas's lower emissions, a carbon pricing method that promotes gas use is also possible. To this end, emissions trading and 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 prices and prevented natural gas consumption becoming preferable to coal serves as a 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. In the Asia-Pacific region, there are economies with abundant shale gas resources, such as China. So 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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