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LNG Markets Study

PFC Energy

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Background: Purpose and Scope of Study

The LNG Canada Project, developed by LNG Canada Development Inc. ("LNG Canada" or "the Applicant"), on behalf of, Shell Canada Limited, as managing partner of Shell Canada Energy ("Shell"), Diamond LNG Canada Ltd. (an affiliate of Mitsubishi Corporation) ("Mitsubishi"), Kogas Canada LNG Ltd. (an affiliate of Korea Gas Corporation) ("KOGAS"), Phoenix Energy Holdings Limited (an affiliate of PetroChina Investment (Hong Kong) Limited) ("PetroChina") (together the "Project Owners"), is proposing to export liquefied natural gas (LNG) from Western Canada. This study, prepared by PFC Energy in relation to the proposed export project, provides an analysis of LNG market conditions globally, particularly the Asia-Pacific,[1] drawing on public information and over 27 years of experience in oil and gas consulting. Included in the report is a detailed independent analysis of LNG and gas demand and supply forecasts for a select number of target destinations: Korea, Japan and China (the home markets of the parent companies of three of the Project Owners) as well as the broader Asia region. PFC Energy has leveraged public information, its internal databases and knowhow to examine the timing and extent of LNG demand in these regions, the strengths that each Project Owner brings to LNG Canada, and competing sources of LNG supply in the region.

This study has been prepared with available information as of June 5, 2012.

[1] *PFC Energy defines the Asia-Pacific region as the LNG markets of China, India, Indonesia, Japan, Korea, Malaysia, Singapore, Taiwan, Thailand, and Vietnam.*

Executive Summary

I. Demand for liquefied natural gas (LNG) in the Asia Pacific region is forecasted to grow significantly to 2020 and beyond; by 2020, gas demand in Japan, Korea and China is forecasted to exceed secured supply by 49 million tons per annum (mmtpa), a volume that grows to 112 mmtpa by 2025. This gap creates a large opening for suppliers to sell LNG into this region.

In 2020, gas demand in Japan, China, and Korea—the largest LNG markets in Asia—is projected to exceed supply by 49 mmtpa, a number that grows to 112 mmtpa by 2025 due to the expiration of active contacts and growing demand. Japan and Korea will need to either extend their existing LNG contracts (which are often signed on 15- to 20-year terms), sign new LNG supply agreements, or buy this gas from the spot market for LNG. China has other gas supply sources which it can draw on to help meet demand, including piped gas and production, but is still expected to be in significant measure reliant upon LNG.

	Forecasted Supply-Demand Gap by Year (mmtpa)		
Primary Regions	***2020***	***2025***	***2030***
Japan	**26**	**47**	**63**
Korea	**7**	**18**	**37**
China	**17**	**47**	**180**
Subtotal	**49**	**112**	**279**

Besides these primary target markets, LNG Canada is also well positioned to sell LNG to India, Taiwan and Southeast Asia.

- **Taiwan** has a clear need for incremental LNG volumes beyond existing contracts in the realm of 8 mmtpa by 2020.
- **Singapore** is another potential market, although if pipeline imports from Indonesia and Malaysia remain constant, the window for further LNG imports will open only after 2020.
- **Thailand's** LNG needs will also hinge on pipeline imports from Myanmar (and the growth thereof), but unlike Singapore, Thailand has not finalized any long-term LNG contracts to secure its needs.
- **Vietnam's** strong projected growth in gas demand will quickly lead to a widening supply-demand gap unless the country can boost domestic production at a faster pace or rely more heavily on LNG imports.
- **India's** LNG import needs depend heavily upon domestic production, but there is considerable upside for LNG imports from 2020 onward – or earlier, if the country fails to reform pricing and achieve its domestic supply potential.
- **Indonesia** and **Malaysia** will both be importing LNG by 2020, but the scale of their needs will depend on domestic production, the level of regional imbalances and the pace of import infrastructure development.

II. **LNG Canada benefits from several attributes which make it an attractive project for investors and LNG buyers alike. These are likely to aid in project development and expedite the Project's completion.**

Besides price, LNG buyers care about a number of parameters – and in several respects, LNG Canada is an attractive project.

- Canada is an important new source of LNG supply for regions that are increasingly reliant on Australia to meet future growth, and where many historical suppliers are not expected to expand LNG exports.

- Canada offers portfolio diversification and thus has the potential to enhance the energy security needs of its offtakers. This is achieved in a number of ways: by adding a new supply source, by carrying less political and operational risk than many other competing sources, and by exposing offtakers to a new upstream environment.
- Western Canada is proximate to some of the world's fastest growing LNG markets. It takes 8-10 days to ship LNG from the Kitimat Port to Japan versus 13-15 days to ship from Qatar. The Project Owners are also well-positioned to take advantage of the low natural gas prices in North America (where natural gas is increasingly abundant from new sources, particularly shales).
- Canada's resource development policies allow companies to take an ownership interest in the entire value chain. The ability to secure equity in the entire value chain is a critical value creator and it also enhances security of supply, as buyers have direct knowledge of and participating interests in the projects that supply them. Unlike many LNG-exporting jurisdictions, where access to the resource itself is limited, Canada offers an opportunity to partake in the ownership of the resource itself and to own not just the midstream segments of the value chain but the upstream as well.

III. The Project's ownership structure is an asset that will aid in the successful marketing and development of LNG Canada.

LNG projects require several characteristics to succeed. Almost all LNG projects are joint-ventures with two or more partners. Successful projects tend to have partners that have experience in upstream development and in previous liquefaction projects. Joint ventures between buyers and sellers have become increasingly popular, as this structure provides buyers will greater supply security and allows sellers to more easily monetize their gas. This merging of the upstream and downstream segments of the LNG value chain fosters enduring relationships between buyers and sellers to the benefit of the project.

LNG Canada's project structure is a major asset in that regard and the Project's prospects are bolstered by its ownership structure. Shell, KOGAS, Mitsubishi, and PetroChina bring extensive experience in all aspects of the LNG value chain including upstream, liquefaction, shipping, regasification, and access for LNG output as well as access to technical, financial and commercial resources. Shell is one of the world's largest IOC natural gas producers and has extensive experience in upstream, liquefaction, shipping, and regasification. KOGAS is the main importer into South Korea, the second largest LNG market in the world. China is now one of the world's fastest growing gas regions; PetroChina is the largest overall gas supplier to that market and is quickly growing its LNG imports and regasification position. Mitsubishi has a long history in LNG supply and deep ties to Japan's LNG buyers.

As a result, the Project Owners in LNG Canada together have all of the attributes required for a successful Project.

IV. LNG Canada will face some, but not extensive, competition in the Pacific Basin.[2] The majority of the new liquefaction capacity expected online by 2020 has already been contracted to buyers.

PFC Energy projects that, by 2020, 118 mmtpa of liquefaction capacity will be added in the Pacific Basin and another 18 mmtpa of capacity will be added by 2025, on top of the 101 mmtpa of capacity online in 2011.[3] Despite this doubling of LNG supply by 2020, competition for markets is limited as a majority of this new capacity has already been tied to long-term contracts. LNG Canada is among a handful of projects projected to come online by about 2020 whose owners have not yet signed LNG sales contracts.

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[2] *PFC Energy defines the Pacific Basin as countries in northeast Asia (including Russia's Pacific coast), East Africa, Oceania, South Asia and Southeast Asia.*

[3] *This figure does not include the LNG Canada project.*

In addition, only a share of current Pacific Basin contracts due to expire before 2020—which includes 19 mmtpa of LNG supply from North West Shelf LNG (Australia), Tangguh (Indonesia), and Malaysia LNG—are likely to be extended from 2020 through 2030 at current levels due to gas supply constraints. In other words, buyers in the Asia-Pacific have a limited number of projects in the Pacific Bain from which to source LNG from 2020 to 2025 to meet their growing gas supply-demand gaps and LNG Canada is one of them.

Overview of the Global LNG Market

Natural gas provides approximately one-fifth of the world's energy. The global gas market is segmented into two transportation sub-categories: pipeline gas, which represents ~70% of the market by volume, and vessel-transported liquefied natural gas (LNG), which holds a ~30% share of the market. LNG exports grew at an annual rate of over 13% from 2000 to 2011, reaching 243 million tons per annum (mmtpa) in 2011 (Chart A).

Of this total, Asian economies, primarily Japan and South Korea, accounted for 63% of the market as (Chart B). While Japan made up 52% of Asia's LNG imports and 33% of global LNG imports in 2011, the center of gas demand continues to shift away from Organisation for Economic Co-operation and Development (OECD) countries toward non-OECD countries. Still, demand in the OECD continues to grow. In the OECD countries demand comes mainly from power generation; in the non-OECD, gas demand is driven by a broader pattern of economic development, industrialization and rising living standards.

There are an increasing number of countries that have either turned to importing LNG or plan to do so in the coming years. In Asia-Pacific, LNG demand has been growing steadily in China, India and Taiwan, while a number of countries just recently began importing LNG (e.g. Thailand, Indonesia) or have plans to do so soon (e.g. Vietnam, Singapore, Malaysia). Even countries which have traditionally been LNG exporters, such as Malaysia, Indonesia and countries in the Middle East, are planning to import LNG. In South America, there are more countries importing LNG than exporting it.

Chart A. LNG Exporter by Region, 2011 (243 mmtpa)

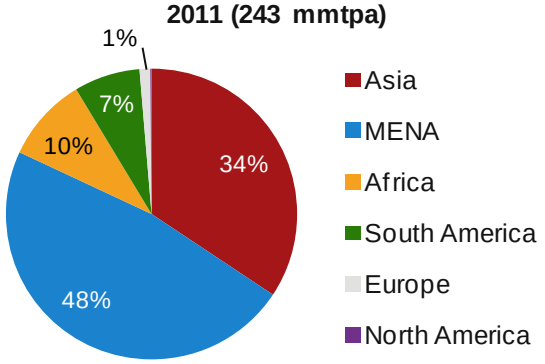
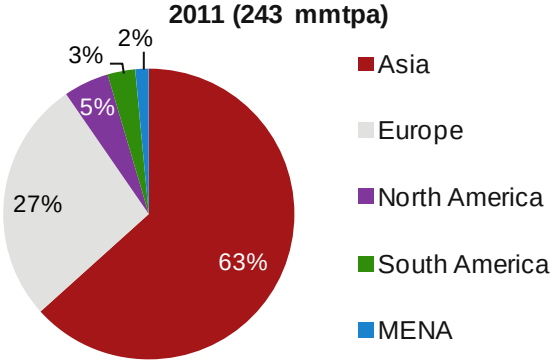


Chart B. LNG Importer by Region, 2011 (243 mmtpa)



Historically, the majority of LNG exports have been sourced from the Middle East and North Africa (MENA). Qatari exports alone accounted for 31% of global LNG exports in 2011. In terms of proposed LNG export activity, six countries account for 75% of liquefaction capacity[4]. If all of these projects moved forward according to their announced timetables, global LNG capacity would more than double to 595 mmtpa by 2020 and would be 626 mmtpa in 2025. However, based on a project-by-project risk analysis, PFC Energy believes that many of these projects face considerable development risks in moving forward. Based on this risked outlook assessment, PFC Energy estimates that global LNG liquefaction capacity will reach 445 mmtpa in 2020 – a full 150 mmtpa below announced capacity levels – and 484 mmtpa in 2025.[5] PFC Energy expects that the global market will be able to absorb all of this projected LNG supply.

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[4] The six countries proposing 75% of liquefaction capacity are: Australia, Canada, Iran, Nigeria, Russia and the United States.
[5] While this risked outlook allows PFC Energy to forecast long-term LNG supply through 2030, LNG demand by country is only forecasted in the near –term through 2013.

Overview of Primary Regions Asia: Japan, China, and South Korea

Given the involvement of Canadian affiliates of Mitsubishi, KOGAS, and PetroChina in the LNG Canada Project, Japan, South Korea, and China will be among the primary regions for its LNG output. Other potential Asia-Pacific regions for the LNG Canada Project's gas include India, Taiwan, and smaller Southeast Asian countries (e.g. Thailand, Indonesia, Singapore, Malaysia, and Vietnam).

Japan

Summary. Japan is the largest LNG market, importing nearly 79 mmtpa in 2011. The market has consistent, reliable buyers and LNG demand is expected to have moderate growth going forward. Post 2020, long-term LNG imports begin to fall off due to expiration of existing contracts, creating a projected supply-demand gap of 47 mmtpa by 2025 and 63 mmtpa by 2030. The main uncertainty in Japan's prospects for LNG demand is the government's revised energy policy, which is announced to be finalized in 2012. Japan's government is faced with a decision of how quickly and to what degree to bring back online or permanently leave offline its nuclear power plants and how quickly to scale up renewable energy sources, both of which will impact the gas demand. Greater use of nuclear power and renewable energy in electricity generation would suppress gas demand growth in the power sector. However, as it stands, the government favors having a lower share of nuclear power in the fuel mix, which creates a potentially large upside for gas. PFC Energy has assumed that Japan will permanently take offline a share of its existing nuclear power plants in a gradual manner, but that some plants will remain online in 2030.

Energy Demand by Sector and by Fuel

Historical Trends by Sector. Since 2000, Japan's primary energy demand has been flat (Chart 1-A). This has been due to slower GDP growth of 0.8% p.a. (per annum) on average, effects from the economic recession, and increased energy efficiency. Even before energy demand took a hit from 2007 to 2009, it was declining in industry and transport, thanks to gains in energy efficiency and lower per capita demand in transport. In contrast, energy demand from the power and commercial sectors has been growing, while energy use in the residential and the non-energy sectors has been flat.

Forecasted Final Energy by Sector. PFC Energy forecasts that even with GDP growth of 1.2% p.a. on average through 2030, final energy demand will remain flat.[6] Driving this trend are sector-wide energy efficiency gains and practically no population growth.[7] Also, Japan's economic structure has been shifting towards services, limiting incremental energy demand in industry, which has much higher energy demand than the commercial sector. Through 2045, the effects of declining population will cause energy demand to decline in the residential and transport sectors, while energy efficiencies will continue to drive down energy demand in the industrial and commercial sectors.

Forecasted Primary Energy by Fuel. While final energy demand is not forecasted to grow, the fuel mix is expected to change due to new policies for gas, nuclear, and renewable energy such as wind and solar. The government's energy policy is being revised after Fukushima, but has yet to be released, though Japan has indicated that it favors limited reliance on nuclear in the longer term. As a result, PFC Energy forecasts that the share of nuclear power in the fuel mix will decline from 15% in 2010 to below 9% in 2030[8]. Oil is also forecasted to account for a smaller share of total energy, while coal, renewables,

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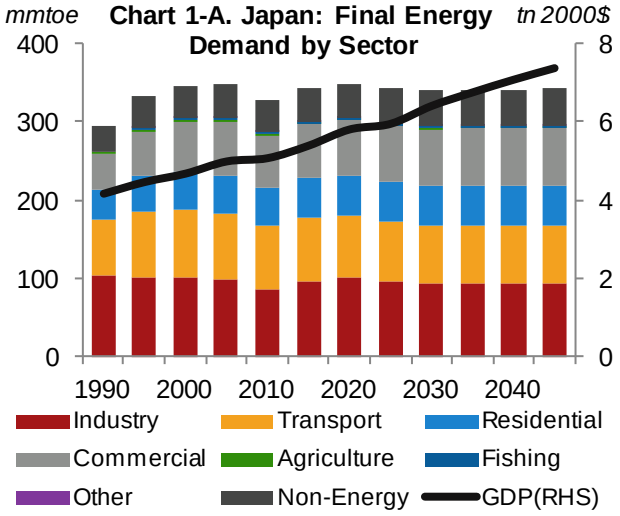
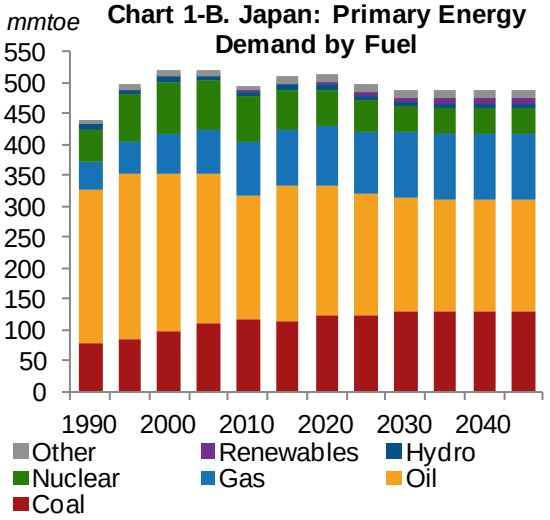
[6] *All growth rates referred to in this report are on a per annum, average basis.*

[7] *The United Nations Population Prospects (UNPP) forecasts that Japan's population will begin to decline in 2020.*

8 This forecast assumes that Japan will bring back online a number of its currently-offline nuclear power plants.

and gas will have a larger role in the fuel mix by 2030 (Chart 1-B). Through 2045, renewables (mainly solar and wind) are likely to make up an even larger share of the fuel mix, displacing some use of fossil fuels.





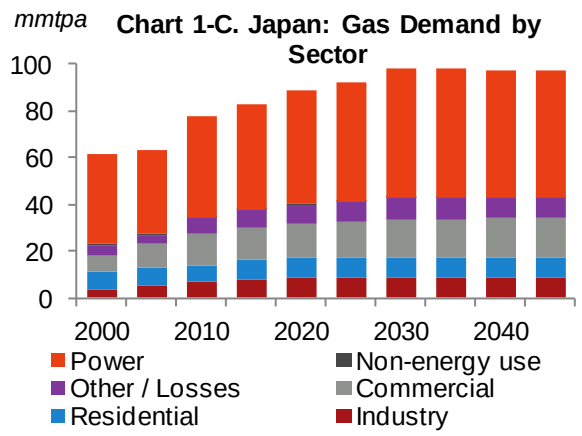
**Note: The difference between primary energy demand and final energy demand is mainly due to thermal efficiency losses and also includes energy industry own-use and other discrepancies.*

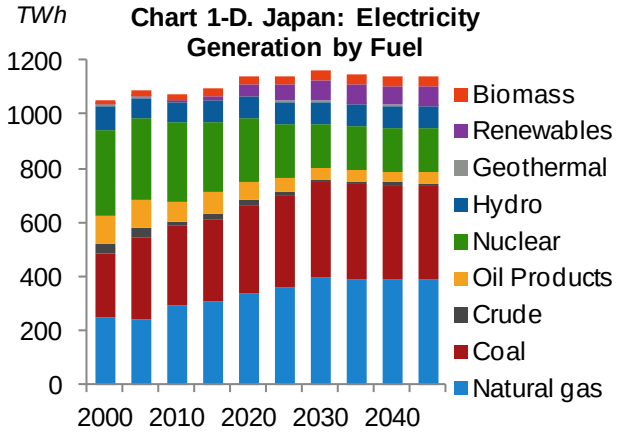
Natural Gas Demand Forecast by Sector

Historical. Gas demand rose by 3.4% p.a. from 1990 to 2000 and 2.5% p.a. from 2000 to 2010, much faster than total energy demand. The commercial and industrial sectors had the fastest growth in gas demand, as they have been substituting oil for gas. The power and residential sectors had slow but steady growth in gas demand from 2000 to 2010. After the nuclear disaster in March 2011, Japan turned to gas and oil products to make up for lost nuclear generation, causing gas demand in power to jump by more than 20% in 2011.

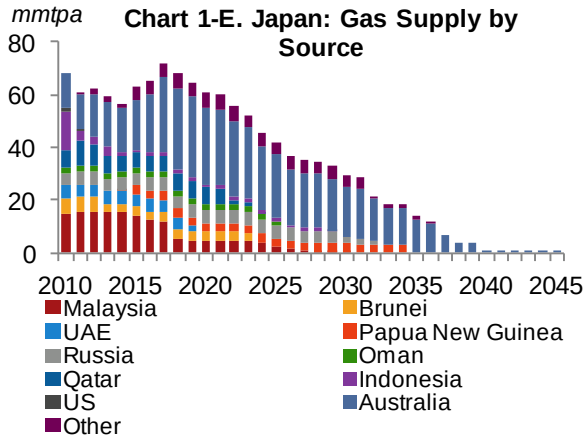
Forecast. Gas demand will depend heavily on Japan's revised nuclear policy, which has yet to be released. To replace declining electricity generation from the gradual phase-out of nuclear plants, Japan is expected to turn largely to gas-fired generation and also somewhat to oil- and coal-fired generation in the medium term. In the longer term, Japan aims to boost the share of renewables in the power sector.[9] Given these assumptions, gas is projected to grow by 1.4% p.a. to 2030 and will make up an increasing share of the fuel mix. Gas demand in power generation, the largest gas user, is forecasted to grow by 1.6%.Gas demand growth will also come from the industrial, residential, commercial, and non-energy use sectors as incremental penetration of gas is expected to continue. Beyond 2030, gas demand growth in the industrial, residential, and commercial sectors is forecasted to be minimal.

[9] *The Ministry of Economy, Trade, and Industry aims by expand installed capacity for photovoltaic and wind power, while additional hydro and geothermal power is restricted by available resources.*

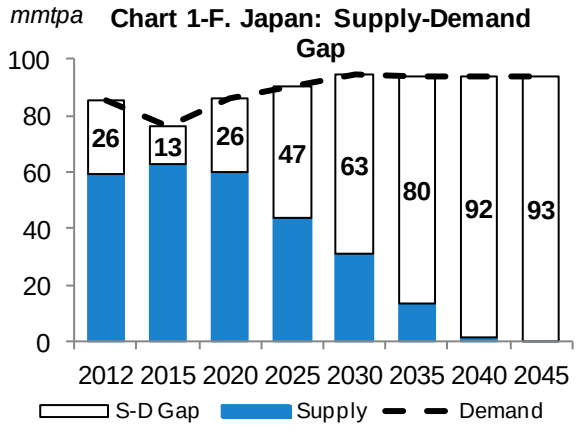




Natural Gas Supply. Japan's large volume of contracted LNG in 2010 allowed it to meet almost all of its gas supply needs; it only turned to the spot market for small volumes. This changed in 2011, when contracted LNG volumes fell and gas demand surged in power to make up for lost nuclear generation. Based on existing agreements, contracted LNG will peak in 2017 and then will slowly decline through the forecast period due as 15- to 20-year contracts expire. In 2020, contracted LNG volumes will total 61 mmtpa, similar to 2010 volumes. By 2025, contracted LNG volumes fall to 42 mmtpa and by 2030, decline to 30 mmtpa. In the next five years, Indonesia and Malaysia will quickly fall off as primary LNG suppliers due to expiring LNG contracts and Japan's LNG supply will become further diversified. Based on existing contracts, Papua New Guinea will be added as a supplier in 2015. Australian volumes will begin to ramp up through 2018, after which time they slowly decline. This is primarily due to expiration of contracts with the North West Shelf LNG, which may be constrained in extending all of its LNG contracts post 2020-2025 due to declining gas feedstock.



Supply-Demand Gap. The gap between LNG supply and demand in Japan is highly dependent on how quickly and to what extent nuclear power plants are restarted or permanently taken offline. In 2012, gas demand is projected to be even higher than in 2011 as all of the operational nuclear plants were offline for maintenance and inspections as of May 2012. By 2015, PFC Energy forecasts that some of this nuclear power will be back online after safety inspections are completed, causing a decline in gas demand from 2012 to 2015 (Chart 1-F). By 2020, PFC Energy forecasts that the supply-demand gap will reach 26 mmtpa, due to growing gas demand and declining contracted LNG volumes. By 2025, the supply-demand gap reaches 47 mmtpa, and by 2030, it will be 63 mmtpa. In the 2030 to 2045 forecast period, gas demand is projected to grow at <1% annually, assuming that Japan decides to keep some of its nuclear power plants online. Any further declines in nuclear generation through 2045 provide additional upside for gas demand.



South Korea

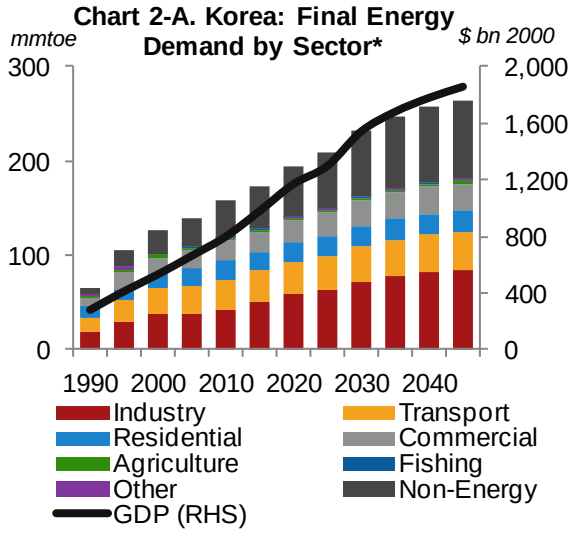
Summary. Similar to Japan, South Korea is a large and growing LNG importer. The country's gas demand is projected to rise by 2.3% p.a. through 2030. Driving this growth is incremental penetration of gas in the energy mix of the industrial, distribution, and power sectors. In the long term, LNG demand prospects depend on how quickly Korea installs nuclear and renewable generation capacity. In PFC Energy's forecast, the power sector continues to consume more gas even with substantial growth in nuclear capacity. Lacking domestic production, Korea will remain reliant on LNG for its gas supply. For the next few years, the country has secured enough contracted LNG to meet nearly all of its projected demand. By 2020, however, PFC Energy expects a supply-demand gap of 7 mmtpa, widening to 18 mmtpa by 2025. From 2030 to 2045, energy efficiency policies will limit growth of energy and gas demand.

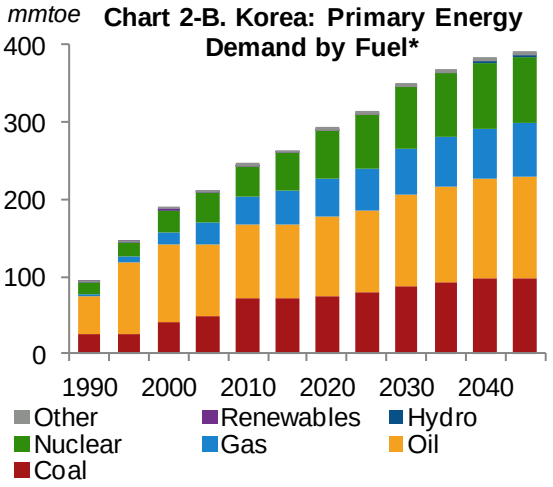
Energy Demand by Sector and by Fuel

Historical Trends by Sector. South Korea's primary energy demand rose by 7.3% p.a. from 1990 to 2000, but average annual growth slowed to just 2.7% from 2000 to 2010 due to slower GDP growth and declining energy intensity (Chart 2-A). The non-energy sector, which utilizes oil as feedstock to produce petrochemicals, has had the fastest growth in energy demand. The industrial sector also experienced fast-paced energy demand growth of 9.5% p.a. since 1990.

Forecasted Final Energy by Sector.[10] PFC Energy forecasts that final energy demand will grow by 2.1% p.a. through 2030, slower than historical growth due to South Korea's energy efficiency policies. Within the next two decades, the non-energy (petrochemicals) sector is forecasted to have the fastest growth (3.1% p.a.). Industrial energy demand is forecasted to grow by 2.8% p.a. while energy demand in the power sector is forecasted to grow by 1.8% p.a. due to electricity usage in the industrial and commercial sectors.

Forecasted Primary Energy by Fuel. Two decades ago, South Korea relied nearly entirely on oil, coal, and nuclear; gas made up 3% of the fuel mix and was only used in the power and residential sectors (Chart 2-B). The country has since become more gas-reliant: gas' share in the fuel mix is now 15% and the share of oil is down to 38% from 53% in 2000. Fuel switching away from oil has been economy-wide, as the power, industrial, and distribution sectors have increasingly relied upon gas and/or electricity for their energy needs. PFC Energy expects this trend away from oil to continue and forecasts that oil's share in the fuel mix will fall to 34% by 2030 and gas' share will rise to

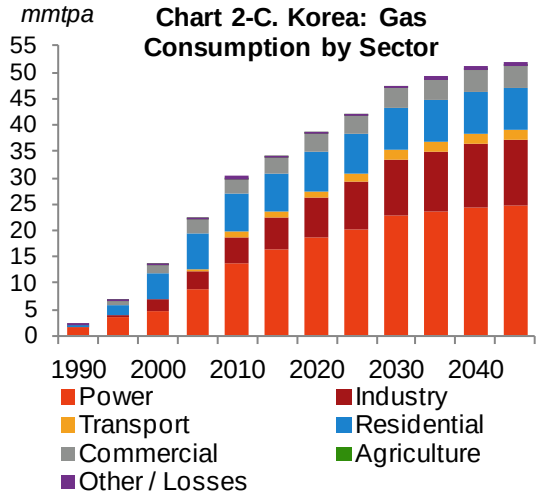




[10] **Note: The difference between primary energy demand and final energy demand is mainly due to thermal efficiency losses and also includes energy industry own-use and other discrepancies.*

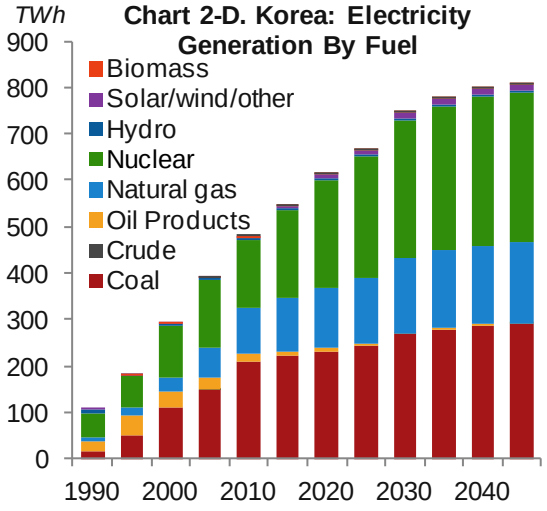
17%. Coal will maintain its average historical share of 25% in the fuel mix, while nuclear power's share will reach 22%, assuming Korea brings online its long queue of nuclear power plant additions. Post 2030, PFC Energy has assumed little change in the fuel mix.

Natural Gas Demand Forecast by Sector



Historical. In 2011, Korean LNG imports stood at 35.8 mmtpa, up 4.4% over 2010. Lacking meaningful levels of domestic gas production, Korea began importing LNG in 1986. From 1990 through 2000, demand for gas grew by 20% p.a.—faster than any other fuel. Gas demand growth slowed to 7% p.a. from 2000 to 2010. Power has been the primary driver of growth in gas demand, followed by the residential and industrial sectors.

Forecast. Gas demand is forecasted to increase by 2.3% p.a. through 2030, due largely to demand from the power, residential and industrial sectors. PFC Energy forecasts gas demand in industry will rise by 4.1% p.a. through 2030. Within the industrial fuel mix, gas has been displacing oil—a trend which is expected to continue. In the residential sector, gas is expected to hold steady in its share of the energy mix at 44%, growing in line with total residential energy demand. Gas demand in the power sector is forecasted to grow by 2.5% annually and will be limited by Korea's aggressive build out plans for nuclear power plants. In early 2012, 2 GW (Gigawatts) of capacity was brought online and 3.8 GW are under construction. KEPCO aims to build another 11 GW of nuclear capacity between 2017 and 2024. Similar to its program for nuclear power, Korea intends to greatly boost electricity generated by renewable sources. In the longer term, Korea hopes to be the third-largest nuclear power generator in the world, behind the US and France[11].



Given these nuclear and renewable energy policies, and the forecasted constant share of coal in the fuel mix, there is limited scope for a larger role for gas in the power mix beyond its current 20% share. At the same time, any delays in the nuclear and renewable energy programs will provide an upside for gas demand in power. Through 2045, industry and power are expected to continue to have the largest gas demand. In this longer-term period, gas demand is projected to rise by ~1% p.a., a slowdown compared to the 2010 to 2030 period due to several assumptions. By 2030, PFC Energy forecasts that Korea's fuel mix will be less variable, meaning there will be less incremental penetration of gas and less displacement of other fuels. Also, PFC Energy has factored in further gains in energy efficiency in the economy which will suppress energy demand.

[11] *Prior to the nuclear crisis in Japan, Korea was the fifth-largest generator of nuclear power and would need to surpass Japan and Russia to become the third-largest generator.*

Natural Gas Supply. With domestic production projected to peak at 0.4 mmtpa before 2015, Korea will continue to rely on LNG to meet gas demand. KOGAS, the principal importer, has a diversified LNG supply portfolio, with no less than eight countries under contract to supply the market in 2011 (Chart 2-E). Contracted LNG peaks in 2017 and 2018 when the US is added as a supplier.[12] KOGAS is responsible for 96% of the contracted LNG volumes. Due to the 15- to 20-year terms of signed contracts, LNG supply begins to sharply decline from 2025 onwards. None of Korea's existing supply agreements extend past 2036.

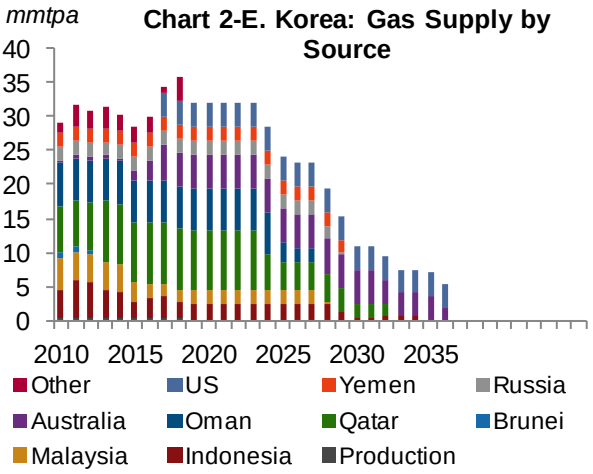


Chart 2-E. Korea: Gas Supply by Source

Supply-Demand Gap. Through the next decade, Korea has contracted supply for upwards of 80% of its projected demand. By 2020, Korea will face an LNG supply-demand gap of 7 mmtpa, though this widens quickly to 18 mmtpa by 2025 due to lower contracted LNG and higher import needs. By 2030, contracted volumes fall well short of the forecasted demand, creating a gap of 37 mmtpa. PFC Energy projects that Korea's LNG import needs may exceed 50 mmtpa by 2045. Korea is well-positioned to receive incremental cargoes to meet LNG demand in the short and medium terms. The country has four existing LNG receiving terminals: KOGAS' Pyeongtaek, Incheon, and Tongyeong terminals and POSCO's Gwangyang terminal. KOGAS hopes to bring online a fifth LNG terminal by 2015. Another terminal proposed by GS Caltex, Boryeong, is delayed and no recent announcements have been made for its development timeline.[13]

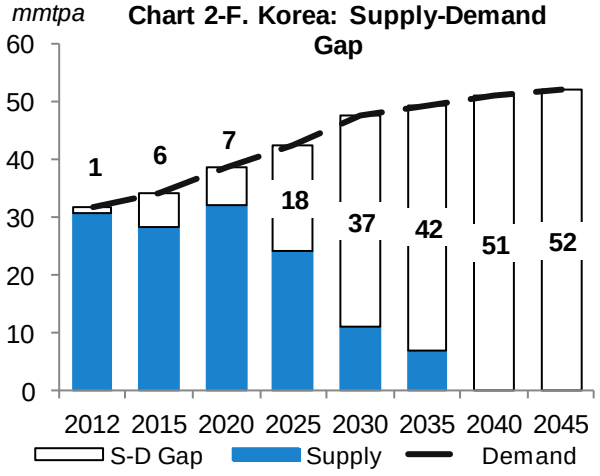


Chart 2-F. Korea: Supply-Demand Gap

[12] *KOGAS has agreed to offtake LNG from Sabine Pass LNG for 20 years.*

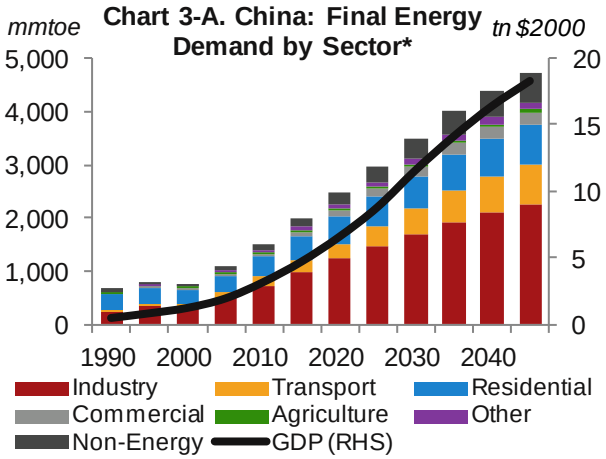
[13] *Chevron, which has a 50% stake in the proposed terminal, has indicated that it would hold off on Boryeong until it was certain that it could sell regasified LNG into the local market. South Korea's regulatory framework gives KOGAS a monopoly on LNG imports, though the law was relaxed to allow companies to import LNG for captive use only.*

China

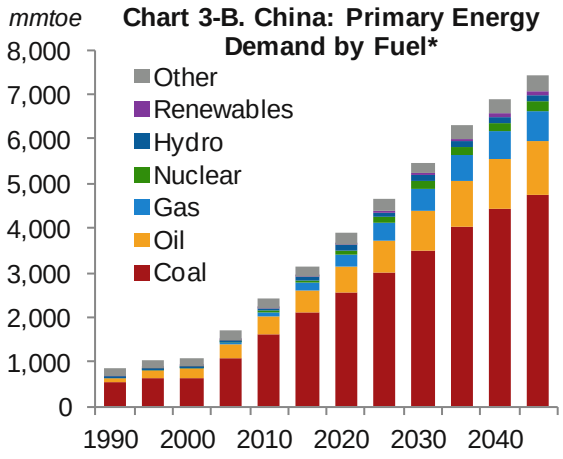
Summary. China is forecasted to have strong growth in gas demand across all sectors, bolstered by policies to increase gas' share in the fuel mix. China aims to boost LNG imports, as well as pipeline imports and production, and has proposed a large number of LNG import terminals. In the near term, PFC Energy expects that domestic production, contracted pipeline and LNG imports will largely be able to meet gas demand. In 2020, PFC Energy forecasts that China will face a supply-demand gap of 17 mmtpa, which will increase to 47 mmtpa by 2025 due to fast-paced demand growth. After this point, the gas supply-demand gap widens due to declining production and lower contracted gas volumes.

Energy Demand by Sector and by Fuel

Historical Trends by Sector. Primary energy demand growth has been fast-paced in China, rising 8% p.a. since 2000 on the back of ~10% average GDP growth (Chart 3-A). The industrial sector, the largest energy-consumer, had demand growth of 9.4% p.a. while energy demand in the commercial sector, the other economic driver, grew by ~10% p.a. Residential energy demand grew slower, by 2.7% p.a., while the transport sector had robust growth of 7.6% p.a. Energy intensity has been declining in the industrial and commercial sectors while energy per capita has been growing in the residential and transport sectors.



Forecasted Final Energy by Sector. Final energy demand is forecasted to rise by 4.3% p.a. through 2030, against 6.7% average annual GDP growth and 0.3% population growth (Chart 3-B).[14] Trends in reducing energy intensity will persist: energy demand per capita in the residential and transport sector will increase, while the commercial and industrial sectors will become more energy efficient. Based on these trends, PFC Energy forecasts the transportation and residential sectors will have strong energy demand growth through 2030, rising annually by 5.5% and 2.8% p.a., respectively. Demand will rise by 4.4% p.a. in the industrial sector and by 5.2% p.a. in the commercial sector. From 2030 to 2045, slower forecasted GDP growth will lead to slower energy demand growth across all sectors. By this time, China is expected to have made large gains in energy efficiency, limiting growth of final energy demand to 2% p.a. from 2030 to 2045.



Forecasted Primary Energy by Fuel. Since 2000, China has been relying more heavily on coal and gas and less on oil and other (geothermal and biofuels/waste) to meet growing energy demand.

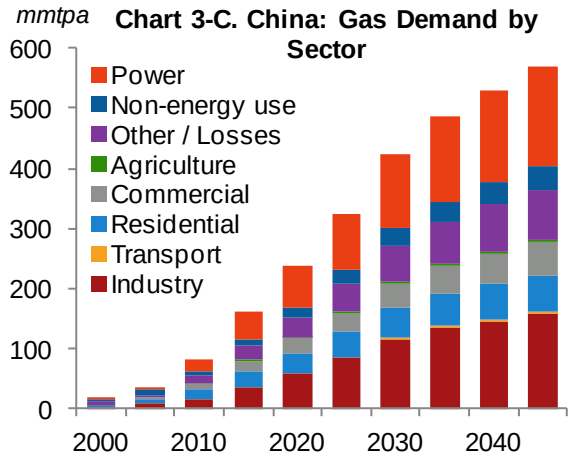
[14] Source: UN PP (United Nations Population Prospects)
**Note: The difference between primary energy demand and final energy demand is mainly due to thermal efficiency losses and also includes energy industry own-use and other discrepancies.*

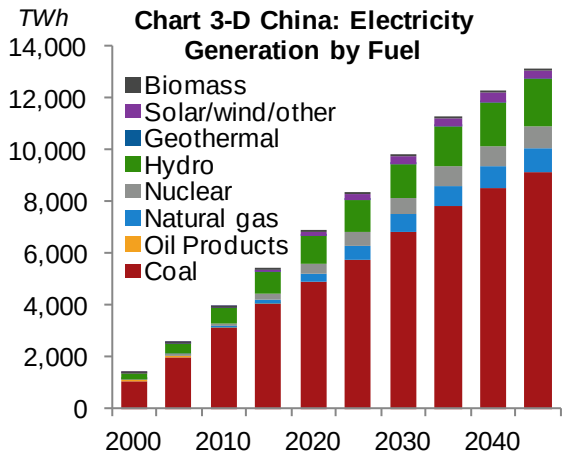
Going forward, coal, oil and biomass (other fuels) are projected to decline in their share of the fuel mix as China relies more heavily on natural gas, nuclear, and non-biomass renewables such as wind and solar to power its economy.

Natural Gas Demand by Sector

Historical. In 2011, gas demand in China was ~99 mmtpa and accounted for ~4% of the national fuel mix. Gas has long been consumed in almost every sector in China and its share in the fuel mix has increased over time. The power and residential sectors are the largest gas consumers, followed by the industrial and the commercial sectors. The power sector has only recently become a major source of gas demand, as coal and hydro have been favored historically in electricity generation thanks to ample domestic supply. Coal makes up almost 80% of electricity generation and hydro accounts for another 17%, its power output having more than doubled in the past ten years. Natural gas makes up less than 2% of power generation. Other than renewables, gas has been the fastest growing source of electricity generation, with 27% p.a. growth since 2000. Outside the power sector, gas has increasingly been favored over other fuels, causing total gas demand to grow by 16% p.a. since 2000—faster than demand for both coal and oil.

Forecast. Through 2030, PFC Energy forecasts gas demand will increase by 9% p.a., bolstered by policies to boost gas' share in the fuel mix. The power sector will have the greatest growth in demand, by 4.4% p.a., followed by the industrial and transport sectors. Nuclear and renewable energy sources are forecasted to contribute to a larger share of electricity generation while the reliance on oil will decline. After 2030, gas demand is forecasted to grow in line with primary energy demand, by 2% p.a. Greater usage of renewable energy and declines in energy intensity will also bring down gas demand.



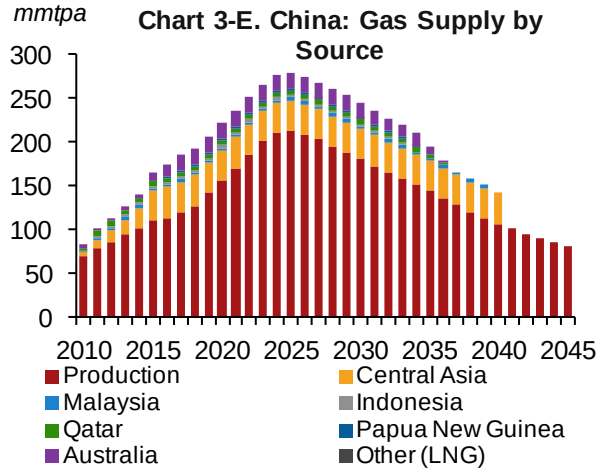


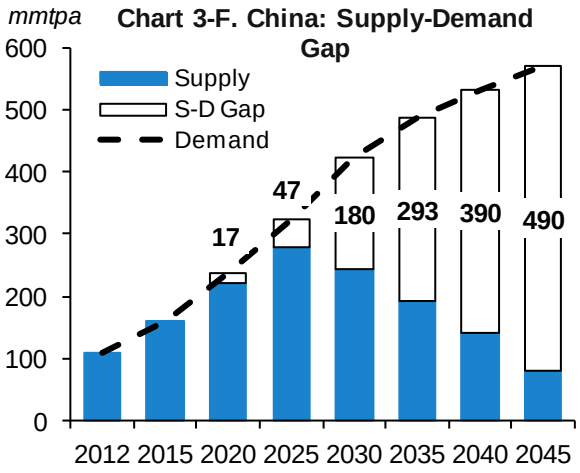
Natural Gas Supply. China has been working to diversify its gas supply sources and aims to substantially boost domestic production on top of LNG and pipeline imports. Based on currently identified reserves and exploration estimates at the P50 level, PFC Energy has modeled domestic gas production to increase by over 7% p.a. through 2025.[15] China has contracted to receive 34 mmtpa (50 bcm) of gas pipeline imports from Central Asia through 2040, though this likely will be extended longer. In terms of LNG, Australian projects will likely be the largest suppliers. Chinese buyers have signed agreements to offtake volumes of ~18 mmtpa by 2017, and are currently under contract to offtake Australian LNG until

[15] *This reflects PFC Energy's P-50 scenario production outlook, which includes production from CBM and shale gas.*

2036. China has an aggressive expansion policy for its LNG import terminal infrastructure: based on announced projects, LNG import capacity could more than triple by the end of the decade from its current capacity of ~19 mmtpa.

Supply-Demand Gap. Due to its various gas import contracts and expanding domestic production, China is well-supplied through the latter half of the decade. Even as contracted supply and production increase through the 2025 timeframe, by 2020, demand is predicted to outstrip supply, creating a 17 mmtpa gas supply-demand gap (Chart 3-F). By 2025, PFC Energy forecasts China will face a supply-demand gap of 47 mmtpa. While PFC Energy forecasts declining domestic production after 2025, there is a large upside for gas production in China if the P10 scenario is assumed for the exploration reserves outlook, though this additional production will not completely eliminate the supply-demand gap from 2020 onwards.[16] Also, if China can greatly ramp-up shale gas production, this could provide further upside to the domestic supply figure, however, significant technological and other hurdles need to be overcome before the country sees material production from its shale gas resources.[17] What is more, a higher-than expected production outcome from shale gas would likely, at first at least, just translate into higher gas consumption rather than a displacement of gas imports. Since the appetite for gas in China is very high and gas penetration levels are still very low, the market would be able to absorb additional gas supply from domestic production without lessening the demand for LNG imports.

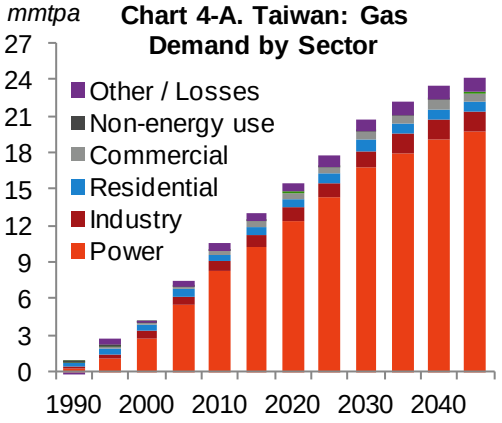




[16] *If the P-10 scenario is assumed, this boosts domestic production (and in turn reduces the supply-demand gap) by 11 mmtpa in 2020 and 13 mmtpa in 2025. Even assuming the P-10 scenario, there is a 6 mmtpa supply-demand gap in 2020 and a 34 mmtpa gap in 2025.*

[17] *Shell is among the international oil and gas companies interested in developing China's shale gas sector and signed a production-sharing agreement for shale gas acreage with CNPC in March 2012.*

Overview of Other Asian LNG Regions: Taiwan

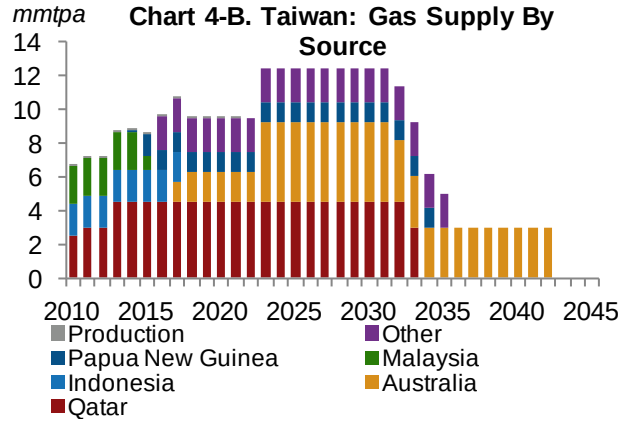


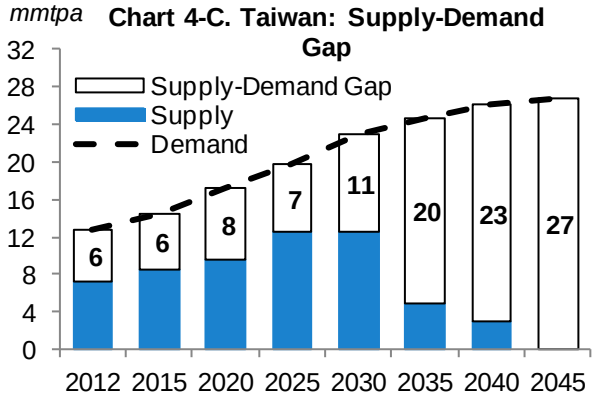
Gas Demand. Taiwan has experienced fast-paced gas demand growth, by 17% p.a. from 1990 to 2000 and by 10% p.a. from 2000 to 2010 (Chart 4-A). By 2011, Taiwan's LNG imports reached 12.2 mmtpa. The power sector accounts for over three-quarters of gas demand. Gas-fired generation has grown in its share of power from 10% in 2000 to 23% in 2010. Demand growth has also been strong in the industrial, residential and commercial sectors, though combined, these sectors account for just 17% of demand.

PFC Energy forecasts gas demand will double by 2030, rising by 3.5% p.a. Power will continue to account for the largest share of gas demand by far, with growth of 4.6% p.a. Within the power sector, gas is forecasted to account for a larger share of the fuel mix (30%) by 2030, displacing the use of oil. As nuclear power plants are taken offline, greater space for additional gas-fired power is expected to be created from 2020 to 2030.[18] Still, there is some uncertainty over the extension of nuclear power plants, in turn creating uncertainty for gas use in power. Renewables are forecasted to replace nuclear and oil in the fuel mix, though will not impact gas demand in power. From 2030 to 2045, total gas demand growth will slow to 1.1% p.a., largely due to lower expected electricity generation needs. The industrial sector, the main power consumer, is expected to continue making energy efficiency gains, while population declines will limit electricity demand from the residential and transport sectors.[19] In addition, by 2030, the increasing penetration of gas in the fuel mix is expected to have leveled off once gas' share reaches 15%.

Supply-Demand Gap: Based on existing contracts, Qatar and Australia will be Taiwan's main LNG suppliers through 2040 (Chart 4-B). As LNG contracts with Malaysia and Indonesia expire, contracts with PNG LNG and Shell (graphed as "other") start up. In total, Taiwan has secured long-term LNG contracts for between 55% and 65% of gas demand, leaving space for additional suppliers to send LNG to Taiwan. Taiwan's LNG supply-demand gap is projected to be 7-8 mmtpa from 2020 to 2025 and 11 mmtpa by 2030 (Chart 4-C). By 2045, PFC Energy projects that demand could reach 27 mmtpa.

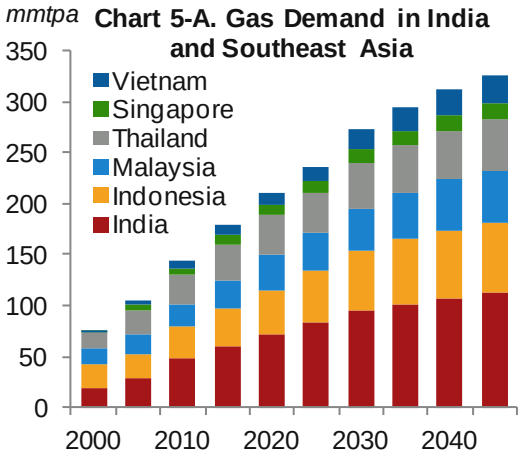
[18] *The power forecast assumes that the proposed Lungmen nuclear plant is built, though if it is delayed, this creates upside for gas.*
[19] *Taiwan's Council for Economic Planning and Development forecasts that population will decline by 0.5% p.a. from 2030 to 2045.*





Overview of Other Asian LNG Regions: India and Southeast Asia

Natural Gas Demand



Historical. In 2010, gas demand in India and Southeast Asia (Vietnam, Indonesia, Singapore, Thailand, and Malaysia) stood at ~144 mmtpa (19 bcf/d, or billion cubic feet per day), representing growth of 6.5% p.a. since 2000 (Chart 5-A). Trends in gas demand growth vary greatly by country. Indonesia was once the largest gas consumer in the group but was surpassed by India thanks to its gas demand growth of 9.2% p.a. Thailand has also had rapid demand growth of over 7% p.a. since 2000. The smallest gas-consuming countries have had the fastest growth in demand: Vietnam's gas demand has risen by nearly 20% p.a. and Singapore's demand by 19% p.a. in the past decade.

Forecasted. Together, India and Southeast Asia are forecasted to have 3.9% p.a. growth in gas demand through 2030, lifting gas demand to 295 mmtpa (40 bcf/d) by 2035 and 325 mmtpa (~50 bcf/d) by 2045. India and Vietnam are forecasted to have the highest growth, at a rate of 5%, bolstered by demand in the power and industrial sectors. In Vietnam, gas is also important as feedstock in fertilizer production and in Thailand and Malaysia, the transport sector is an

important source of gas demand growth. For several countries in the region, gas will compete with coal, which is being developed to boost electricity generation.

Supply-Demand Gap

These six Asia-Pacific LNG regions have distinct strategies and challenges to supply their expanding domestic gas markets. Singapore and Thailand will need LNG imports to meet demand growth, the extent of which will also depend on pipeline flows into these countries. India and Vietnam have the potential to be well-supplied going forward if each can achieve adequate domestic gas production. In the case of Malaysia and Indonesia, two LNG exporters who are set to also become importers, there is much greater uncertainty in the projected supply-demand gap due to the each market's regional imbalances, the level of future LNG exports, and the ability to bring gas supply to demand centers.

Singapore and Thailand. Singapore is the smallest region in the group and has one under-construction regasification terminal which will allow the city-state to import up to 6 mmtpa of LNG by Q1 2014. It has one existing LNG contract with BG for 3 mmtpa. Singapore currently relies on pipeline gas imported from Malaysia and Indonesia, but is diversifying its gas supply should piped gas decline in the future. PFC Energy projects Singapore will have a minor supply-demand gap by 2020 (assuming pipeline imports continue), but will need additional LNG imports by 2025. In Thailand, growing gas demand is met by three sources: domestic production, pipeline imports from Myanmar, and recently, LNG imports. The country brought online ~5 mmtpa of regasification capacity, which if utilized, will eliminate any potential supply-demand from 2020 to 2030. Thailand has not signed any LNG import contracts, making this a potential destination for LNG Canada's gas.

India and Vietnam. Domestic production, which makes up the majority of India's gas supply, has fallen short of levels needed to meet rising gas demand, causing India to turn to LNG imports. Production levels have been impacted by premature declines from the D-6 field as well as uncertainty around gas pricing and industry regulation. PFC Energy's P-50 production scenario for India forecasts growth through 2025 and then a sharp decline – this scenario, however, hinges on India reforming domestic pricing in order for this production outlook to materialize.

In terms of LNG imports, Qatar has historically been India's primary supplier, supplemented by spot purchases, though GAIL (Gas Authority of India Ltd.) will begin importing 3.5 mmtpa from Sabine Pass LNG in the U.S. This, combined with Petronet's 6 mmtpa Gorgon LNG off-take, provides India with 20 mmtpa of contracted LNG volumes from 2018 through 2028. India has two existing regasification terminals, another two terminals under construction, and multiple additional proposals. A lower ability to pay has acted as an impediment to the procurement of new LNG contracts. If India can boost its gas production, which remains to be seen, then the country will be fairly well-supplied through 2025 when taking into account these LNG contracts.[20] If these production volumes are not realized, India will increasingly need to turn to LNG to meet demand.

Vietnam's strong projected growth in gas demand will quickly lead to a widening supply-demand gap unless the country can boost domestic production at a faster pace or rely more heavily on LNG imports. The country aims to bring online two proposed LNG import terminals by 2015, which would together provide 3 mmtpa of regasification capacity, though PFC Energy expects some development delay on both of these projects as they are not yet under construction.

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[20] *Growth in domestic production is subject to pricing changes which would provide incentives to boost production. In India, domestically produced gas prices are regulated by an administered price mechanism which holds the wellhead price at $4.20/MMBtu or by PSCs which also hold prices flat.*

Malaysia and Indonesia. Malaysia and Indonesia face similar challenges in meeting rising gas demand: both have regional supply-demand imbalances and both are LNG exporters that are constructing regasification terminals. As such, their LNG import needs will depend on geography and production. While they have, in aggregate, large reserves, those reserves may not be close to population centers where demand is located. As a result, these countries are constructing regasification terminals to either import LNG or to carry LNG produced elsewhere in their own countries to market. Secondly, as in many countries, production can be delayed due to a number of technical and commercial reasons. In other words, the production forecasts are sensitive to potential supply shortfalls that would widen the wedge that needs to be met by LNG.

Assessment of Competing LNG Sources: Pacific Basin

Between 2007 and 2011, buyers in the Asia-Pacific received 57% of their LNG supply from liquefaction projects located in the Pacific Basin. The next largest source of LNG supply was the MENA (Middle East and North Africa) region, which contributed 35% of Asia-Pacific's volumes during the same period. Looking forward, PFC Energy expects the Pacific Basin to provide the vast majority of new source LNG supply available to buyers in the Asia-Pacific region. By contrast, PFC Energy does not expect an equivalent increase in new supply from the MENA region, causing MENA's share of global LNG supply to decline. Consequently, future Pacific Basin projects either under-construction or proposed are the most relevant when assessing LNG Canada's competitive landscape. Existing LNG projects are less relevant than upcoming LNG projects, given that Pacific Basin projects have signed a majority of their capacity to long-term contracts. Also, PFC Energy expects that of the Pacific Basin contracts which are set to expire before 2020, only a share will be extended to the 2020-2030 period.

In 2011, the Pacific Basin had 101 mmtpa of liquefaction capacity online, the majority of which was from projects located in Australia, Indonesia and Malaysia. There are a number of proposed projects under development aimed to grow this capacity. If all these announced projects moved forward according to their proposed timelines, liquefaction capacity in the Pacific Basin would reach 284 mmtpa in 2020 and 310 mmtpa in 2025– which could dwarf available demand. However, proposed projects frequently become delayed or stalled if they are faced with too many development challenges, which range from geopolitical risk to lack of secured feedstock.[21] Given that the slate of announced projects faces a variety of risks, PFC Energy does not believe that all of this proposed capacity will move forward according to their announced timeframes.

Review of Main Risks by Country/Sub-Region in the Pacific Basin

Organized by country, the following table identifies some of the main risks faced by existing or proposed projects in the Pacific Basin.

Table 1. Main Risks Facing LNG Projects by Country

Country	Main Risks
Australia (Eastern / CBM)	▪ Cost inflation for materials and labor is causing higher EPC costs and delays ▪ The particular combination of multiple LNG projects simultaneously under construction and strong demand from other extractive industries operating in the region has added significant tightness to the labor market ▪ The government's current carbon tax legislation will impact project economics to an extent, though not enough to block project development ▪ Environmental regulations over water extraction could delay projects ▪ Companies still need to prove up reserves to justify plans for brownfield expansions ▪ Unclear how the production / ramp-up process will impact feedstock reliability ▪ CBM contains virtually no liquids content, thus the project will not see upside from liquids revenues
Australia (Western)	▪ Cost inflation for materials and labor is causing higher EPC costs and delays ▪ The particular combination of multiple LNG projects simultaneously under

[21] *PFC Energy applies distinct classifications for projects that are "delayed" versus "stalled". A delayed project is one that faces specific obstacles to reaching FID or its original announced start date. While PFC Energy considers these obstacles as surmountable, they will nevertheless require a postponement of the anticipated FID date or start date. By contrast, a stalled project faces sufficiently severe obstacles that require the project's anticipated FID date or start date to be indefinitely postponed.*

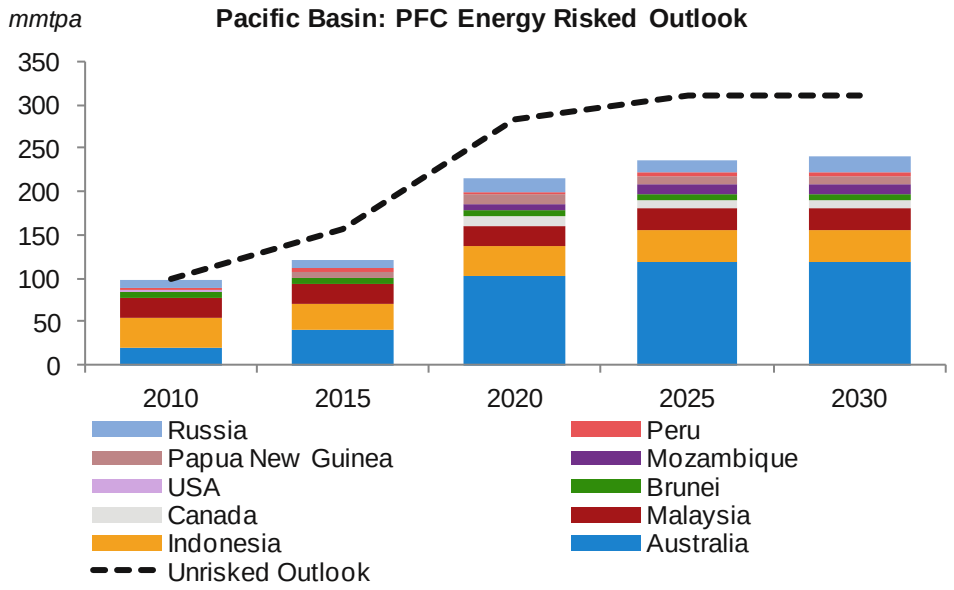
	construction and strong demand from other extractive industries operating in the region has added significant tightness to the labor market ▪ The government's current carbon tax legislation will impact project economics to an extent, though not enough to block project development ▪ The fact that multiple IOCs are involved in multiple projects in the region offers the potential for partner drag issues; IOC projects in Western Australia will compete for company resources against each other and also with projects in other parts of the world
Brunei	▪ Brunei recently renewed its original long-term contracts with Japanese utilities, but for lower volumes and over a 10-year duration only ▪ The largest constraint to future LNG production is a gas supply risk. In the medium-term, upstream co-venturers will need to prove-up new reserves and develop new gas projects to increase volumes and contract periods ▪ If available proved reserves are insufficient to support liquefaction capacity, under-utilization of existing capacity will ensue
Canada	▪ Permitting and constructing a pipeline from the wellhead to the port will take time, although it is unlikely to be a project blocker ▪ British Columbia's current carbon tax legislation will impact project economics
Indonesia	▪ The government's preference to satisfy growing domestic gas needs has threatened the longevity of existing projects and the viability of new ones
Mozambique	▪ Large infrastructure development will put a stress on infrastructure and government institutions ▪ Need for bigger players and gas field unitization could delay LNG projects
Malaysia	▪ Malaysia's new projects are often farther removed from existing infrastructure ▪ Sustaining and growing volumes will depend on exploration success.
Papua New Guinea	▪ Limited established infrastructure and difficult physical conditions will challenge project developers ▪ Social unrest, landowners issues and disagreements over revenue-sharing pose key political risks
Peru	▪ The government is anxious to satisfy domestic demand and current plant may not be utilized fully ▪ The government has made announcements that it intends to reallocate reserves currently feeding the Peru LNG project to the domestic market
Russia	▪ Large-scale projects and harsh operating conditions make project execution a challenge for Russian projects ▪ The commercial priorities of Gazprom and the Russian state are uncertain
US (Alaska)	▪ Kenai LNG was expected to close in 2011, but has extended its export license through March 2013. It is uncertain whether this license can be renewed beyond 2013 ▪ While multiple IOCs have agreed with the State of Alaska on the development of gas resources located in the North Slope starting in 2015-16. A decision on how the gas will be commercialized has yet to be made. Exporting LNG, one of the options being considered, would require a substantial pipeline investment to a greenfield LNG plant.

Risked Outlook for Liquefaction Capacity in the Pacific Basin

Taking this selection of risks into account, PFC Energy has forecasted a risked outlook for proposed

projects in the Pacific Basin, and expects a total of 218 mmtpa of liquefaction capacity to be online by 2020 and 236 mmtpa online by 2025 not including the LNG Canada Project.[22]

- Of the 218 mmtpa of capacity expected in 2020, the largest contributors of new capacity since 2010 will be Australia (+81.7 mmtpa), Canada (+10.0 mmtpa, not including the LNG Canada Project), Papua New Guinea (+9.9 mmtpa), Mozambique (+7.5 mmtpa) and Russia (+4.8 mmtpa).
- Of the additional 18 mmtpa of capacity that is expected to be added between 2020 and 2025, the main contributors will be Australia (+16.0 mmtpa), Indonesia (+3.0 mmtpa) and Mozambique (+2.0 mmtpa). Malaysia is expected to lose 4.0 mmtpa.
- Canada's share of Pacific Basin export capacity, excluding LNG Canada, is projected to reach 5% of total capacity in 2020 and 4% in 2025.



The majority of new capacity expected online by 2020 has already been tied by long-term LNG contracts to buyers in Japan, Korea, China and the rest of Asia. In other words, there are a limited number of new liquefaction projects which have not yet contracted out a large share of their LNG capacity. Furthermore, LNG buyers may be unable to extend all of their current Pacific Basin supply contracts through 2020-2030. Those due to expire before 2020 include contracts with North West Shelf LNG (Australia), Tangguh (Indonesia), and Malaysia LNG. Amounting to volumes of 19 mmtpa, PFC Energy expects that only a share of these existing contracts will be extended at their current levels through the 2020 to 2030 timeframe. This provides opportunities for the LNG Canada Project, as LNG buyers will only have a handful of new projects from which to source LNG supply in the Pacific Basin to meet their growing gas supply-demand gaps described above. In addition, given that LNG Canada faces lower risks than projects located in other region, the Project offers various advantages to prospective buyers. These include Canada's low political and operational risk, higher domestic supply compared to domestic gas demand growth, developed infrastructure, access to gas market hubs, and strong institutional capacity compared to other regions such as Papua New Guinea, Indonesia, Malaysia, and Mozambique.

[22] *To determine the risked outlook for LNG capacity, PFC Energy considers different risk categories to determine when and if every proposed LNG project will move forward.*

The Competitiveness of LNG Canada

Although gas is an increasingly global commodity, there is still no "global" gas market. Value is set by microeconomic and regional factors rather than macroeconomic and global ones. In particular, location, contract structure and timing are more influential in determining value than the global supply and demand balances. In fact, gas prices across and even within regions have widely diverged in recent years.

At the current time, gas pricing can be broadly classified into four categories, although there are several instances around the world where gas pricing combines one or more of these categories:

- **Hub-based systems:** Supply and demand set prices at liquid hubs. In North America, the most important price marker is Henry Hub (Louisiana). Other prices in North America trade at a premium or discount to Henry Hub.
- **Oil-linked systems:** In several regions outside North America, gas is traded under long-term contracts whose price is linked to oil.
- **Regulated systems:** In many parts of the world the government sets wellhead, transportation and end-user prices.
- **Subsidized systems:** In several countries in the Middle East and North Africa, gas prices barely suffice to cover production costs.

Most LNG contracts in Asia-Pacific are crude-based with reference to the Japan Customs Cleared Price (JCC), although there is a growing desire to explore alternative pricing mechanisms. This is the average price of crude into Japan, which is published by the Petroleum Association of Japan (PAJ). Although two contracts can be linked to the same underlying components, the end price may be very different depending on factors used in establishing the price of LNG. Contracting long-term LNG volumes from Western Canada offers a number of important advantages to the procurement portfolios of prospective buyers, detailed below.

- **Canada is an important new source of LNG supply:** Between 2001 and 2011, global LNG production capacity grew by 216 mmtpa, as six new countries started to export LNG.[23] Yet more than a quarter of that growth came from one country alone (Qatar), and of the 12 countries that were exporting LNG in 2001, only 6 expanded their capacity – the rest were either flat or declined. To expand, the LNG market has depended heavily on new exporters to enter the LNG marketplace, especially large suppliers such as Qatar in the 2000s and now Australia in the 2010s.

  LNG exports from Western Canada thus offer an important source of supply growth. Between 2000 and 2010, the combined LNG production of the Middle East and Atlantic Basins more than tripled. During the current decade and at the beginning of the next decade, the combined growth of these regions will be marginal by comparison. In this context, exports from Canada are critical to ensure that the global LNG market keeps growing.

- **Canada offers portfolio diversification and thus enhances energy security:** Diversification is the most durable and tested criterion for achieving national energy security objectives. In Asia in particular, where most counties have limited or no access to alternative sources of natural gas supply via pipeline (as has Europe, for example) and where many countries also have limited domestic sources of energy, security has come through supply diversification. From a historical

[23] *The six new LNG exporting countries were: Egypt, Equatorial Guinea, Norway, Peru, Russia and Yemen.*

reliance on Southeast Asia (Brunei, Indonesia and Malaysia), Asian buyers then helped cultivate Qatar and later Australia as new LNG supply sources. The interest in developing new sources of supply is essential to meeting the desire of both LNG buyers and project developers to minimize the risks associated with a given project or source of supply in their portfolios.

The LNG Canada Project offers diversification in a number of ways. For one, it is quite simply a new source of LNG supply, which boosts diversification by definition. But its benefits extend well beyond that. The country is politically stable with low levels of political and operational risk. Canada has high institutional capacity to carry out major infrastructure projects and the risk to contract sanctity, which is a concern for several other LNG sources, is low. Canada also offers exposure to new upstream development, allowing further diversification. This does not mean that Canada is a risk-free environment – but it is certainly low-risk.

LNG from Canada will be particularly valuable for buyer portfolio diversification as the LNG industry turns heavily to Australia to meet LNG growth over the next decade. In PFC Energy's estimations, over 50% of the growth in global LNG supply from 2011-2020 will come from Australia. This fact means that the industry has a very large amount of exposure to Australia. Events in Australia can thus have a disproportionate impact on global LNG markets and on supply security from a buyer's perspective. In that environment, where so much growth comes from one country, developing new sources of supply will offer an additional benefit by reducing the exposure that buyers have to Australia.

- **Canada is well-positioned competitively:** Western Canada is proximate to some of the world's fastest growing LNG markets. It takes 8-10 days to ship LNG from the Kitimat Port to Japan versus 13-15 days to ship from Qatar, or 6-8 days from Australia. Canada is also well-positioned to take advantage of the low natural gas prices in North America (where natural gas is abundant). Developing new sources of supply from coal-bed methane has allowed Australia, for example, to propel itself as a premier source of LNG supply in the world.

  For over 5 years now, the LNG industry has recognized that the resource potential in North America likely exceeds the ability of the market to absorb gas. Yet the LNG industry has to this point not taken direct advantage of this new source of supply. The LNG Canada Project, in addition to other projects in the United States, will allow buyers and sellers to take advantage of the technological developments that have produced an energy revolution in North America.

LNG Business Models

The role LNG Canada will play in each of the Project Owners' LNG portfolios will largely be a function of each company's business model. Companies that operate in the gas and LNG industry generate value from gas in two ways:

- **Access to resources.** For many International Oil Companies (IOCs) and National Oil Companies (NOCs) with gas reserves, entry into the gas business as either a pipeline or LNG supplier was motivated by a desire to commercialize their production. For these players, the key motive driving participation in the gas value chain is production.

- **Access to markets.** Since gas is not a global commodity to the same extent as oil, finding a market is a necessary precondition for developing a gas commercialization plan. Being able to reach end-users in the residential, commercial, industrial and power sectors has been a key ingredient for unlocking the value of natural gas.

Historically, these two value propositions have been distinct: companies have created value from either their resource position or their access to markets. Few, if any companies, had a coherent strategy for doing both with the exception of producers who sold gas within the market in which it was produced. Conventional E&P companies – those with upstream assets – focused on producing gas and had less presence in the midstream and downstream segments of the value chain. By and large, this consisted of IOCs, NOCs and some independents. Similarly, gas and power utilities have naturally provided the key markets for consumption. The traditional relationship between upstream players and utilities was mutually beneficial: producers guaranteed supply to utilities, while utilities guarantee a market for producers.

This traditional value proposition landscape resulted in a particular set of terms for LNG contracts. In general, most contracts signed were for durations of 20 years, and also stipulated the exact market or regasification terminal to which offtake could be sent. Long-term, fixed-destination LNG contracts served the needs of both parties given their static access to either the resource or the market.

Over the last decade, this binary landscape for generating value has begun to evolve. For a variety of reasons, LNG players on either end of the value spectrum have looked to diversify their business models by increasing their involvement throughout the value chain.

Moving Upstream. Utilities are interested in moving upstream for at least one of three reasons: first, as value has moved upstream in recent years, they seek to capture it. Second, there is a strong incentive to develop an upstream position as a hedge for the downstream business and to ensure some supply security. Third, as gas and power markets (particularly in Europe) continue to liberalize, entry into upstream offers additional growth opportunities.

Multiple gas and power companies in Japan and South Korea have made a flurry of investments in midstream and upstream assets. Completely dependent on LNG imports for their gas supply, many of these utilities consider investments in small equity stakes in liquefaction projects as critical to securing necessary LNG volumes and improving reliability. The decisions by Mitsubishi, which functions as a supplier for Japanese utilities, and KOGAS to invest in LNG Canada can be viewed in this light.

Moving Downstream. Traditionally, much of the final price of gas, i.e. the value creation, was enjoyed by downstream utilities. For IOCs and NOCs, the prospect of seizing value by increasing presence and flexibility along the value chain has led to greater involvement in the midstream and downstream. This has led to stakes in regasification terminals, regasification capacity or downstream marketing joint ventures. In terms of their gas business, PetroChina's business model has increasingly moved from its traditional upstream strength in search of greater value located in the downstream. Several NOCs have also used this approach in reaction to maturing resource bases.

Flexible Marketing Model. The interest in deriving greater value from marketing has also come to influence the commercial terms of LNG contracts. The inclusion of destination flexibility clauses in LNG contracts first emerged as a hedge against unexpected reversals in gas demand. Companies increasingly saw an opportunity to diversify portfolios away from long-term, fixed destination contracts in favor of signing more flexible contracts. IOCs and NOCs have accordingly increased the share of flexible LNG in their portfolios over time. Several IOCs, including Shell, have pioneered the marketing of "portfolio contracts," which guarantee the delivery of a certain volume of supply, but do not specify from which liquefaction plant volumes are sourced. This has in turn allowed marketers of portfolio contracts to optimize LNG marketing from across their aggregated network of liquefaction assets.

Business Models and LNG Canada. LNG projects typically require several characteristics to succeed. Almost all LNG projects are joint-ventures with two or more partners involved. Successful projects tend to have partners that have experience in upstream development and in previous liquefaction projects. While there have been new entrants to the liquefaction space, they tend to be few and far between. Not only does experience lessen some of the technical and commercial risks associated with a project, but it also acts to reassure potential buyers that the project will be developed as planned. Also, many projects are joint-ventures between buyers and sellers. By combining the links in the chain, these projects develop longer lasting relationships between buyers and sellers and provide security of both supply and demand for the project. LNG Canada's project structure is a big asset in that regard and the Project's prospects are bolstered by its ownership structure. Shell, KOGAS, Mitsubishi, and PetroChina bring extensive experience in all aspects of LNG value chain including, upstream, liquefaction, shipping, regasification, and access for LNG output and access to financial, technical, and commercial resources. As a result, the players in LNG Canada together completely provide what is required for successful project execution.

Project Owners' Portfolios and Ability to Offtake LNG

Shell

Overview of Business Model, Strategy and Value Chain Participation

Shell is one of the world's largest IOC natural gas producers. Almost half of its hydrocarbon portfolio base comes from gas. Among its peers, Shell has the second largest overall gas reserves portfolio (7.85 billion barrels of oil equivalent (bn boe), smaller only than that of ExxonMobil.[24] The company's core gas businesses are Upstream International and Upstream Americas and it has a presence in 30 countries. Shell is one of the world's largest IOC LNG players and has positions in each part of the LNG value chain. The company plays a leading role at every stage of the LNG value chain, from upstream production facilities and liquefaction plants to shipping fleets, regasification facilities and pipeline networks, spread across basin networks. Early liquefaction investments focused on Asia Pacific, but Shell has since built up a global liquefaction portfolio, with a presence in Australia, Brunei, Malaysia, Nigeria, Oman, Russia, and Qatar. Starting in the 2000s, Shell developed its global regasification and trading capabilities to create a fully integrated, global LNG network. It has since expanded its trading activities to include a portfolio of LNG it can flexibly market from its various liquefaction projects.

The company is well positioned to execute a natural gas-to-LNG project in Canada for sales to global markets. Shell has extensive holdings in the western portion of Canada's Devonian/Mississippian Shale, including acreage in the Montney (Groundbirch) Area and shale assets acquired from Duvernay Oil in 2008. The company's proved gas reserves in Canada have upside potential, and its vast and integrated LNG portfolio has provided it with experience executing innovative and technically challenging LNG projects. Shell is also an industry leader in LNG contracting, and 70% of offtake from its LNG projects (gross) is currently contracted to Asian buyers.

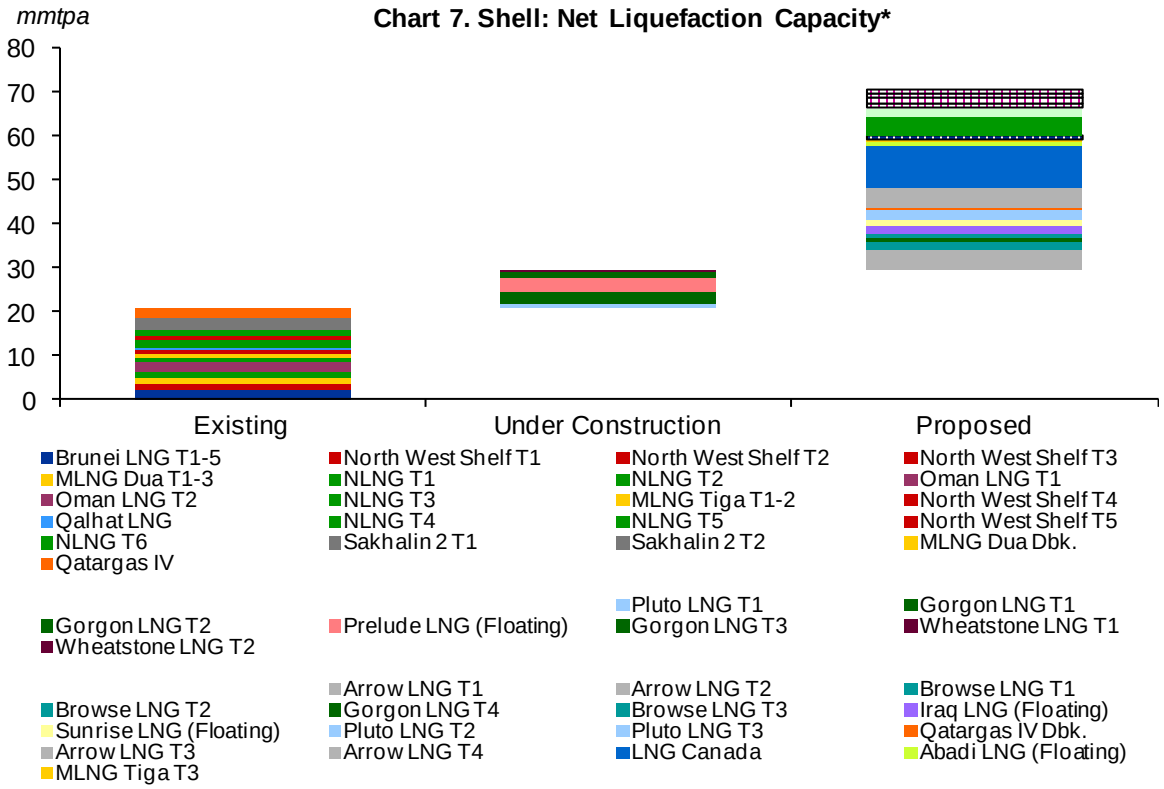
Liquefaction Positions. Shell is one of the few companies to have an LNG portfolio that truly can be described as an integrated global network (see Chart 7 below). The company has existing liquefaction assets in each of the three major basins (Atlantic, MENA, and Pacific) and has experience operating several of its liquefaction projects. As Shell has built its liquefaction portfolio, it has increasingly taken on technically difficult projects it is well positioned to execute, such as the world's first Floating LNG project at Prelude in Australian waters. It is also pursuing LNG projects based on coal bed methane (CBM), and shale gas.

Shipping. Shell's leadership in LNG trading is bolstered by its robust Shell Trading & Shipping arm, which oversees a small equity fleet and an operating subsidiary – Shell International Trading and Shipping Company (STASCO) – and engages in LNG trading. Shell began ordering undesignated tankers in the late 1990s to fully capitalize on global LNG spot and short-term contract trades. The company took delivery of five of these vessels between 2002 and 2004 and was the first oil major to develop a sales system for short-term LNG deals not linked to a specific source, capitalizing on its position as a major global LNG supplier.

The company uses its controlled fleet to maximize value added from spare capacity worldwide, by carrying spot cargoes to various terminal access points. For example, Shell used this strategy to deliver spot cargoes to the Hazira terminal in India, which came online in 2005. When possible, Shell leverages its shipping expertise either via STASCO operatorship or via equity stakes in ship-owning companies that service LNG projects with which Shell is involved. Through these equity stakes, Shell is the operator of more than 50 LNG carriers, four of which it wholly owns. Further, the company charters – on long-term and short-term contracts – vessels to facilitate trading. Shell currently has an undisclosed number of new

[24] *Based on proven reserves as reported in Shell and ExxonMobil 2010 Annual Reports.*

build vessels on order, which it intends to charter following their deliveries, all scheduled for delivery from 2013 to 2015.



**Includes Shell's indirect share via a 24% stake in Woodside Petroleum.*

KOGAS

Overview of Business Model, Strategy and Value Chain Participation

As a near-monopoly importer and supplier of natural gas in South Korea, KOGAS is the world's largest single importer of LNG, with 27.5 mmtpa of long-term contracted volumes and 33.6 mmtons of total gas sales in 2011. LNG imports represent 99% of Korea's natural gas supply, making it the world's second largest LNG region after Japan. KOGAS imports natural gas through its three LNG terminals, and then distributes gas to end-users. In 2010, KOGAS' sales divided into 33% residential & commercial, 21% industrial and 44% power generators.

KOGAS' largest challenge is meeting South Korea's seasonal demand, which fluctuates between summer low points and winter spikes. To deal with seasonality, KOGAS has sought flexible long-term contracts biased toward winter deliveries, and has traditionally maintained an above-average level of exposure to the spot market.

In an attempt to diversify its business model beyond gas procurement and distribution, KOGAS is moving further up the gas value chain and is becoming more involved in equity investments in liquefaction and upstream exploration and production for natural gas (including unconventional). Overall, KOGAS' strategy remains shaped by South Korean energy security objectives and the need for supply reliability. KOGAS' decision to acquire equity related to LNG procurement and E&P is rooted in its desire to improve the security of its supply.

Upstream

KOGAS has a geographically-diverse upstream portfolio. The company's equity stakes in upstream assets can be divided into pure E&P plays, and others associated with LNG production. Equity upstream interests are located in Canada, Iraq, Uzbekistan, Mozambique, Australia, Indonesia, Timor-Leste, and Myanmar. In addition to its LNG-focused upstream assets, KOGAS has made a number of investments in projects not explicitly tied to supplying South Korea. These include its upstream assets in Iraq, Uzbekistan and Myanmar, though LNG has in the past been discussed in Myanmar, and Iraq also has long-term potential.

KOGAS provides ~1% of South Korea's gas through its own production, mainly via limited production in South Korea.

Table 3. KOGAS: Upstream Gas Portfolio

Country	Type of Asset(s)	LNG Feedstock (Y/N)	Description of Assets
Indonesia	Conventional, CBM	Y	Stakes in Krueng Mane Block and Senoro-Toili field; latter will provide feedstock to Donggi-Senoro LNG project
Canada	Conventional, Shale Gas	Y	JV with Encana in the Montney and Horn River plays to provide feedstock to LNG Canada; Jackpine field in Alberta; Umiak Block in Canadian Arctic
Australia	CBM	Y	10% stake in CBM producer Blue Energy, 15% stake in Gladstone LNG includes interest in the upstream
Mozambique	Conventional	Y	Partnered with Eni in Area 4 Block, containing Mamba discovery that forms the basis for a proposed LNG project
Timor-Leste	Conventional	Y	Partnered with Eni in exploration Blocks S-06-01-A, B, C, E, H
Iraq	Conventional	N	Service contract to develop the Akkas gas field; partnered with Gazprom and PETRONAS in Badra oil and gas field; partnered with TPAO and Kuwait's KEC in Mansuriya gas field
Uzbekistan	Conventional	N	Developing Surgil gas field with Uzbekneftegaz
Myanmar	Conventional	N	Stakes in Blocks A-1 and A-3, which will supply gas to the under construction Myanmar-China pipeline

Production Outlook. KOGAS has very little existing equity gas production, but plans to increase equity production from ~1% currently to 25% by 2017. To do this, it has built up an upstream position that includes feedstock to the under-construction Donggi-Senoro LNG in Indonesia, and Gladstone LNG in Australia. Longer term, KOGAS is likely to add gas production in other areas as well, including potential supply to future liquefaction projects, the most advanced of which is currently LNG Canada. Mozambique also has long-term potential. Beyond LNG, KOGAS could add equity gas production in Iraq, Uzbekistan and Myanmar, though the size and timing of potential production remains uncertain.

Midstream Gas – LNG and Pipeline

KOGAS has assets throughout the LNG value chain, including stakes (and proposed stakes) in liquefaction assets in the Middle East, Southeast Asia, Australia and Canada. For many of these, KOGAS is also involved in upstream assets that will or could provide feedstock gas. KOGAS has a large slate of long-term LNG contracts, and brings gas into its three regasification terminals in South Korea.

After moving up the value chain and establishing a foothold in midstream liquefaction assets, KOGAS has extended its reach and geographic scope. Equity participation in liquefaction and associated upstream

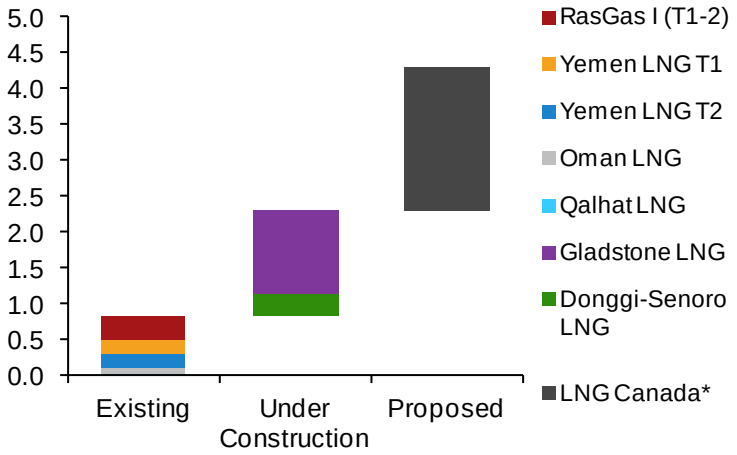
assets offers KOGAS an increased sense of control over its LNG procurement. In 2012, KOGAS has 0.83 mmtpa of equity liquefaction capacity and 1.83 mmtpa in projects under construction. It also has 79.5 mmtpa of existing regasification capacity in South Korea, along with another 6.8 mmtpa currently under construction.

Liquefaction. KOGAS' existing liquefaction interests are all in the Middle East: it has minority stakes in Qatar's RasGas I project, Yemen LNG T1-2, and Oman LNG and Qalhat LNG in Oman.

In December 2010, KOGAS obtained a 15% stake in Gladstone LNG project (1.17 mmtpa capacity stake). Final investment decision (FID) was reached in January 2011 and the project is under construction.

In January 2011, KOGAS acquired a 15% equity stake in the Donggi-Senoro LNG project via its cooperation with Mitsubishi, a 45% stakeholder. This provides KOGAS with 0.3 mmtpa of the project's capacity. The project is announced to start in 2014.

Chart 8-A. KOGAS: Net Liquefaction Capacity



**Equity stakes in LNG Canada are not yet finalized, PFC Energy has assumed a 20% stake.*

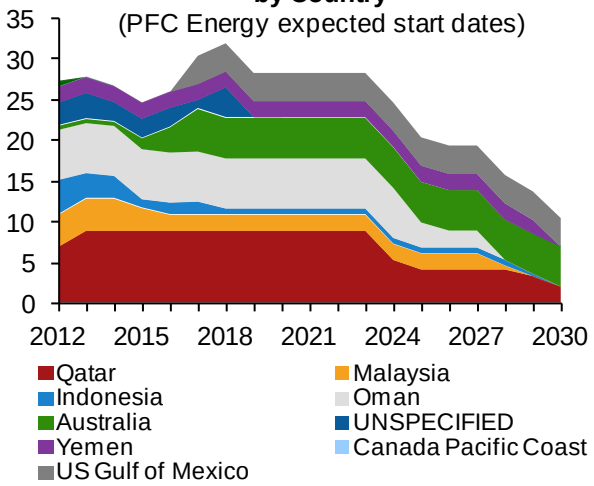
In February 2012, KOGAS was reported to be considering teaming up with Mitsui and Japan Petroleum Exploration to take a stake in Interoil's proposed Gulf LNG project in Papua New Guinea. However, negotiations are ongoing and no deal has yet been announced.

Shipping. KOGAS is involved in LNG shipping. While it does not have ownership stakes in any ships, it has long-standing successful joint ventures chartering ships from Hyundai, Korea Line, and SK Shipping for LNG imports.

Contracted Pipeline and LNG Positions. KOGAS and the South Korean region in general do not have pipeline gas supply. A future pipeline from Russia through North Korea has been discussed, but little progress has been made, and this is a long-term and highly uncertain prospect given commercial, feedstock, geopolitical and other concerns.

In LNG, KOGAS has a diversified portfolio, where it currently buys gas from eight countries plus contracts with BG, Shell, Repsol and GDF SUEZ for LNG from those companies' portfolios ("unspecified" in Chart 8-B). It expects to add the US to this once Sabine Pass LNG comes online, and could also add LNG from Canada via LNG Canada. KOGAS has a stable contracted supply of over 25 mmtpa, rising to ~30 mmtpa by 2019, and

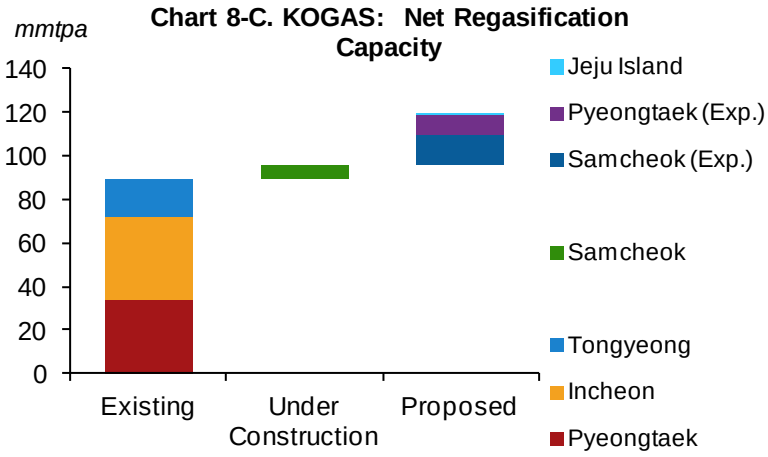
Chart 8-B. KOGAS: LNG Contracts by Country
(PFC Energy expected start dates)



lasting until 2023, after which its contracts start to expire.

Without its own production or storage assets to flexibly deal with seasonal fluctuations in domestic demand, KOGAS must guarantee secure supplies while also pursuing flexibility in its contracts to manage seasonal swings. In pursuing supply security, KOGAS must find a balance between an over-reliance on long-term take-or-pay contracts and exposure to the spot market, which can exhibit substantial short-term price volatility.

Regasification. KOGAS operates three out of the four existing terminals in Korea, accounting for 97% of total import capacity. South Korea's fourth terminal at Gwangyang is jointly owned by K-Power and steel-maker POSCO, which can import LNG for proprietary purposes.



** Terminal access based on leased sendout capacity and/or ownership interest in existing and planned terminals*

KOGAS' three regasification terminals offer total capacity of 89 mmtpa (see Chart 8-C):

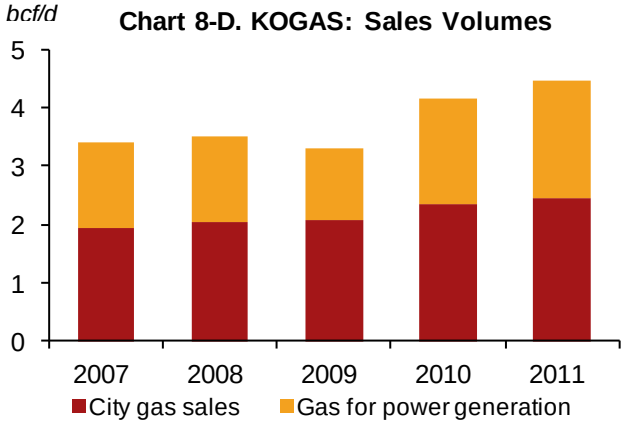
- **Incheon:** located in the Seoul region, has 38 mmtpa of capacity.
- **Pyeongtaek:** located in the Seoul region, has 34 mmtpa.
- **Tongyeong:** located on the country's far southern coast, has 17 mmtpa

This is sendout capacity, and indicates the volume of gas that could be pushed into the Korean pipeline system from the terminals. PFC Energy finds that KOGAS' capacity to import LNG is considered to be higher than its current needs.

Recently, both the Incheon and Pyeongtaek terminals have been upgraded in order to receive cargoes from Qatar's Q-Max ships (262,000 to 265,000 m^3). KOGAS is also building the Samcheok terminal along South Korea's eastern coast, 180 miles from Seoul. Upon the completion of phase 1 in 2013, Samcheok will have a sendout capacity of 780 mt/hour and 6.8 mmtpa of gross capacity in its first phase. The Samcheok terminal may eventually be expanded to a total gross capacity of 13.7 mmtpa.

Gas Marketing Strategy

KOGAS currently does not engage in trading or marketing of its equity offtake and contracted LNG, but rather procures LNG to bring to its home market via its wholly-owned regasification facilities. It then markets regasified LNG in South Korea as a monopoly gas supplier (with minor exceptions for LNG imported by other companies for their own use only).



South Korea is the second largest LNG market in the world, relying on LNG imports for 99% of its

natural gas needs, thus making KOGAS the world's largest single LNG importer.

KOGAS' 2010 total gas sales increased by 27% to 1,500 bcf, and then again by 7.6% in 2011 to 1,600 bcf (as shown in Chart 8-D). The 2010 and 2011 increases were driven by large increases in power demand: 50% in 2010, and 12% in 2011. City gas demand increased 13% in 2010 and 4% in 2011. This was driven by the strong rebound in economic growth in 2010 following the 2009 recession, and continued positive economic performance in 2011.

Due to major seasonal temperature changes, South Korean gas demand is highly cyclical. Winter demand, driven by residential heating, is typically 75-80% higher than summer demand. South Korea's LNG imports in the winter are typically double summer demand levels as a result.

Need to Secure / Ability to Absorb LNG Offtake

KOGAS is almost solely responsible for meeting Korean gas demand, and as such is among the world's premier LNG buyers, with a high need to secure LNG and an ability to absorb new volumes that corresponds to the growth in Korean demand, coupled with its own long-term contracted position.

KOGAS' long-term LNG contracts provide for a relatively stable volume of deliveries through the mid-2020s, and then begin to expire. But even in the 2015-2020 timeframe, the growth in South Korean gas demand is projected to create a growing supply gap: ~6 mmtpa by 2015, and ~7 mmtpa by 2020, and widening much further thereafter to 18 mmtpa by 2025, and 37 mmtpa by 2030.

Under current South Korean law, KOGAS bears nearly exclusive responsibility for closing this gap and meeting demand.[25] And even if gas market deregulation occurs, KOGAS has long-standing relationships with its customer base, holds the majority of the country's regasification capacity, and will remain the only company positioned to meet the majority of South Korea's gas demand for many years, meaning that its long-term need for new LNG will continue to grow. Based on the company's existing LNG contract portfolio going forward, and projected growth in South Korean gas demand, KOGAS will be able to absorb new volumes of LNG from LNG Canada.

LNG buyers tend to prioritize supply from projects in which they hold equity stakes, because by doing so they are able to capture higher value than by sourcing supply from projects lacking this vertical integration. Given this, securing gas supply from LNG Canada may be more favorable to KOGAS as compared to sourcing LNG from other LNG projects in which the company does not hold an equity stake.

[25] *A series of bills aiming to deregulate the South Korean gas market have been introduced in the legislature since 2009, but have been repeatedly delayed. The government intends to implement a gradual opening of the sector to competition that protects KOGAS' interests while also allowing for increased competition. The details of the eventual reform and timeline for its passage and implementation remain uncertain, however, and even if it is passed the impact on KOGAS is likely to be felt only over the long term.*

PetroChina

Overview of Business Model, Strategy and Value Chain Participation

PetroChina is the dominant upstream player in onshore China, has substantial pipeline imports both existing and planned, and is also a major LNG importer. Gas in general is a dynamic and rapidly growing part of the company's overall strategy, and with Chinese demand expected to continue to grow rapidly, PetroChina is well-positioned to maintain its role as the principal supplier to much of the country.

In PetroChina's core business of domestic E&P, it continues to perform very well, with growing gas reserves and production. The NOC is also the dominant midstream player, and its domestic pipeline network continues to grow, including two successful West-East trunkline projects, and plans for as many as three more. In LNG and pipeline imports, PetroChina has reached many milestones in 2009-2011, including the start of pipeline and spot LNG imports, as well as entering Australia's CBM-to-LNG industry. To date, PetroChina has procured an impressive ~5.3 bcf/d of pipeline and LNG imports, with preliminary deals for more.

In gas marketing, PetroChina continues to see sales growth, but managing long-term contracts in addition to rising seasonality is a challenge. Moreover, PetroChina hopes for reform to the gas pricing system to support more imported gas volumes in PetroChina's marketable gas portfolio.[26]

Internationally, PetroChina is building an integrated gas import strategy, and has achieved notable success. It has upstream and midstream (pipeline and liquefaction) positions in existing and proposed gas import schemes into China, including a pipeline from Central Asia and LNG imports from Australia. It has also invested in Canadian gas with an intention to ship LNG to China.

Upstream

PetroChina's core gas business is in China, where it benefits from parent CNPC's historic onshore monopoly. China accounts for ~99% of PetroChina's proven gas reserves, though positions in Australia, Turkmenistan, and Canada could change this as reserves are proven going forward.

Internationally, PetroChina has developed a focused position with notable upstream gas operations in Canada, Indonesia and Turkmenistan. In Canada, PetroChina finalized a 20% stake in Shell's Groundbirch shale assets in British Columbia in February 2012. The acreage is already producing gas, and could be expanded if it is used to provide feedstock to LNG Canada. Indonesia was the NOC's first foray abroad in 2002 and it continues to expand, though on a smaller scale than in Turkmenistan, the source of major pipeline imports and an emerging gas power with one of the world's largest fields. PetroChina hopes to expand its presence in Kazakhstan and Uzbekistan, though upstream prospects there are smaller scale. PetroChina also has upstream positions in Latin America, but only in oil. Lastly, the NOC has an exploration agreement in Qatar's gas-prone pre-Khuff.

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[26] *Gas prices in most of China are set by the government, and are not directly linked to oil or any other market-priced commodity except under a pilot program currently being implemented in Guangdong and Guangxi provinces. The government has long promised reforms to bring domestic prices in line with higher import prices and facilitate expanded gas use. While this is countered by a desire to curb inflation and protect industries like fertilizer that have long enjoyed inexpensive gas, the policy trajectory is towards reform and eventual harmonization of domestic prices with import prices. The specific timetable and pace of reform remains uncertain, however as the share of imports in Chinese gas consumption continues to grow, pressure for reform will continue to mount. However, particularly in the case of PetroChina, its ability to blend its higher priced imported LNG with lower cost domestic production in its extensive and increasingly interconnected pipeline network insulates it somewhat from the current price differential, allowing it to continue to expand LNG imports despite their relative high price.*

Table 4-A. PetroChina: Upstream Gas Portfolio

Country	Type of Asset(s)	LNG Feedstock (Y/N)	Description of Assets
China	Conventional, CBM	N	Major producer in most of China's major onshore basins
Australia	Conventional, CBM	Y	Partnered with Shell in upstream for Arrow LNG project
Canada	Conventional, Shale Gas	Y	Assets in Western Canada, including stake in Shell's Groundbirch shale gas assets, which could provide feedstock to LNG Canada
Kazakhstan	Conventional	N	Oil production with potential gas upside, including Urikhtau gas field, which could supply Central Asia Gas Pipeline, which supplies PetroChina's West-East pipeline network
Turkmenistan	Conventional	N	Operator of the Amu Darya PSC, which provides most existing feedstock to Central Asia Gas Pipeline; also has a contract to develop giant South Yolotan field
Uzbekistan	Conventional	N	Partnered with Uzbekneftegaz in several exploration blocks
Qatar	Conventional	N	Partnered with Shell in deepwater exploration Block D, exploring for gas in Pre-Khuff play
Indonesia	Conventional	N	Several producing PSCs including South Jambi, Jabung and Kepla; also developing Kepala Burung PSC and Salawati gas field

Production Outlook. PetroChina was able to grow its worldwide gas production at a 14.7% CAGR in 2006-2010, driven by growing production in China. Production in China reached 5.9 bcf/d in 2010. It has so far been less successful in making international gas production a major part of its portfolio; production outside of China was 231 mmcf/d in 2010 (see Chart 9-A). However, production ramping up in Turkmenistan through 2011 will contribute new volumes over the medium term, and PetroChina could also possibly add volumes in Kazakhstan and Uzbekistan. PetroChina is expected to add LNG feedstock production in Australia and Canada to this by the end of the decade. In total, PetroChina has over 5 bcf/d in currently identified new source gas projects expected to come online over the coming decade, including the country's first PSC with a foreign company to produce shale gas – a partnership with Shell on the Fushun-Yongchuan block in Sichuan province. While much of this will serve to offset declines in its portfolio of currently

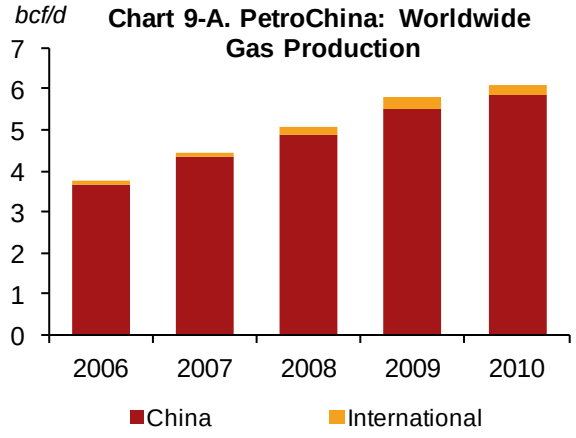


Chart 9-A. PetroChina: Worldwide Gas Production

producing projects over that period, PetroChina is nonetheless well-positioned to continue to see overall growth in its gas production.

Midstream Gas – LNG and Pipeline

PetroChina's LNG strategy is to expand further up the LNG value chain in order to: 1) increase supply security; 2) add equity LNG to its portfolio for more flexibility; and 3) further integrate to increase value in its LNG business. It is doing this with major LNG player Shell through the two companies' Arrow Energy LNG CBM-to-LNG project in Australia, and LNG Canada.

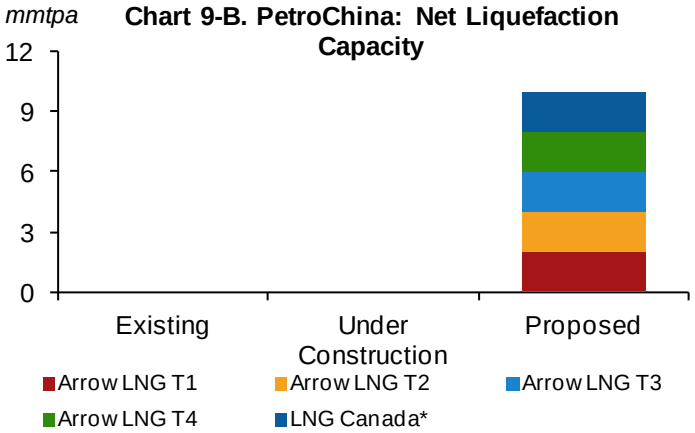
For PetroChina, its LNG business is a way for the company to secure new long-term gas supply for the domestic market. It is also keen to use LNG to manage peak demand and add flexibility to its portfolio by linking regasification terminals to its domestic pipeline infrastructure.

Liquefaction. In 2010-2011, PetroChina has gotten involved in two proposed LNG projects: the first was its joint acquisition with Shell of Arrow's CBM assets and proposed LNG plant in 2010; and the second is LNG Canada in 2011 (as shown in Chart 9-B).

Shell announced in 2011 that it would enter into a joint venture with Petrochina, KOGAS and Mitsubishi to build up resources for a potential LNG project, LNG Canada. PetroChina has a 20% stake in Shell's Groundbirch shale gas assets in British Columbia.

Shipping. PetroChina does not have interests in any LNG ships.

Chart 9-B. PetroChina: Net Liquefaction Capacity



**Equity stakes in LNG Canada are not yet finalized, PFC Energy has assumed a 20% stake.*

Gas Storage. Growing seasonality and several years of winter gas shortages in major northern China gas markets have prompted PetroChina to seek to expand its currently minor gas storage footprint. PetroChina plans to build 10 gas storage facilities in China by 2015, targeting a working storage capacity of 22.4 bcm (~800 bcf, which is ~15% of 2011 demand).

Pipeline Contracts. Over the past five years, PetroChina has been able to bring the 3.9 bcf/d Central Asia Gas Pipeline online, secure a 2.9 bcf/d gas export agreement from Turkmenistan, sign initial deals for another 2.9 bcf/d of supply from Central Asian nations, and begin work on a 500 mmcf/d import pipeline from Myanmar that could eventually be expanded to ~1.16 bcf/d (as shown in Table 4-B). The Central Asia Gas Pipeline feeds into PetroChina's second West-East Pipeline (WEP-2) at the Chinese border.

PetroChina began importing gas from Turkmenistan in January 2010, establishing China as a pipeline gas importer. Turkmenistan has agreed to supply the Chinese NOC for 30 years with 2.9 bcf/d (~22 mmtpa or 30 bcm/a), and volumes ramped up steadily in 2010-2011. China National Petroleum Corporation (CNPC), PetroChina's parent company, has an initial agreement with Turkmenistan for another 970 mmcf/d (10 bcm/yr). It has also signed preliminary agreements with Kazakhstan and Uzbekistan for 970 mmcf/d of imports each. Any of these agreements could fill remaining capacity.

In December 2008, CNPC signed a 30-year GSA with Daewoo (which leads a consortium of Myanmar Oil and Gas Enterprise, KOGAS, Oil and Natural Gas Corporation (ONGC), and GAIL) for the gas from Blocks A-1 and A-3 to be transported by the Myanmar-China pipeline. Plateau volumes will be 500 mmcf/d. PetroChina has also discussed adding another 661 mmcf/d, but the timing and other details remain unclear.

Table 4-B. PetroChina: Gas Imports

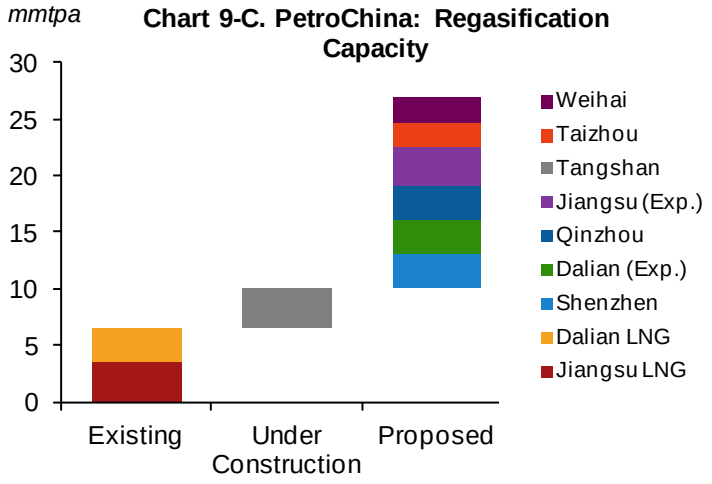
	Source	mmcf/d	bcm/yr
Secured Imports			
Pipeline	Turkmenistan	3,870	40.0
Pipeline	Myanmar	500	5.2
Total Secured Pipe Imports for 2020		***4,370***	***45.2***
LNG	Qatargas IV	398	4.1
LNG	Shell (Gorgon, Global Portfolio)	265	2.7
LNG	Gorgon LNG T1-3 (XOM)	298	3.1
Total Secured LNG Imports for 2020		***961***	***9.9***
Total Secured Imports for 2020		***5,331***	***55.1***
Potential Imports			
Pipeline	Turkmenistan (Additional)	2,419	25.0
Pipeline	Kazakhstan	968	10.0
Pipeline	Uzbekistan	968	10.0
Pipeline	Myanmar (Additional)	661	6.8
LNG	Arrow Energy LNG T1-2	530	5.5
LNG	Wheatstone (MOU)	232	2.4
Additional Potential Imports by 2020-2030		***5,777***	***59.7***
Potential Longer-Term Imports			
Pipeline	Russia	2,900-5,800	30-60

PetroChina has held talks with Gazprom about several proposed pipeline routes to carry Russian gas into China, but negotiations have so far not led to significant progress on any of these proposals.

LNG Contracts. To date, PetroChina has secured 7.25 mmtpa in term LNG, due to start up between 2011 and 2018. With a traditionally conservative policy of building regasification terminals to match contracts, the NOC brought its first and second LNG terminals online in 2011 and has a third under construction, with a total capacity of 10.5 mmtpa.

PetroChina has been able to build up a sizeable portfolio of long-term LNG contracts. A tighter LNG market post-2014 will stiffen competition, but PetroChina is becoming a successful buyer as it is increasingly is able to resell LNG to users in China and also offer upstream stakes in China to potential liquefaction co-venturers.

Chart 9-C. PetroChina: Regasification Capacity



Regasification. PetroChina brought online its first two regasification terminals in 2011, and has another under construction. While China National Offshore Oil Company (CNOOC) remains the primary importer of LNG into China, PetroChina will have 10.5 mmtpa of capacity once its Tangshan terminal is complete, and has a slate of proposed terminals totaling another 22.6 mmtpa, a little more than half of CNOOC's slate of existing and proposed capacity (see Chart 9-C above).

PetroChina's strategy is to integrate LNG terminals with its vast domestic gas pipeline infrastructure, which gives the NOC a competitive advantage over its peers, which have much less developed onshore transportation and distribution networks, and must rely on local demand near their terminals.

In addition to securing term supply, PetroChina also plans to use LNG imports for peak-shaving purposes, as a back-up source of gas and a way to increase flexibility in meeting its procurement needs. China is rather conservative in its regasification build-up: long-term contracts are often paired with planned terminals before construction starts. As a result, PetroChina's regasification outlook is correlated to that of its LNG supply, and it can be expected to move forward with a new terminal (or expansion of capacity at one of its existing terminals) in concert with development of LNG Canada.

PetroChina's first terminal, the 3.5 mmtpa terminal in Rudong, Jiangsu province received its first commissioning cargo in May 2011, and by August had received two more and was fully operational. The company's second terminal, a 3.5 mmtpa terminal in Dalian, Liaoning province, started up in November 2011. The third terminal is located in Tangshan, Hebei Province and scheduled to be completed and started-up by the end of 2012 PetroChina is also planning to double capacity at both its Dalian and Jiangsu terminals. Long-term LNG supply from Qatargas IV and Gorgon LNG will supply these terminals.

Gas Marketing Strategy

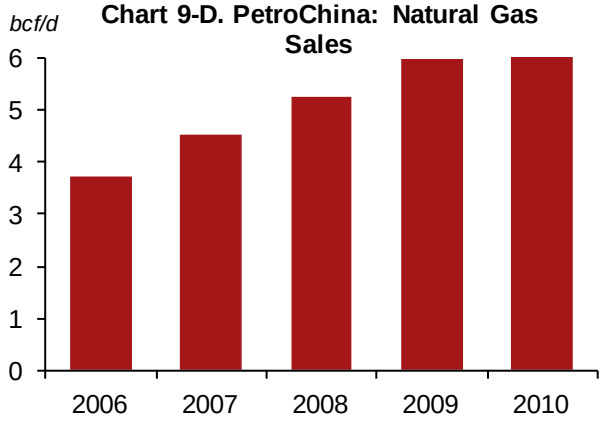


Chart 9-D. PetroChina: Natural Gas Sales

PetroChina procures LNG to bring to its home market through its wholly-owned regasification facilities. It then markets regasified LNG in China through its network of gas pipelines.

PetroChina is the largest gas supplier in China and its strategy is to market gas into the Chinese market on a diversified basis.

An emerging exception to this core strategy is PetroChina's decision to use regasified LNG imports to meet peak demand and allow for the signing of more flexible contracts. Linking regasification terminals with its domestic pipeline network allows regasified LNG to reach many customers, putting PetroChina at an advantage in LNG marketing relative to LNG player CNOOC.

Managing peak demand has become a larger challenge for the NOC, due to the rising complexity and seasonality of Chinese gas demand. The country grappled with winter gas shortages, forcing cuts to industrial users, and PetroChina has accelerated efforts to complete new regasification, pipeline and storage infrastructure to avoid repeating this situation.

In late 2010, it connected new supply to Beijing and Tianjin via the third Shaanxi-Beijing pipeline, as well as an interconnector to WEP-2, allowing a range of supply sources to reach the capital area. The

company also turned to the spot LNG market in 2010 and 2011, importing cargoes via leased capacity at CNOOC's Shanghai terminal.

PetroChina's first term LNG supply from Qatargas IV commenced with the start of its first regasification terminal in Jiangsu province in 2011. It will add two more terminals by the end of 2012. All three of these import terminals will be critical to the company's flexible supply strategy, as regasified LNG can be placed into its extensive domestic pipeline grid and blended with other gas to offset import prices and meet swings in demand.

PetroChina's gas sales portfolio rose ~6% in 2010, following a 17% climb in 2009 and is expected to continue strong growth in line with rising domestic production and pipeline and LNG imports. Pipeline access and the ability to bring gas to market is a cornerstone of PetroChina's gas business and it continues to expand its reach. Completion of the eastern leg of the WEP-2 in 2011 expanded access into southern gas markets.

Need to Secure / Ability to Absorb LNG Offtake

As the dominant incumbent gas supplier throughout China, PetroChina's gas procurement needs are growing rapidly as Chinese demand grows. While it increasingly must compete in this realm with its peers CNOOC and Sinopec, PetroChina still supplies the bulk of Chinese gas, and will continue to have large procurement needs going forward.

Gas demand in China is projected to reach ~160 mmtpa by 2015, and ~220 mmtpa by 2020, with a supply-demand gap of 17 mmtpa emerging by 2020. After this, the gap grows even wider, reaching 47 mmtpa by 2025 and 180 mmtpa by 2030. This gap is already taking into account all of the pipeline and LNG contracts discussed above, so PetroChina will need to seek more LNG, through new and/or renewed contracts, to help close this gap. Based on the company's existing LNG contract portfolio going forward, and projected growth in Chinese gas demand, PetroChina will be able to absorb new LNG from LNG Canada. Moreover, because LNG buyers tend to prioritize supply from projects in which they hold equity stakes, PetroChina may prioritize receipt of LNG from LNG Canada as compared to other projects in which it does not hold stakes. By sourcing gas from LNG Canada, in which it is involved, PetroChina would be able to capture higher value than by sourcing supply from projects lacking this vertical integration.

Mitsubishi

Overview of Business Model, Strategy and Value Chain Participation

Mitsubishi is a Japanese conglomerate whose interests in the natural gas sector are concentrated in upstream and LNG. The company has mostly non-operated upstream gas interests in Indonesia, Malaysia, Australia, Brunei, Vietnam, Russia, the US Gulf of Mexico, Canada, and Iraq. Many, but not all of these assets provide feedstock to LNG projects. Mitsubishi is also an LNG supplier to Japanese LNG buyers, and re-contracts some of its own equity LNG offtake. While the company has one existing LNG contract that it markets on its own, it has ambitions to grow its LNG offtake.

Upstream

Mitsubishi's upstream interests are geographically widespread, and it is a minority, non-operating partner in the majority of these assets. The company has stakes in upstream feedstock to the North West Shelf (Australia), Sakhalin 2 (Russia), Malaysia LNG, Tangguh LNG (Indonesia), and Donggi-Senoro (Indonesia) LNG projects. It is likely to add LNG Canada to this list through its shale gas interests in western Canada, where it is partnered with Encana in the Cutbank Ridge shale play, and with Penn West Energy in the Cordova Embayment. Mitsubishi also has a proposal to liquefy gas production from its South Gas project with Shell in Iraq. Moreover, the company has stakes in upstream assets with gas production (or exploration blocks with gas potential) that are not connected to LNG projects in Indonesia, Malaysia, Vietnam, and the US.

Production Outlook. Mitsubishi has seen rapid growth in its natural gas production since 2008, growing ~63% in 2009, and ~50% in 2010, and reaching close to 600 mmcf/d (as shown in Chart 10-A). Going forward, Mitsubishi has potential upside in gas in several areas, including stakes in new LNG feedstock fields for North West Shelf and the third train at Tangguh. It is also likely to see new production over the longer term in Canada and Iraq. It also has ongoing exploration efforts in Brunei, Vietnam, and the US Gulf of Mexico.

Chart 10-A. Mitsubishi: Worldwide Gas Production

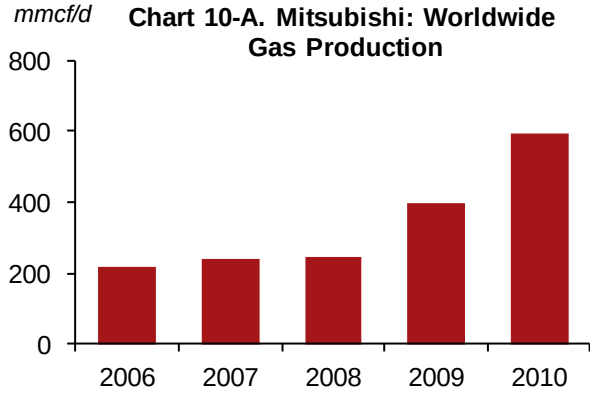


Chart 5. Mitsubishi: Upstream Gas Portfolio

Country	Type of Asset(s)	LNG Feedstock (Y/N)	Description of Assets
Indonesia	Conventional	Y	Indirect 19.97% stake in Indonesian E&P player Medco Energi Internasional; direct stakes in upstream feedstock for Tangguh LNG, and also in Senoro-Toili field, which will provide feedstock to Donggi-Senoro LNG, and also stakes in the Kangean and Krueng Mane PSCs
Australia	Conventional	Y	In partnership with Mitsui, 16.67% stake (net 8.33% stake) in the upstream feedstock for North West Shelf LNG
Brunei	Conventional	Y	Partnered with PETRONAS in exploration Block CA-2, which had formerly been disputed with Malaysia; any gas discoveries are likely to feed Brunei LNG
Malaysia	Conventional	Y	Stake in one field that provides feedstock to the MLNG Tiga plant, and also interests in several exploration blocks
Vietnam	Conventional	N	Partnered with JX Holdings, ConocoPhillips and Petrovietnam in the Rang Dong field
Russia	Conventional	Y	Partnered with Shell, Gazprom and Mitsui in upstream feedstock for Sakhalin 2 LNG project
United States	Conventional	N	Stakes in 20 Gulf of Mexico leases, nine of which contain producing assets
Canada	Conventional, Shale Gas	Y	Partnered with Encana in the Cutbank Ridge shale play, and with Penn West Trust in the Cordova Embayment; could eventually send its production to the LNG Canada project
Iraq	Conventional	Y	Project, which involves capturing and producing associated gas from oil fields in southern Iraq; the partners have also proposed a floating liquefaction project to monetize the gas

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Midstream Gas – LNG and Pipeline

Mitsubishi has been active in liquefaction since the 1970s, when it took a 25% stake in Brunei LNG and began playing its role as supplier to the Japanese market. It now has stakes in six existing projects (plus proposed expansion trains at three of those projects), one under construction project, and three proposed greenfield LNG projects.

During the 2000s, Mitsubishi made some initial forays into LNG trading and regasification. It signed its first LNG contract in 2004, for deliveries beginning in 2006, and also chartered a ship to go with it. . Mitsubishi has sent its Omani LNG to Japan and (occasionally) South Korea. At the same time, it has continued to actively seek out new liquefaction opportunities.
The also company contracted capacity at the Freeport LNG regasification facility in 2008 (though Freeport did not come online until 2011), when it still appeared that the US would become a major LNG importer
Mitsubishi's greatest strength is as a long-standing LNG supplier. In addition to its growing experience as a partner and operator in liquefaction projects, the company has deep relationships with Japanese LNG buyers and can facilitate the marketing of LNG there.

Liquefaction. Mitsubishi has minority stakes in many existing projects, with a net equity position totaling 7.76 mmtpa, and has built this portfolio over several decades (as shown in Chart 10-B). Its projects are located in the Pacific Basin and Middle East, chosen specifically to aid in securing LNG for the Japanese market.

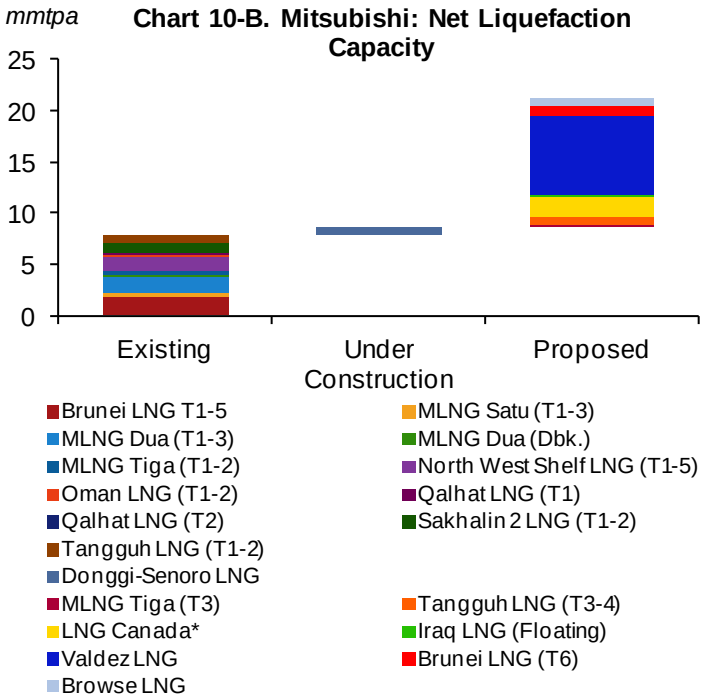

Chart 10-B. Mitsubishi: Net Liquefaction Capacity

**Equity stakes in LNG Canada are not yet finalized, PFC Energy has assumed a 20% stake.*

Mitsubishi has traditionally entered LNG projects primarily as a non-operating stakeholder. This changed when it entered the Donggi-Senoro LNG project in 2007, initially taking a 60% stake, later reduced to 45%. The reflects a shift in the firm's LNG strategy—Mitsubishi now seeks to play a more active role in its LNG ventures, and its operatorship of Donggi-Senore provides it with experience in this area that, when added to its strength as a supplier with deep relationships in the Japanese LNG import sector, makes the company a valuable Project Owner. Beyond this, Mitsubishi has stakes in proposed expansion trains at two of its existing LNG projects: Tangguh LNG, and Brunei LNG. Operator BP is moving forward with Tangguh train 3, and a fourth train is also possible eventually. Brunei LNG has long considered adding a sixth train; however this project's progress will depend on more discoveries being made in the country.

In May 2012, Mitsubishi announced that it and Mitsui would each acquire 7.35% stakes in Woodside's Browse LNG project. The stakes comes out of Woodside's share, and makes the partnership structure the same as at North West Shelf (though with different ownership stakes). Mitsubishi will also have capacity rights at Sempra's proposed Cameron LNG project in the United States. The proposal is in the

early stages and no start date has been announced, but if it moves forward will be built as a tolling facility where capacity holders pay a fee for liquefaction and source their own gas.

Finally, Mitsubishi is involved in LNG Canada, as well as other proposals. Iraq LNG is planned as a potential monetization option for Shell and Mitsubishi's South Gas project.

Shipping. Mitsubishi has a 25% stake in Brunei Shell Tankers, which owns the seven ships under long-term charter to Brunei LNG. It also charters one ship, which handles its contracted volumes from Oman LNG.

Contracted Pipeline and LNG Positions. In the projects in which it has equity stakes, Mitsubishi has mostly sought to link output to long-term contracts with Japanese utility buyers. However, it also has contracts where it is the seller of the LNG. In addition to the above contacts, Mitsubishi has one current LNG contract as an LNG buyer, for 0.8 mmtpa from Oman LNG. The company lifts the LNG itself using its chartered vessel, and has the right to market it flexibly. The contract expires in 2020.

Gas Marketing Strategy

In addition to its involvement in upstream and liquefaction, Mitsubishi is a trading house. It concentrates on producing LNG and selling it directly to Japanese utility buyers, or acting as an LNG supplier to the Japanese region. Whether through liquefaction or shipping, it is involved with ~40% of the LNG imported into Japan by volume, making it a major player in Japan, with relationships that facilitate marketing of supplies to Japanese buyers.

Need to Secure / Ability to Absorb LNG Offtake

Rather than meeting procurement needs of its own, Mitsubishi brings to its liquefaction interests its role as a supplier to LNG buyers in the world's largest and most important LNG market. All of the projects in which it has equity have featured stable, long-term, oil-linked contracts with Japan. And while Mitsubishi's involvement is not an exclusive prerequisite for successful LNG sales to Japan, the company is also a proven co-venturer with strong finances and strong relationships in its home market that can add value to its projects' marketing efforts. Mitsubishi may leverage its relationships in Japan to bring key Japanese LNG buyers into the LNG Canada project, not only as buyers but also as strategic investors. Japanese utility LNG buyers have taken minority stakes in a number of projects, bringing financial strength and secure market access in exchange for a more integrated position that adds to their security of supply. Given that Mitsubishi can play a key role in facilitating such relationships, it has the potential to add greatly to LNG Canada's marketing prospects.

Conclusion

Taken together, the upstream and marketing experience of the parent companies of the Project Owners will greatly benefit LNG Canada in monetization of gas and in the effective execution of this project. Successful projects tend to have partners that have experience in upstream development and in previous liquefaction projects. Many projects have also benefited from including both LNG buyers and sellers in the partnership structure. By combining these segments of the value chain, the Project Owners will be able to develop longer-lasting relationships between buyers and sellers and provide security of both supply and demand for the project. The LNG regions in which the Project Owners have established relationships—namely Japan, Korea, and China—are projected to have strong growth in LNG demand from 2020 onwards. The Project Owners are well-positioned to supply LNG to global markets, including these three regions, which combined will need to secure an additional 49 mmtpa of gas by 2020 and 112 mmtpa of gas by 2025, taking into account projected gas production and existing LNG and gas pipeline contracts. In addition, the Project Owners are well-positioned to sell gas into Taiwan from 2020 onwards and potentially into India and other emerging LNG markets such as Vietnam, Thailand, Singapore, Malaysia, and Indonesia. Gas marketed by the Project Owners will be attractive to buyers as it will allow them to diversify their LNG supply portfolio. In sum, the LNG Canada Project has many strengths which are required for successful project execution.

Appendix: Glossary & Units

Glossary

HOA: Heads of Agreement

IOC: International Oil Company

JV: Joint Venture

JCC: Japan Customs Cleared

MENA: Middle East and North Africa

NOC: National Oil Company

OECD: Organisation for Economic Co-operation and Development

PAJ: Petroleum Association of Japan

PSC: Production Sharing Contract

SPA: Sales and Purchase Agreement

Units

BCF/D: Billion cubic feet per day

GWH: Gigawatt hours

KTOE: Thousand tons of oil equivalent

MMBTU: Million British thermal units

MMCF/D: Million cubic feet per day

MMTOE: Million tons of oil equivalent

MMTPA: Million tons per annum

TWH: Terawatt hours

Companies

CNOOC: China National Offshore Oil Company

CNPC: China National Petroleum Corporation

GAIL: Gas Authority of India

KEPCO: Korea Electric Power Corporation

KOGAS: Korea Gas Corporation

ONGC: Oil and Natural Gas Corporation