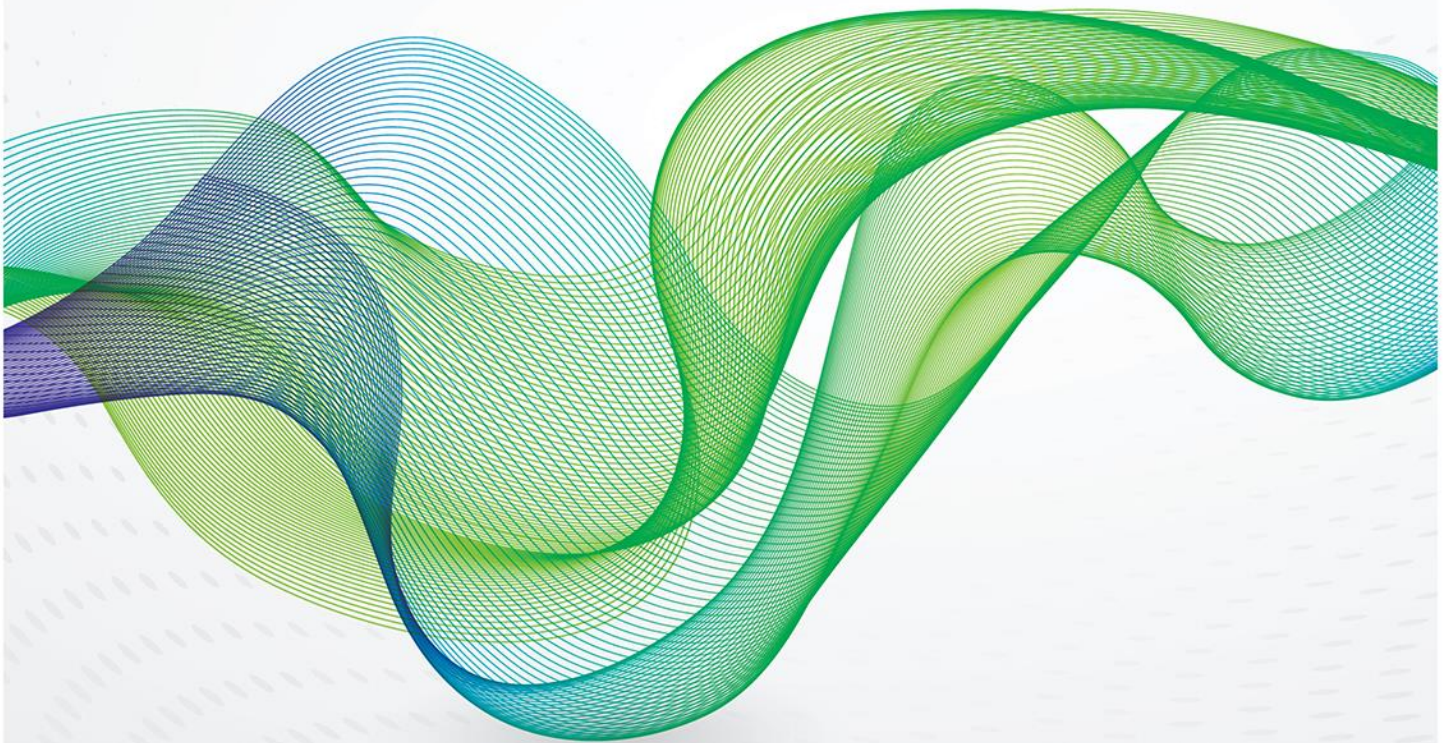




THE OXFORD
INSTITUTE
FOR ENERGY
STUDIES

April 2016

Asian LNG Demand: Key Drivers and Outlook





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ISBN 978-1-78467-055-9



Preface

The LNG Industry has long regarded the Asian markets of Japan, South Korea, Taiwan, China and India as high growth importing markets, willing to sign long term contracts with price terms linked to crude oil prices. The rebound in Asian LNG demand in 2010, following the post-financial crisis year of 2009, re-affirmed this paradigm with LNG markets further tightening following the Fukushima tragedy. The signal for new LNG supply projects could not have been clearer in 2010 and 2011.

While the LNG supply projects triggered by such high demand growth and price signals were being constructed however, Asian demand for LNG began to wane. This appeared to be partly a consequence of mild winters but also LNG import prices and a general regional economic slowdown, perhaps led by China, also contributed.

The somewhat simplistic assumption that Asian markets would always obligingly provide consistently high LNG demand growth has become questionable. Attempting to understand the 'new dynamics' of these markets however is challenging for a number of reasons, including data transparency and consistency, rational energy policies and in many cases the potential impending decline in domestic gas production in some countries.

This paper seeks to provide a 'ground level' understanding of the existing, emerging and potential Asian LNG markets. The OIES Natural Gas Programme always seeks to anticipate new trends in the global gas 'system' and this paper represents an assessment of the potential high growth LNG markets of the future which may require a new response from the upstream industry.

James Henderson

Oxford April 2016



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Glossary

ACQ	Annual Contract Quantity
bcf	Billion cubic feet
bcf/d	Billion cubic feet/day
bcm	Billion cubic metre
bcma	Billion cubic metres/annum (year)
bcm/year	Billion cubic metres/year
bn	Billion meaning 1000 million or 10 E9
\$	US\$
\$/MMBtu	Value of LNG expressed as US\$ per million Btu
E&P	Exploration and Production
EIA	US Energy Information Administration
FID	Final Investment Decision
Gas Storage	The storage of natural gas in either underground structures such as depleted oil or gas reservoirs, salt caverns or aquifers, or alternatively as LNG either in storage tanks at regasification terminals or LNG Peak Shaving facilities.
GHG	Greenhouse gas
GIIGNL	Groupe International des Importateurs de Gaz Naturel Liquéfié (International Group of Liquefied Natural Gas Importers)
Henry Hub	The pricing point for natural gas futures contracts traded on NYMEX. It is a point on the natural gas pipeline system in Erath, Louisiana where it interconnects with nine interstate and four intrastate pipelines. Spot and future prices set at Henry Hub are denominated in \$/MMBtu and are generally seen to be the primary price set for the North American natural gas market
HoA	Heads of Agreement
Hub	The location, physical or virtual, where a traded market for gas is established
IEA	International Energy Agency
JCC	Japan Customs-Cleared Crude Oil price –the average price of customs-cleared crude oil imports into Japan – formerly the average of the top 20 crude oils by volume as reported in customs statistics; nicknamed the ‘Japanese Crude Cocktail’. It is the commonly used price formation mechanism in long-term LNG contracts in Japan, Korea, and Taiwan.
Kl	1,000 litres
kWh	Kilowatt hour
Liquefaction Plant	A large scale processing plant in which natural gas is cryogenically cooled to minus 161° Celsius where it becomes a liquid at atmospheric pressure.



mmcm	Million cubic metres
mcm	Thousand cubic metres
MMBtu	Million British thermal units
MOU	Memorandum of Understanding
mt	Million tonne
mtoe	Million tonnes of oil equivalent
mtpa	Million tonnes per annum
MW	Megawatts
MWh	Megawatt hours
NGLs	Natural gas liquids
Oil-Indexed Gas Prices	Gas prices within long-term contracts, which are determined by formulae containing rolling averages of crude oil or defined oil product prices
Regasification	The process of reinstating LNG to a gaseous state for injection into a distribution system for end-user consumption.
Reserves	The amount of gas underground that can be commercially recovered
Short term LNG	An LNG cargo (or series of cargoes) sold under contract(s) of less than four years duration
Spot LNG	Single cargo of LNG sold outside of a term contract
tcf	Trillion cubic feet
tcm	Trillion cubic metres
TOP	Take-or-pay (or 'minimum bill'), the quantity of gas which, during a gas contract year, the buyer is obliged to pay for regardless of whether it physically takes the gas.
Upstream	Facilities including drilling, well completion and gas gathering to supply the feed gas the liquefaction plant



Introduction

The research for this paper was undertaken to produce a substantive part of a chapter on Asian LNG markets for the OIES-KAPSARC book 'LNG Markets in Transition – the Great Reconfiguration', to be published in September 2016. This paper includes country-level detail and analysis which could not be included in the book chapter due to space constraints, however it is important to make such analysis available to researchers and analysts following Asian LNG markets and to highlight data sources from in-country government departments, often overlooked from a European or North American perspective.

Although not the first markets to receive LNG, Japan, South Korea, Taiwan and more latterly China and India have dominated the LNG import picture in recent times. It could be argued that the spectacular (and largely unforeseen) rebound of Asian LNG demand in 2010 of some 18% (over 2009) in these markets, together with higher oil-indexed LNG contract prices and the tightening of the LNG spot market after the Fukushima tragedy, were the market signals which spurred the wave of FIDs for LNG supply projects which have or will come on-stream in the 2015 – 2020 period. Expectations of demand growth trends extrapolated from the early 2010s, however, were largely undermined prior to the completion of these projects. In addition to recent mild winters, China's transition to the 'new normal' and a wider slowdown in economic growth has significantly reduced LNG demand compared to prior expectations. With some 170 bcm/y of new LNG supply due to come on-stream prior to 2020, the uncertainty over the future Asian LNG demand trajectory is a fundamental component impacting the global 'LNG-connected system'. LNG produced (at very low variable cost), but not required, by Asian markets will, at the margin, find a home in Europe which has some 200 bcm/y of regas capacity, currently only utilised at 25%. The potential for, and consequences of, competition with Russian pipeline gas in the European gas market have been discussed extensively in Rogers (2015) and Henderson (2016).

Leaving aside the wider consequences of future LNG balances and trade-flows discussed in these publications, this paper focusses on the Asian LNG importing markets. The key research questions addressed for each importing country are:

- How important is gas in the energy balance and how has this evolved by sector in the past decade or so?
- What is the outlook for future gas demand, given government energy policy, economic growth outlook and other factors specific to the country in question?
- Given the competing sources of gas supply and their specific demographics, what is the outlook for LNG import requirements?
- Taking the Asian LNG importers as a group, what are the key drivers of LNG demand growth and what is the likely range (i.e. low and high outlooks)?

To address these questions the paper divides the Asian LNG markets into those classified as 'mature' – Japan, South Korea and Taiwan (Chapter 1); and those termed 'more recent and emerging' – China, India, Singapore, Thailand, Indonesia, Malaysia, Pakistan, Bangladesh and Vietnam (Chapter 2). Each is assessed with the above research questions in mind. Where possible the author has used in-country sources to build an understanding of each market. Chapter 3 provides the summary and conclusions.

It is hoped that the paper provides insight and at least a framework for analysing and monitoring these markets which, if not currently deemed to offer the high levels of future LNG demand anticipated from the standpoint of the early 2010s, will nevertheless constitute a key element of the global LNG balance for the foreseeable future. As such they will significantly impact the fundamentals and pricing dynamics of the increasingly 'connected' global regional gas markets.



1. Mature Asian LNG Markets

1.1 Introduction

This section describes the markets generally viewed as the 'mature' Asian LNG importers, namely Japan, South Korea and Taiwan, addresses the factors which have influenced their LNG consumption trends to date and derives views of possible future demand paths. These three markets commenced LNG imports in 1969, 1986 and 1990 respectively. As a group they accounted for in excess of 60% of global LNG imports from 1980 to 2006.

These countries have minimal domestic gas resources and depend on natural gas to differing degrees in their power and non-power sectors. All three markets have enjoyed economic growth based on export-oriented manufacturing and technology goods production, however with the slowdown in Chinese economic growth and the limits to growth inherent in this economic model, there are questions regarding their future economic performance. Japan in particular is struggling to stimulate domestic demand in the face of high personal and corporate savings levels and ongoing deflationary tendencies. Declining population trends are also a relatively new challenge for these countries which threaten domestic consumption growth and workforce renewal.

The largest uncertainty impacting future gas (LNG) consumption trends, however, is the uncertainty in future energy consumption growth and energy mix. With the challenge of GHG emission reduction, especially post COP21, strategies incorporating energy efficiency and renewables have been proposed with nuclear aspirations constrained either by public opinion or (in the case of Japan) re-start logistics and approval processes. While an indicative share for gas in the energy mix is often included in policy documents, competition with (cheaper) coal in the power sector is an open issue which requires a more robust policy framework than generally exists at present. Typically the continued presence of coal in the energy mix is offset by assumed future energy efficiency gains and aggressive renewable capacity growth. The reality of such aspirations will presumably become clear once National Determined Contributions agreed at COP21 are tracked by the Monitoring, Reporting and Verification process, albeit from 2020 at the earliest¹.

The following sections describe the individual markets with the objective of addressing the drivers of future LNG demand. With this as the primary focus, it is inappropriate to dwell on the details of individual LNG contracts and import infrastructure. For such information the reader is directed to GIIGNL which provides an annual update on these and other aspects of the LNG market at a country level.

¹ IIGC (2015), pp. 4-5.



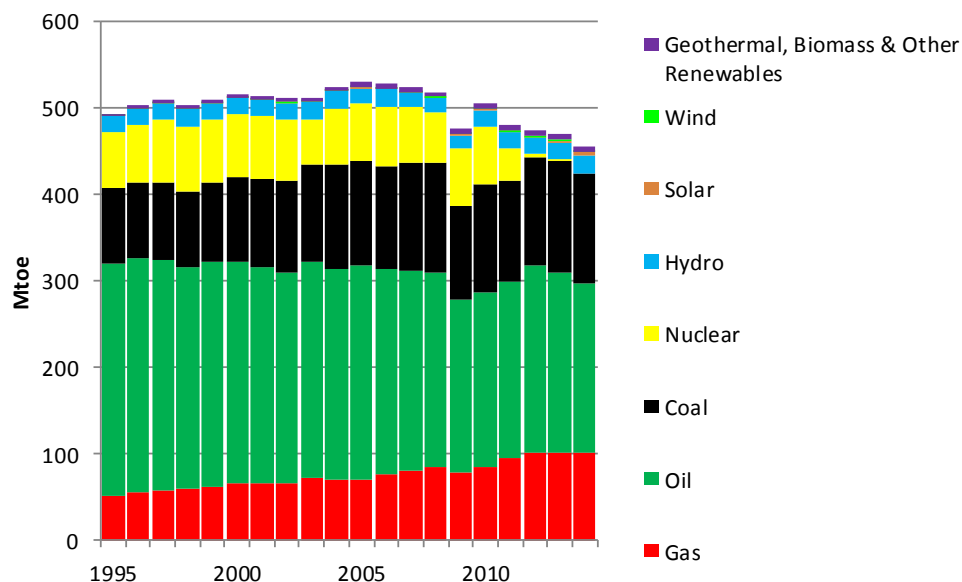
1.2 Japan

1.2.1 Energy Mix

Japan is the world's third largest economy with a population of 126.2 million in 2014², though this is viewed as being in long term decline. Decades of low economic growth and heavy government spending to support the economy have left Japan with the world's highest public debt at almost 250% of GDP. The Abe government in 2012 commenced a three-part plan of stimulus spending, monetary easing and structural reforms. In mid-2015 commentators appeared cautiously optimistic that Japan's growth of 3.9% (annualised) in 1Q 2015³ heralded a sustained recovery after 2014's zero GDP growth. September 2015 GDP data however indicated a 1% annualised growth, consumer spending and investment remaining sluggish and exports dampened by decelerating growth in China⁴. Japan's GDP comprises Agriculture 1.1%, Industry 25.6% and Services 73.2%⁵. Japan's manufacturing sector has a significant element of high energy intensive industries, such as metals, chemicals and machinery manufacture.

Japan's primary energy mix is shown in Figure 1. Total energy consumption reached a plateau in the mid-2000s with gas and coal gaining share from oil and nuclear. The post financial crisis year of 2009 reduced energy consumption from all sources, but 2010 showed a significant recovery. On March 11, 2011 the Great East Japan Earthquake and the resulting Tsunami resulted in a nuclear accident at the Fukushima Daiichi Nuclear Power Station. This led to the policy-induced shutdown of all Japan's nuclear generation plant⁶. The loss of nuclear generation was partially compensated for by an increase in gas, coal and oil-fired generation. 2014 total energy consumption was below the level of 2009.

Figure 1: Japan's Energy Mix 1995 – 2014



Source: BP (2015)

² 'Japan's population slide set to accelerate', FT, July 2nd, 2015, <http://www.ft.com/cms/s/0/41aace5e-208f-11e5-aa5a-398b2169cf79.html?siteedition=uk#axzz3fr7DgV1U>

³ 'Japan economy grows 3.9% in first quarter', FT, June 8th 2015, <http://www.ft.com/cms/s/0/6a1ae4a0-0d89-11e5-b850-00144feabdc0.html#axzz3frCyYjrF>

⁴ '2016's economic outlook' The Japan Times, 11th January, 2016, <http://www.japantimes.co.jp/opinion/2016/01/11/editorials/2016s-economic-outlook/#.VpYtThWLSCo>

⁵ CIA (2015b)

⁶ For a comprehensive review of the impact of Fukushima see Miyamoto, A., Ishiguro, C. & Nakamura, M, (2012)

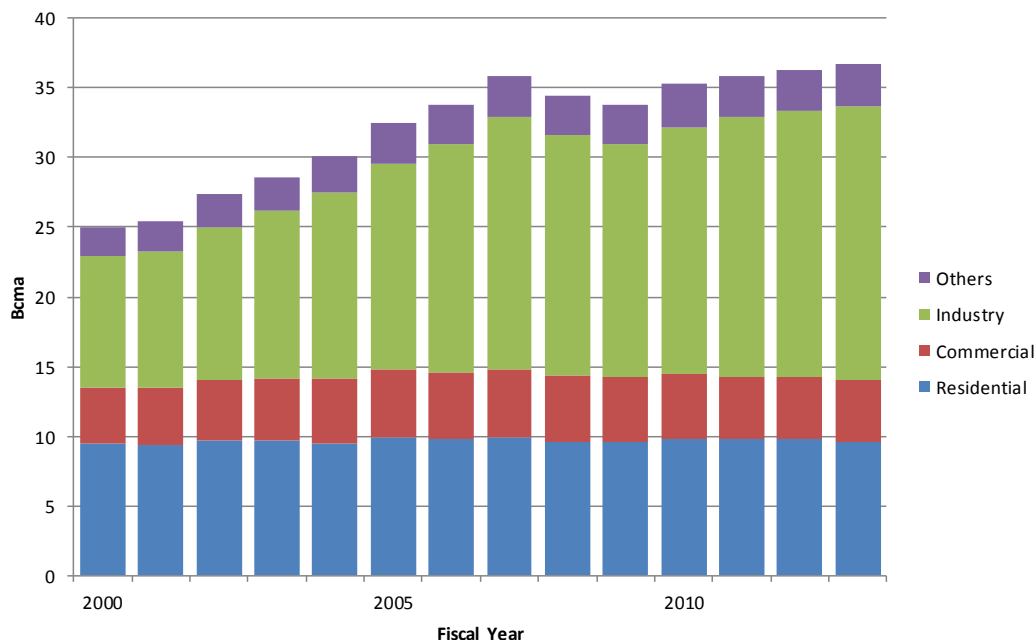


1.2.2 Gas Consumption, Energy Policy and Future Outlook

Japanese gas demand has a space heating seasonal peak in winter (peak month generally February) and a less pronounced peak in summer, due to additional power generation usage for air conditioning⁷. Japan manages seasonal demand fluctuations by varying the stock of LNG held in storage tanks at regas terminals and by increasing the frequency of cargo deliveries during high demand periods.

City gas consumption became increasingly dominated by the industrial sector through the 2000s with the residential and commercial sectors having remained stagnant from 2000 (Figure 2). The average annual growth rate in industrial sector gas consumption was 10 % from 2000 to 2007, slowing to 2.6 % from 2008 to 2013.

Figure 2: Japan City Gas Consumption – 2000 – 2013 (Fiscal Years)



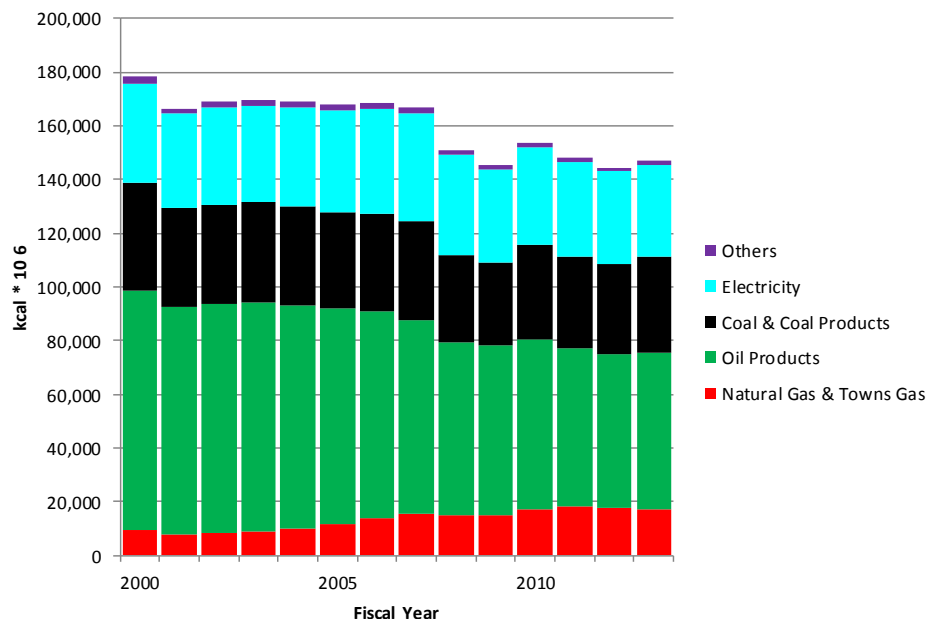
Source: IEEJ (2015a), P 184

Note: The Japanese Fiscal year runs from April to March of the following year. Fiscal Year 2013 ends in March 2014.

⁷ Miyamoto, A. (2008), Figure 4.1, P 127.



Figure 3: Japan Industry Sources of Energy FY 2000 - 2013



Source: IEEJ (2015a), P 68

In FY 2013 gas accounted for only 11.6% of industry sector energy, growing from a much lower base in the early 2000s (Figure 3). Industrial energy consumption has reduced considerably since FY 2007. In general gas has gained share from oil products but coal consumption has grown.

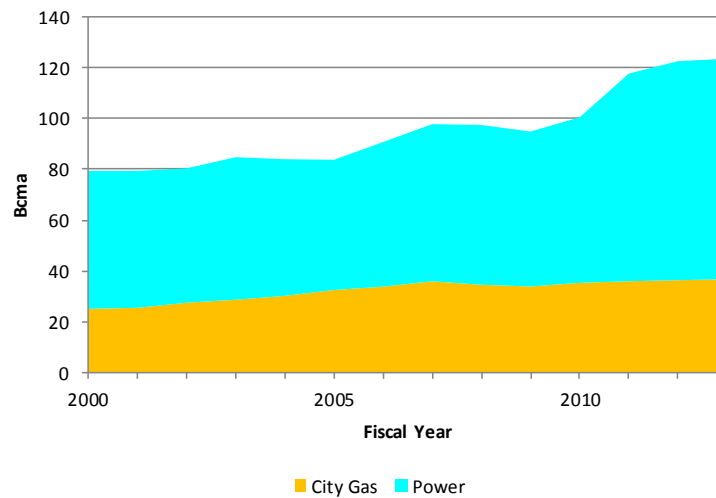
The scope for further future growth of gas in the industrial sector was addressed in a 2012 OIES paper⁸ where the importance of access to gas (infrastructure) and price competitiveness relative to other fuels were viewed as key determinants of future consumption growth. The authors concluded that industrial demand would continue to grow at 2.85% pa to 2020, but that residential demand would reduce by 0.57% pa and the commercial sector grow at 0.42%p.a.; with an aggregate city gas sector growth of 1.6%pa.

Figure 4 demonstrates the scale of gas consumption in the power sector relative to that of city gas as discussed above.

⁸ Miyamoto, A., Ishiguro, C. & Nakamura, M, (2012)



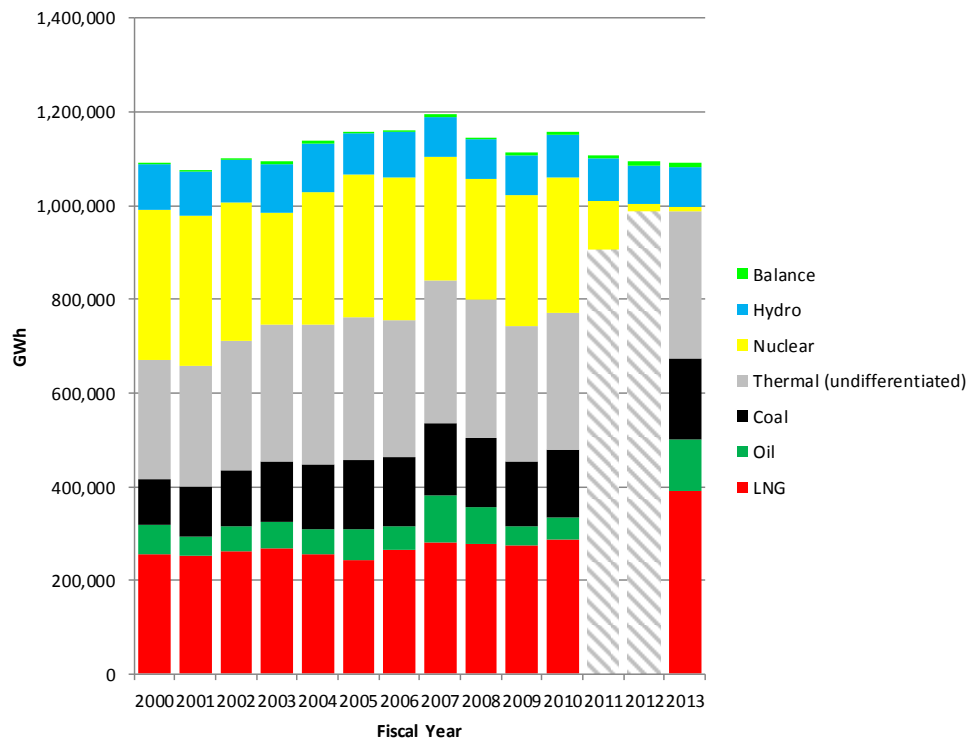
Figure 4: Japan Gas Consumption in Power and City Gas Sectors FY 2000 - 2013



Source: Produced from a balance derived from IEEJ (2015a), pp. 178, 180, 184

Gas consumption in the power sector remained reasonably constant in the period 2000 to 2006, grew modestly to 2010 and then expanded dramatically by some 20 bcm/y after Fukushima. Figure 5 shows annual power generation from various fuels/technologies. The impact of the Fukushima disaster and subsequent progressive closure of Japan's nuclear fleet is clearly shown.

Figure 5: Japan Power Generation by Fuel/Technology (FY 2000 – 2013)

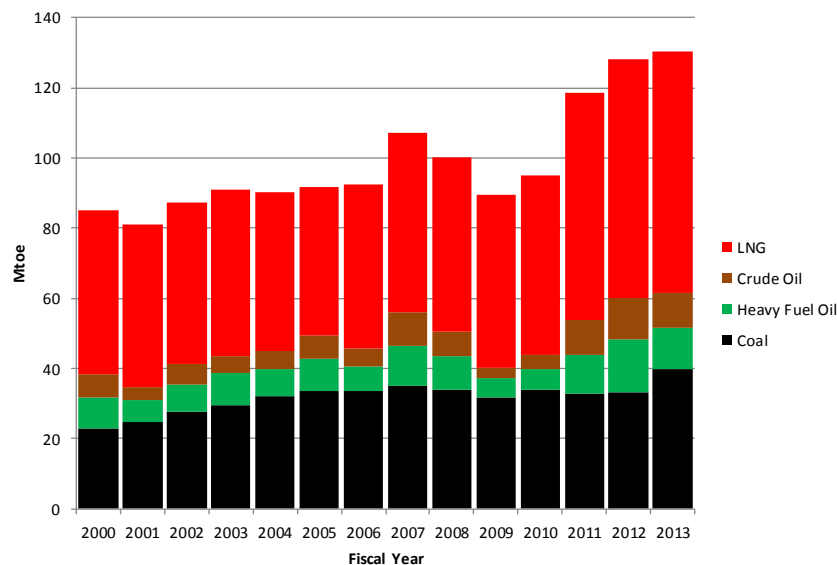


Source: IEEJ (2015a), pp. 196 & 197.

Note: the disaggregated data for LNG, oil, coal and thermal is not available for FYs 2011 and 2012.



Figure 6: Fuel Consumption for Electricity Generation (General Electric Utilities)



Source: IEEJ (2015a), P. 210

Figure 6 shows the consumption of fuels in thermal generation. The graph also enables us to deduce that the loss of nuclear generation post Fukushima was compensated for by broadly comparable increases in crude and heavy fuel oil on the one hand and natural gas on the other.

In July 2011, immediately following the Fukushima disaster, the Energy & Environment Council (Enecan) was established to recommend on Japan's future energy strategy; recommending a phase-out of nuclear power by 2040. Operable reactors would be allowed to restart once they had gained permission from the Nuclear Regulation Authority (NRA), but a 40 year operating limit would be imposed. Enecan proposed a 'green energy policy framework' focused on LNG and coal and an expanded use of renewables. This provoked a strong response from industry with a consensus that a 20 to 25% share of nuclear was necessary to avoid severe economic penalties. The succeeding government (Liberal Democratic Party) abolished Enecan, placing the responsibility for energy policy matters in the hands of METI.

In June 2015 the government's draft plan for electricity generation to 2030 was approved, which has nuclear at 20-22% by 2030, renewables at 22-24%, LNG at 27% and coal at 26% with an aim to reduce CO₂ emissions by 21.9% by 2030 from the 2013 level and to improve energy self-sufficiency measures to 24.3% from 6.3% in 2012⁹. The plan aims to achieve ambitious energy efficiency savings. By 2030 economic growth would normally be assumed to increase energy demand to 411.3 KI (oil equivalent) from the 2013 figure of 361 KI (oil equivalent). Efficiency measures are assumed to reduce this to 326 KI (oil equivalent) by 2030¹⁰.

Achieving these goals will be challenging, however. Early difficulties with renewable expansion surfaced in October 2014 when at least seven of the then major utilities limited the access of renewable energy to their grids due to potential overloads¹¹. Solar capacity tripled in the fiscal year ending in March 2014 due to the high feed in tariff introduced in 2012. Even so, renewables

⁹ 'Nuclear Power in Japan', July 2015, World Nuclear Association, <http://www.world-nuclear.org/info/Country-Profiles/Countries-G-N/Japan/>

¹⁰ IEEJ (2015b), Slide 8.

¹¹ IEEJ (2015b), Slide 8.



(excluding hydro), only accounted for 2.2% of Japan's electricity output in fiscal year 2013¹². Of perhaps greater concern, the energy efficiency goals in the 2015 draft plan assume a similar path to that which was achieved in the period 1970-1990¹³. Achieving this will likely be difficult, Japan being already regarded as the 6th most energy efficient nation in a global survey¹⁴.

The process for re-starting nuclear plant comprises a safety assessment by the NRA and the briefing of local governments by the operators. The NRA process includes the review of detailed design, site inspection and an assessment of operating management systems. Local government consent is required before restart can occur. Kyushu Electric Power Co.'s Sendai 1 began full commercial operations on Sept 10th 2015 and Sendai 2 on Nov 17th¹⁵. These are both 890 MW reactors. By end November both plant had reached full capacity. Kansai Electric Power Co received local approval for the restart of its Takahama 3 and 4 reactors but start-up was delayed until late January and late February 2016 pending preparations for final on-site checks by Japan's Nuclear Regulatory Authority. The court decision to start up the plant was opposed by public opinion. The Ikata 3 reactor gained approval for restart from the Ehime Prefecture on 29th October 2015. The 846 MW reactor was expected to start in early 2016.

There are still uncertainties as to the pace and extent of the nuclear restart process. Of the 42 operable reactors, in October 2015 Reuters reported (based on NRA inspection data, court rulings and interviews with local authorities, utilities and energy exports), that 7 reactors are likely to restart over the next few years (down from 14 in a similar 2014 survey). The fate of the remaining potentially operable reactors appears uncertain¹⁶.

Under a high case scenario developed by Itochu, about 10 reactors could be re-started every year with a total of 35 units back online within five years¹⁷. Delays observed to the process to date seem likely to continue, however.

Assuming (for the purpose of this analysis) Japan's renewable growth and coal and oil power sector constraint ambitions are achieved, the outlook for LNG in the power sector depends primarily on the achievement of energy efficiency goals and the pace of nuclear re-starts.

To explore the sensitivities, the following scenarios for nuclear re-starts were considered:

- Fast Re-start – where Japan achieves 35.45 GW of operational capacity by 2020 which operates at an assumed historic average of 70% send-out (with modest assumed additional efficiency growth to 2030).
- Slow Re-start – where a similar level of nuclear capacity is achieved more gradually – i.e. by 2030.
- Partial Restart – where only 50% of the previous scenario's capacity is achieved.

The trends in nuclear generation for these scenarios are shown in Figure 7.

¹² 'Outlook cloudy for Japan's renewable energy drive', FT, April 20th, 2015, <http://www.ft.com/cms/s/0/dae47c8c-d927-11e4-b907-00144feab7de.html#axzz3g2zv8SI6>

¹³ IEEJ (2015b), Slide 13

¹⁴ 'The International Energy Efficiency Scorecard', ACEEE, <http://aceee.org/portal/national-policy/international-scorecard>

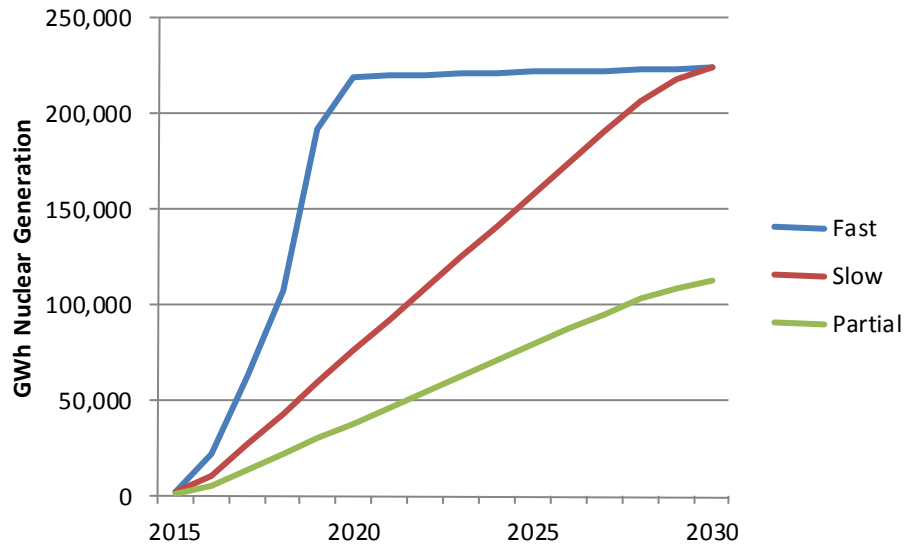
¹⁵ Japan Nuclear Update, Nuclear Energy Institute, December 15th 2015. <http://www.nei.org/News-Media/News/Japan-Nuclear-Update>

¹⁶ 'Japan Nuclear Power Outlook Bleak Despite First Reactor Restart'. Reuters Sept 1 2015 <http://www.reuters.com/article/us-japan-nuclear-restarts-analysis-idUSKCN0R022Q20150901>

¹⁷ 'Nuclear Power in Japan', July 2015, World Nuclear Association, <http://www.world-nuclear.org/info/Country-Profiles/Countries-G-N/Japan/>



Figure 7: Japan Nuclear Re-Start Scenarios



Source: Author's Assumptions

Six scenarios were constructed by combining the three nuclear restart cases with two power generation energy efficiency cases ('No Efficiency saving'; 1,278 GWh power generation in 2030 with 21 % nuclear on the 'Fast Re-start assumption', 23 % Renewables, 26 % Coal, 3 % Oil and 27 % LNG ¹⁸) and a Target Efficiency Saving case with the three nuclear start-up assumptions.

The considerable variation in gas consumption in power generation for these cases is shown in Figure 8.

The future gas demand outlook for Japan in aggregate is shown in Figure 9. Note that the 2030 figure of 62 mtpa (84 bcma) of LNG imports is consistent with the Japanese high energy efficiency scenario described above is met only by two of the cases in Figure 9. Despite the potential for some demand growth by 2020 (due to a slow or partial nuclear restart pace) the overall outlook is one of limited scope for significant gas demand upside, at least based on the assumptions presented here. It should also be noted that higher than average temperatures in the 4th quarter of 2015 suppressed space heating demand which contributed to a decline in 2015 consumption compared to 2014¹⁹.

¹⁸ 'IEEJ (2015b), Slide 9

¹⁹ 'Japan's imports of liquefied natural gas reached 85.05 million mt in 2015, a drop of 3.9 percent as compared to the year before', LNG World News, January 25th 2016, <https://www.lngworldnews.com/japans-annual-lng-imports-drop-for-first-time-in-six-years/>

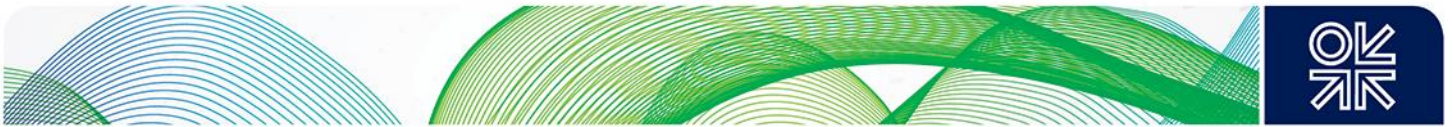
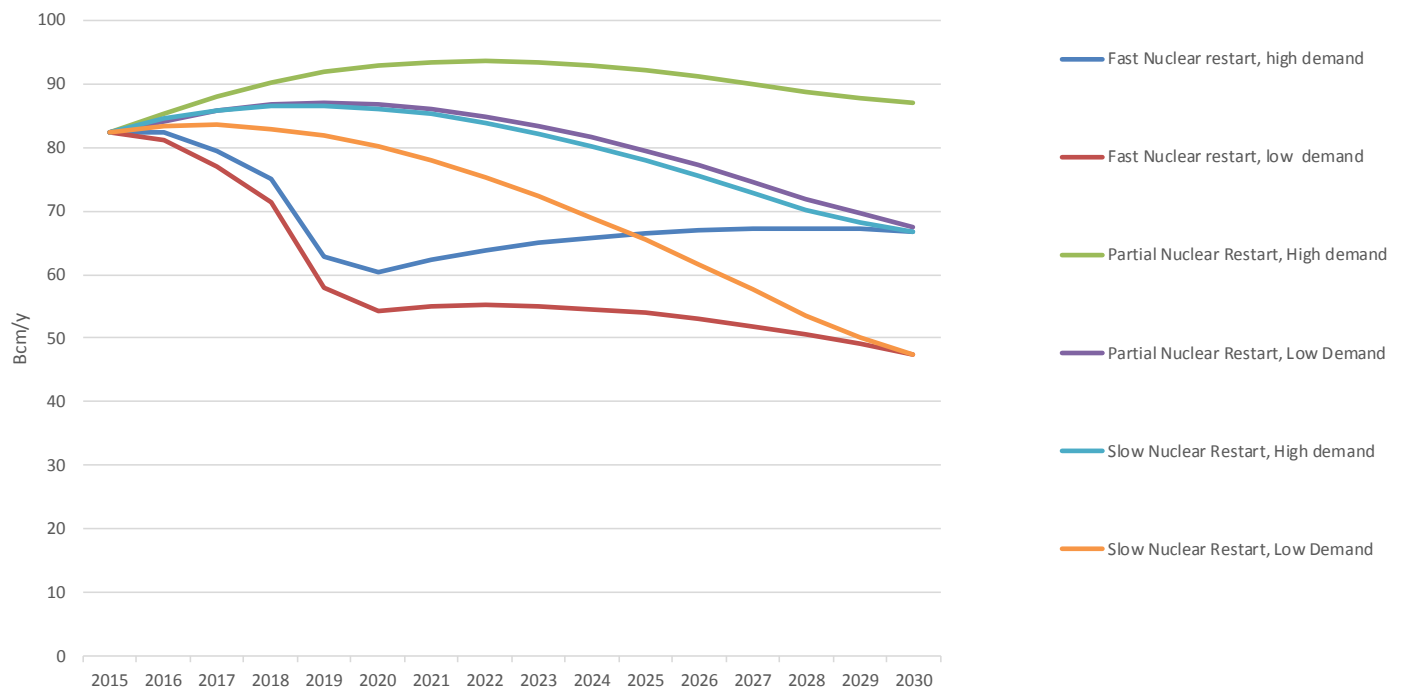


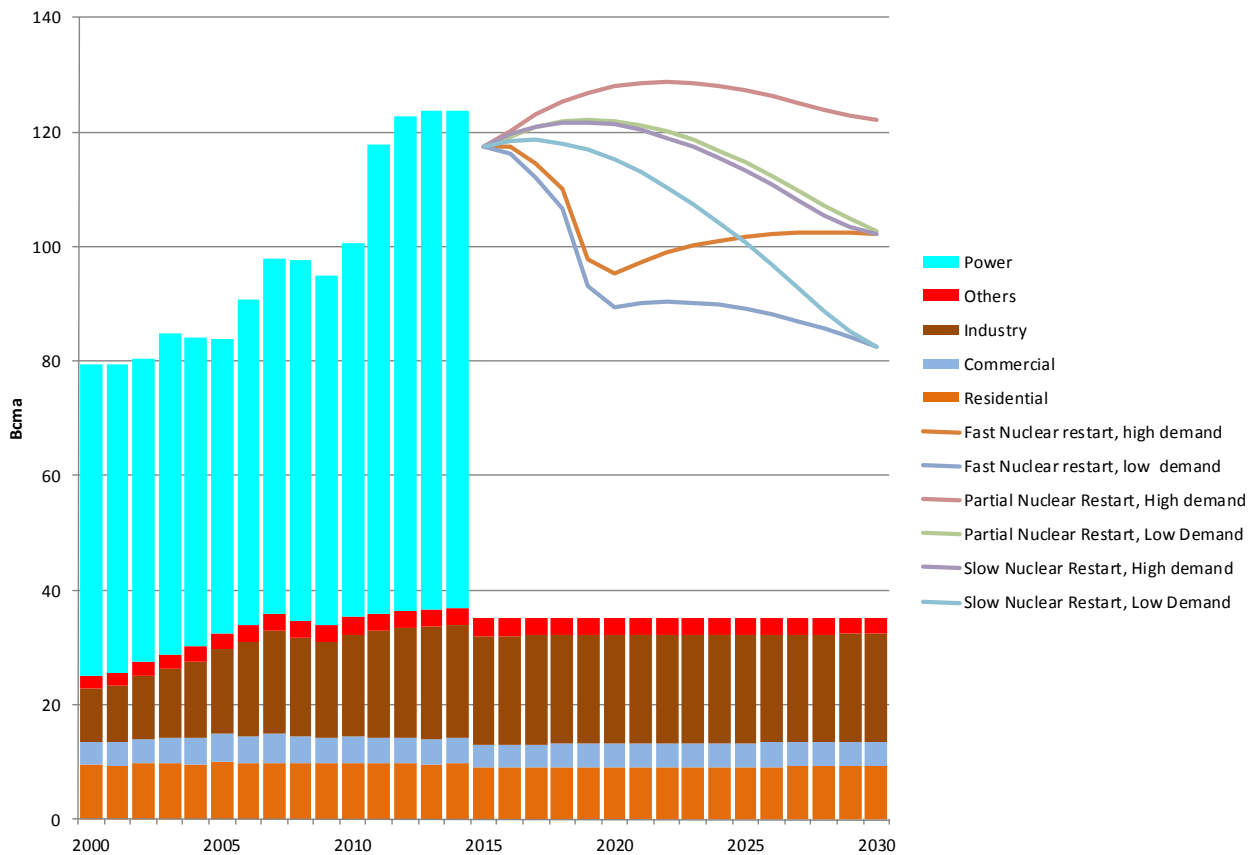
Figure 8: Future Power Generation Gas Consumption for Six Cases



Source: Author's Calculations



Figure 9: Historical and Future Japan Gas Demand



Sources: Produced from Balance derived from IEEJ (2015a), pp. 178, 180, 184 & Author's Analysis

1.2.3 Gas Supply

Japan has some 3.2 bcma of associated and non-associated domestic gas production from numerous small fields. Gas production peaked at 3.73 bcma in FY 2007 and is in slow decline. Japan also produces minor volumes of synthetic gas, (in FY 2012 1.4 bcma), from petroleum (and until 2008) from coal²⁰. Overwhelmingly, however, Japan relies on imported LNG (Figure 10). It has 33 regas terminals with an aggregate capacity of 267 bcma²¹, however, limits on the number of vessels entering Tokyo Bay (under an agreement with the fishing industry), a ban on night time navigation and possibly transmission system constraints appear to limit annual imports to around half of the nameplate capacity stated here²². Regas capacity is driven by peak rather than average demand, Japan having minimal geological gas storage capacity.

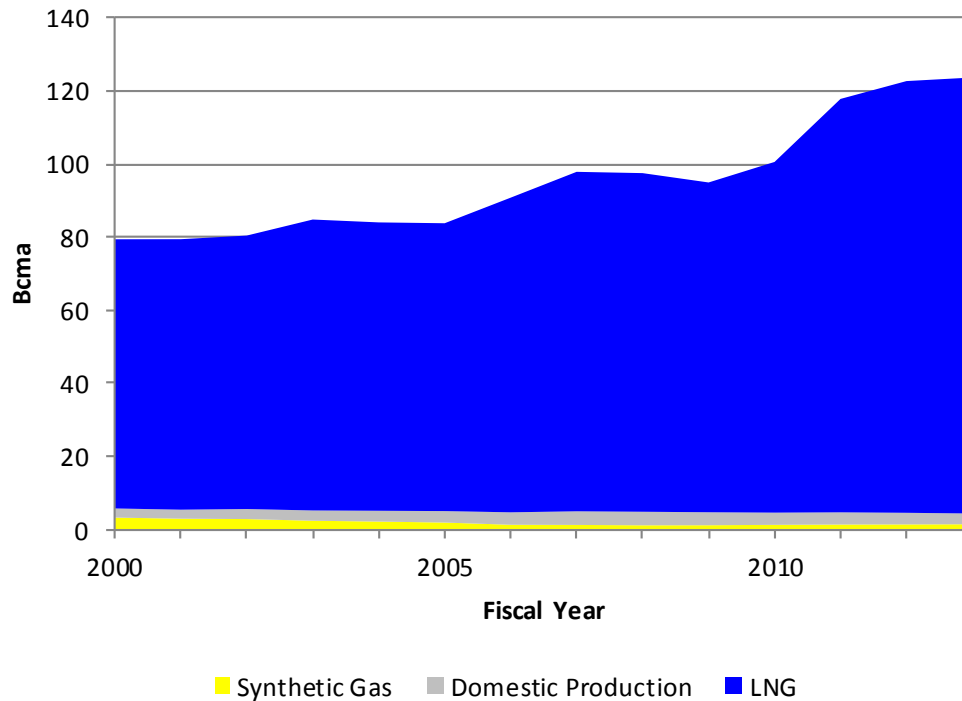
²⁰ IEEJ (2015a), P. 180

²¹ GIIGNL (2014).

²² For example see 'Energy in Japan', 26 April 2012, Credit Suisse, https://doc.research-and-analytics.csfb.com/docView?sourceid=em&document_id=x446745&serialid=vPH7BrABSVBiMmvPrelYc4%2F6gyIbeVxKu8MBtpsV5G4%3D



Figure 10: Japan Synthetic Gas, Domestic Production and LNG Imports



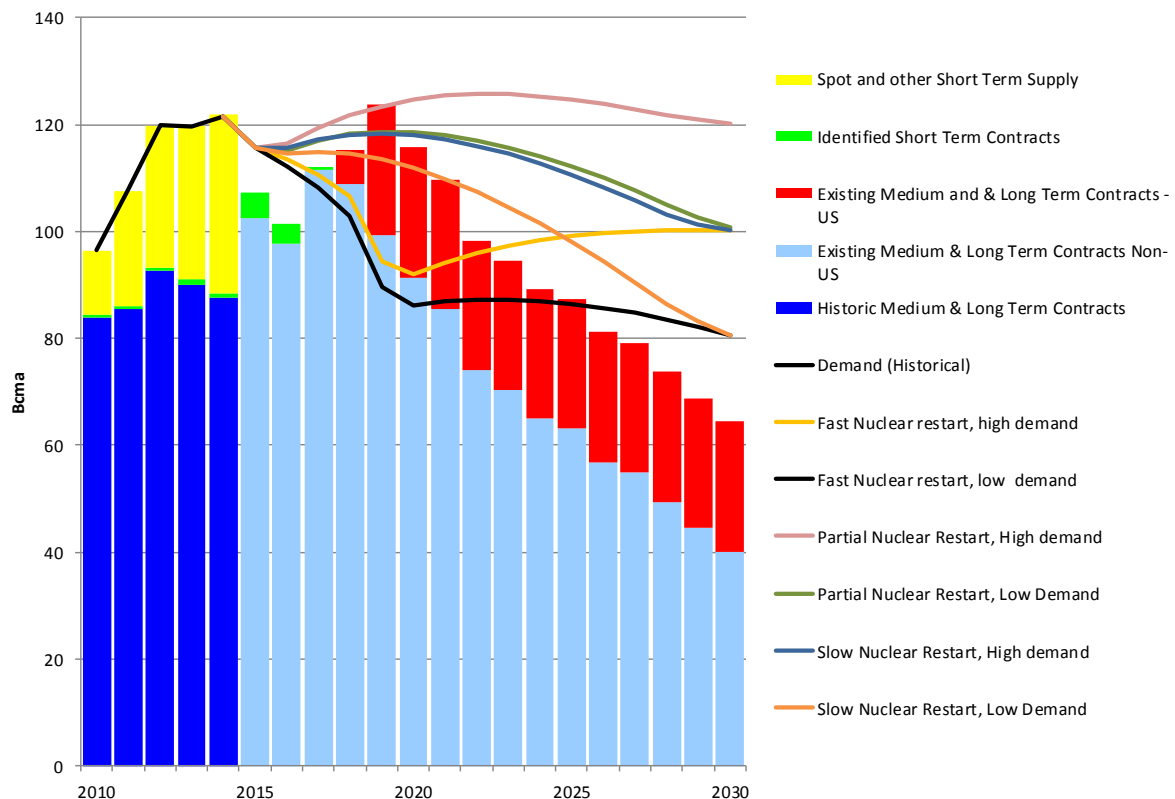
Sources: Produced from Balance derived from IEEJ (2015a), pp. 178, 180, 184 & Author's Analysis

Japan's most significant LNG suppliers, in volume terms are: Qatar, Australia, Malaysia and Russia; however the portfolio is diversified and there are several other suppliers.

Given the uncertainty over future demand, particularly in the power sector given the variable rate and extent of future nuclear re-starts, it is instructive to look at Japan's contracted LNG supply position (Figure 11) superimposed on the demand scenarios developed above. For 2010 to 2014 the yellow bars represent historical volumes purchased on spot or other short term arrangements. These volumes increased significantly post Fukushima. The green bars represent disclosed short term contracts (term equal to or less than four years), some of which proceed beyond 2014. Dark blue represents historical supplies purchased under medium and long-term contracts. Light blue represents the future volumes committed to under medium and long term contracts (ACQs) in force from non-US sources and red from US LNG export facilities.



Figure 11: Japan's LNG Supply Outlook and Demand Uncertainty 2010-2030



Sources: Author's Analysis

Figure 11 suggests that Japan's future contracted LNG position, is manageable at least to the early to mid-2020s over the range of the future demand cases derived above. In the fast nuclear restart cases, Japan has limited exposure to non-US long term contract commitments above its demand requirements. This could be managed by exercising contract downward tolerance in its LNG contracts in the 2018 to 2020 period. Its US LNG contract commitments by nature are destination flexible, however in the fast nuclear restart cases, Japan would need to develop a strategy to 'trade-on' these volumes in what may be a low priced market (in terms of European hub and spot LNG prices). In the slow and partial nuclear restart scenarios, Japan could continue to balance its LNG import requirements using spot LNG cargoes to the early 2020s before possibly needing to sign up new medium or long term contracts.

1.2.4 Japan – Conclusions

Japan is the world's largest LNG importer with gas in 2014 representing some 22% of its primary energy mix. It is an industrialised economy which has suffered from low growth since the early 1990s. Its economic prospects began to tentatively improve in 2015 following intense government policy aimed at economic stimulus, however prospects for sustained recovery are still in doubt. Longer term its low birth rate and population decline emphasise the need for exports rather than domestic consumption to provide a key element of economic growth.

Japan's energy policy has since 2011 been overshadowed by the aftermath of the Fukushima disaster which required increased imports of LNG, crude and oil products to offset the loss of nuclear generation at a time of historically high oil and LNG contract and spot prices. LNG provided some 50% of the additional power generation necessary to offset the loss of nuclear. Future LNG demand will be directly influenced by the pace and extent of the nuclear re-start programme – which seems at present subject to uncertain delays.



A related and important issue is Japan's Kyoto commitment and its need to reduce its CO₂ emissions by 2020. Nuclear restart will be driven by considerations of safety assurance and political and public approval issues at the prefecture level. A slow or partial restart will require Japan to focus on renewables growth (whose scale potential may be questionable on the grounds of cost, land availability and infrastructure issues) and the need to reduce the share of coal and oil in industry and power sector consumption. This would provide additional scope for LNG demand growth but is difficult to define at present.

A low and high LNG import requirement case is shown in Table 1.

Table 1: Japan Low and High LNG Import Cases

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	96.4	107.6	119.8	119.7	121.4	115.7	112.3	108.3	102.9	89.6	86.0	86.9	87.3	87.3	87.0	86.5	85.7	84.7	83.5	82.2	80.6
	High Case	96.4	107.6	119.8	119.7	121.4	115.7	116.3	119.4	121.8	123.5	124.6	125.4	125.7	125.6	125.3	124.7	123.9	122.8	121.7	120.8	120.3
mtpa	Low Case	70.9	79.1	88.1	88.0	89.2	85.1	82.6	79.6	75.7	65.9	63.3	63.9	64.2	64.2	64.0	63.6	63.0	62.3	61.4	60.4	59.3
	High Case	70.9	79.1	88.1	88.0	89.2	85.1	85.6	87.8	89.5	90.8	91.7	92.2	92.4	92.4	92.1	91.7	91.1	90.3	89.5	88.8	88.4

Note: The Low Case corresponds to the Fast Nuclear Restart, Low Power Demand scenario; the High Case corresponds to the Partial Nuclear Restart, High Power Demand scenario.

1.3 South Korea

South Korea in the 1960s had a GDP per capita comparable with the poorer countries of Africa and Asia. Since then it has generally enjoyed strong economic growth and increasing global integration to become a high technology industrial power; currently the world's 12th largest economy. South Korea's export oriented economy was hit by the 2008 global economic crisis but rebounded swiftly with GDP growth in 2010 reaching 6.3%. Since 2010 growth has been muted due to economic and export market slowdowns in the USA, China and the Eurozone, requiring a refocus away from exports towards domestic oriented industry and services. Longer term challenges include an aging population, inflexible labour market and the dominance of large conglomerates/incumbents²³.

The relative contributions of agriculture, industry and services to South Korea's economy were 2.6%, 39.2% and 58.2% in 2013.²⁴ Industries include textiles, steel, shipbuilding, car manufacturing and electronics. South Korea has pursued a strategy of being a 'fast follower', with the government taking on foreign loans and allocating capital to strategic industries, which led to a massive influx of foreign capital goods and turnkey plants. In the 1990s the focus switched from imitating and assimilating mature foreign technologies to in-house R&D, drawing upon emerging new technologies. However, slower growth, reduced job prospects and the deteriorating performances of South Korean companies all indicate that its past strategy is perhaps no longer effective. The government has responded with a new vision labelled the 'creative economy'; generating growth by facilitating cross-fertilisation of IT and other areas²⁵.

Figure 12 shows South Korea's primary energy consumption by fuel. In 2014 gas accounted for 15.7% of the energy mix and was 9% below 2013's consumption levels. Total energy consumption has been essentially flat from 2011, despite the 7% rebound in 2010 after the post-crisis year low in 2009. This is in marked contrast to the period 1999 to 2008 during which energy consumption grew by

²³ 'South Korea', Forbes, December 2014, <http://www.forbes.com/places/south-korea/>

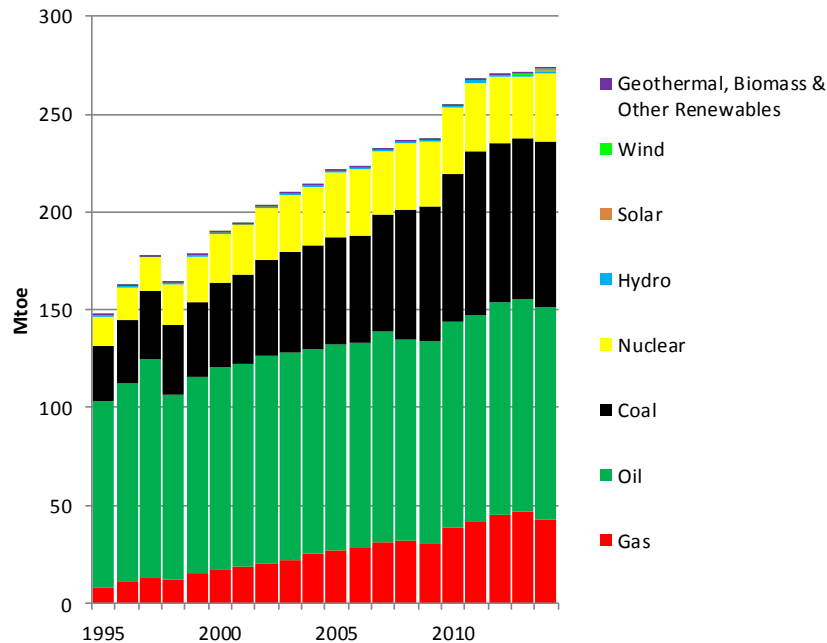
²⁴ CIA (2015b)

²⁵ 'Lessons to be learned from South Korea's stellar rise', Sung Chulchung, February 23rd 2015, Europe's World, <http://europesworld.org/2015/02/23/lessons-learned-south-koreas-stellar-rise/#.VakacPIVhBc>



3%/year on average. While nuclear contributed 13% to the energy mix, this was dominated by coal (31%) and oil (39.5%) in 2014.

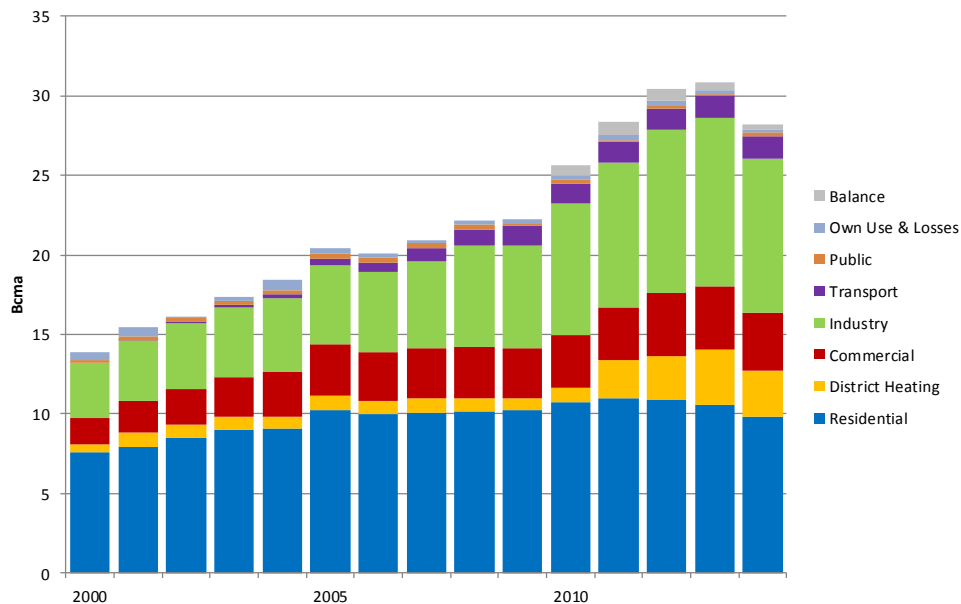
Figure 12: South Korea Primary Energy Mix 1995–2014



Source: BP (2015)

1.3.1 Gas Consumption

Figure 13: South Korea Non-Power Sector Gas Consumption – 2000–2014

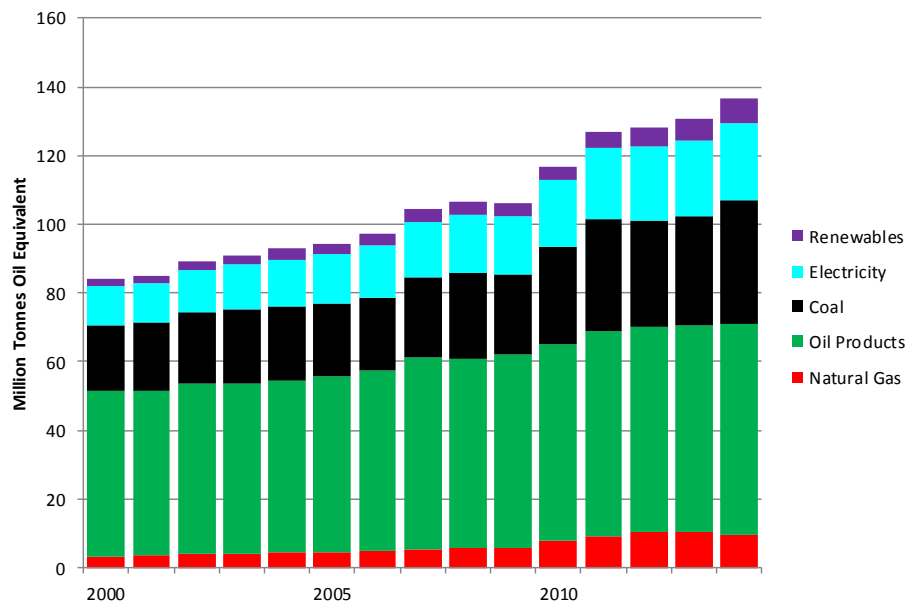


Source: KEEI (2015), pp. 56 -57.

Figure 13 shows that gas consumption in the non-power sectors declined in 2014, partly due to a warm winter. However, growth was significant from 2010 to 2012, both in the industrial and district heating sectors. This said, the proportion of natural gas in total industrial energy consumption is low, as shown in Figure 14.



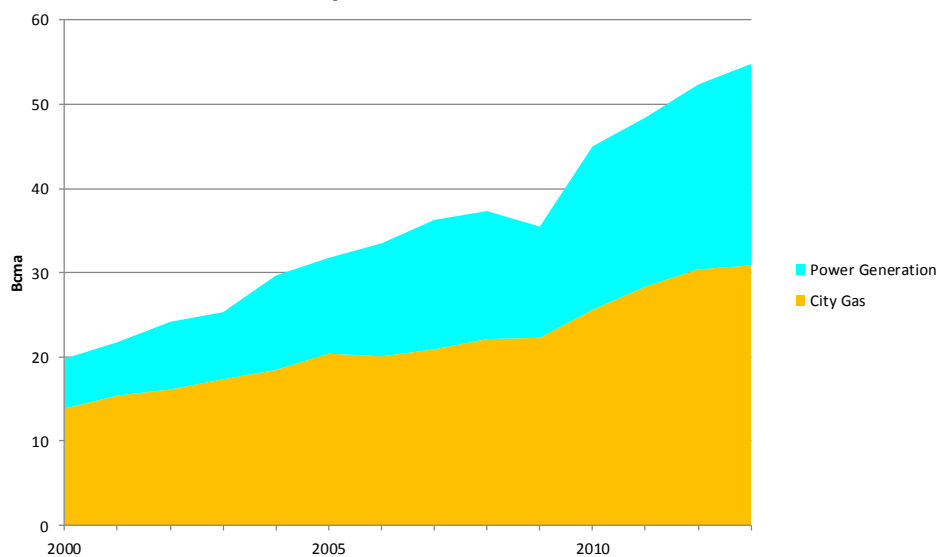
Figure 14: South Korea Industrial Sector Energy Consumption – 2000–2014



Source: Source: KEEI (2015), P. 25.

Gas in industrial use appears to have plateaued at a level of 7 to 8% post 2011, with industrial energy consumption dominated by oil products and coal; the latter having grown significantly since 2009.

Figure 15: South Korea Gas Consumption in Power and Non-Power Sectors 2000-2014

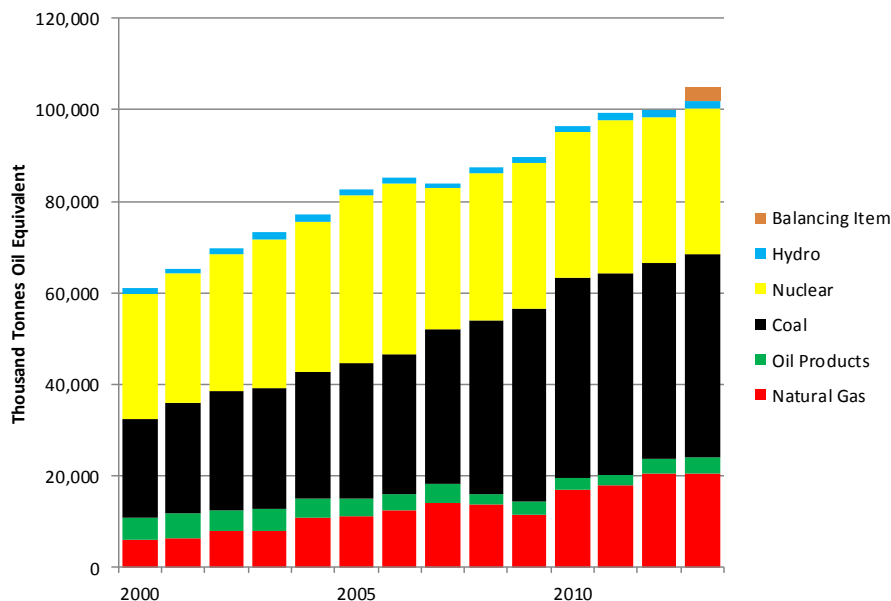


Source: KEEI (2015), P. 56.

South Korea's power sector is less significant relative to other gas consumption sectors (Figure 15). Figure 16 illustrates the minor role played by gas in power generation. Gas has a 20% share in a sector dominated by coal and nuclear.



Figure 16: South Korea Fuel Consumption for Power Generation 2000-2014



Source: KESIS

The growing role played by coal in South Korea's energy mix in the past two decades is reflected in the country's CO₂ emissions which, although having plateaued since 2010 were, in 2014, three times those of 1990. The government's current goal is to achieve a 37% decrease in 'business as usual' GHG emissions by 2030²⁶.

1.3.2 Gas Supply

South Korea's gas supply is overwhelmingly from LNG imports. Domestic production peaked at 0.6 bcm in 2010 and has since declined. After strong growth post 2010, LNG imports declined in 2014 and 2015. Qatar has grown since 2011 to become the dominant source of LNG imports, followed by Indonesia, Malaysia, Oman and Nigeria.

1.3.3 Energy Policy and Future Gas Demand Drivers

President Park Geun-hye's government took power in February 2013. The most recent power sector plan (June 2015) coincided with the cancellation of four new coal-fired plants (total capacity 3.74 GW) with modest future growth in nuclear and gas envisaged. 2029 targets for power generation shares are Nuclear 28.5%, Coal 32.2%, Gas 24.7%, Renewables 4.6%, CHP 5.8% and Oil and Pumped Storage 4.2%²⁷. The envisaged share for gas in 2029 is unchanged from the latest comparable figure from the Korean Energy Economics Institute for 2013. The 2015 plan assumes a minor decrease in coal's share of 2029 power generation relative to 2013's levels with compensating increases in renewables and nuclear. The government expects power demand to grow annually by 2.2%, the World Nuclear Association expects this figure to be 2.8% pa to 2020²⁸. However, this appears to conflict with South Korea's objective of reducing power demand in 2035 by 15% relative to current

²⁶ 'South Korean energy plan sees two more reactors', World Nuclear News, 22nd July 2015, <http://www.world-nuclear-news.org/NP-South-Korean-energy-plan-sees-two-more-reactors-2207154.html>

²⁷ 'UPDATE 1-S.Korea axes four coal plants, plans two new nuclear units', Reuters, June 8th 2015, <http://uk.reuters.com/article/2015/06/08/energy-southkorea-nuclear-idUKL3N0YU0AJ20150608>

²⁸ 'Nuclear Power in South Korea', World Nuclear Association, July 2015, <http://www.world-nuclear.org/info/Country-Profiles/Countries-O-S/South-Korea/>



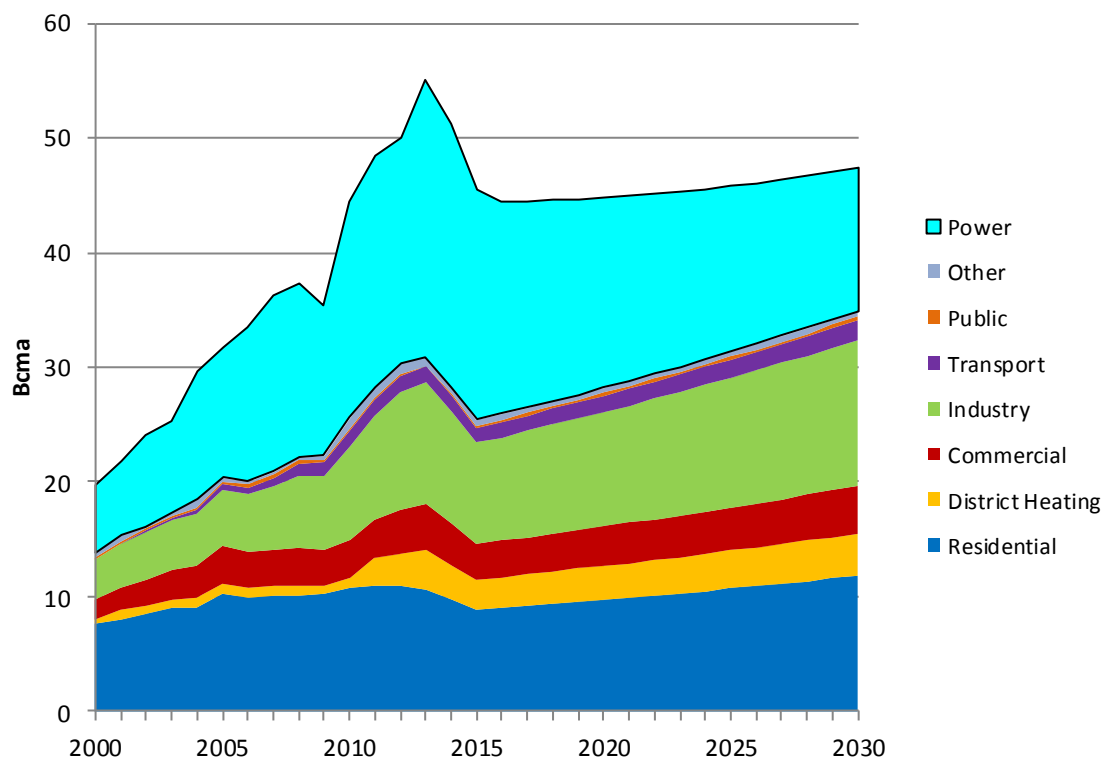
levels (and overall energy demand by 13%), which was stated in its 2014 Energy Master Plan.²⁹ The June 2015 plan was superseded in December 2015 by MOTIE³⁰ who expressed an expectation that demand for gas would drop to 34.65 mtpa in 2029. The use of gas in power generation would fall to 9.48 mtpa and domestic and industrial LNG consumption would rise to 25.17 mtpa³¹. 2015 LNG import data shows a reduction to 45.5 bcm/y from 2014's level of 50 bcm/y due to higher coal consumption and re-start of nuclear power plant temporarily shut down due to safety considerations.

Any outlook of South Korean gas demand must take account of:

- The slowdown in overall energy consumption since 2010, apparently as a result of reduced consumption in South Korea's manufactured goods export markets, and the extent to which this situation may change in the future. This will impact power generation and industrial consumption sectors.
- Consumption trends within the domestic non-power sector, given the outlook for low or negative population growth.
- The assumed rate of power generation growth and the gas share within it. Government messages on this have been conflicting in recent years.

An illustrative outlook is shown in Figure 17.

Figure 17: Historic and Illustrative Future South Korea Gas Consumption



Source: KEEI (2015), Author's Assumptions.

²⁹ MOTIE (2014)

³⁰ MOTIE – Ministry of Trade, Industry and Energy, South Korea.

³¹ 'South Korea's gas demand to drop 5 percent by 2029', LNG World News, December 28th, 2015, <http://www.lngworldnews.com/south-koreas-gas-demand-to-drop-5-percent-by-2029/>



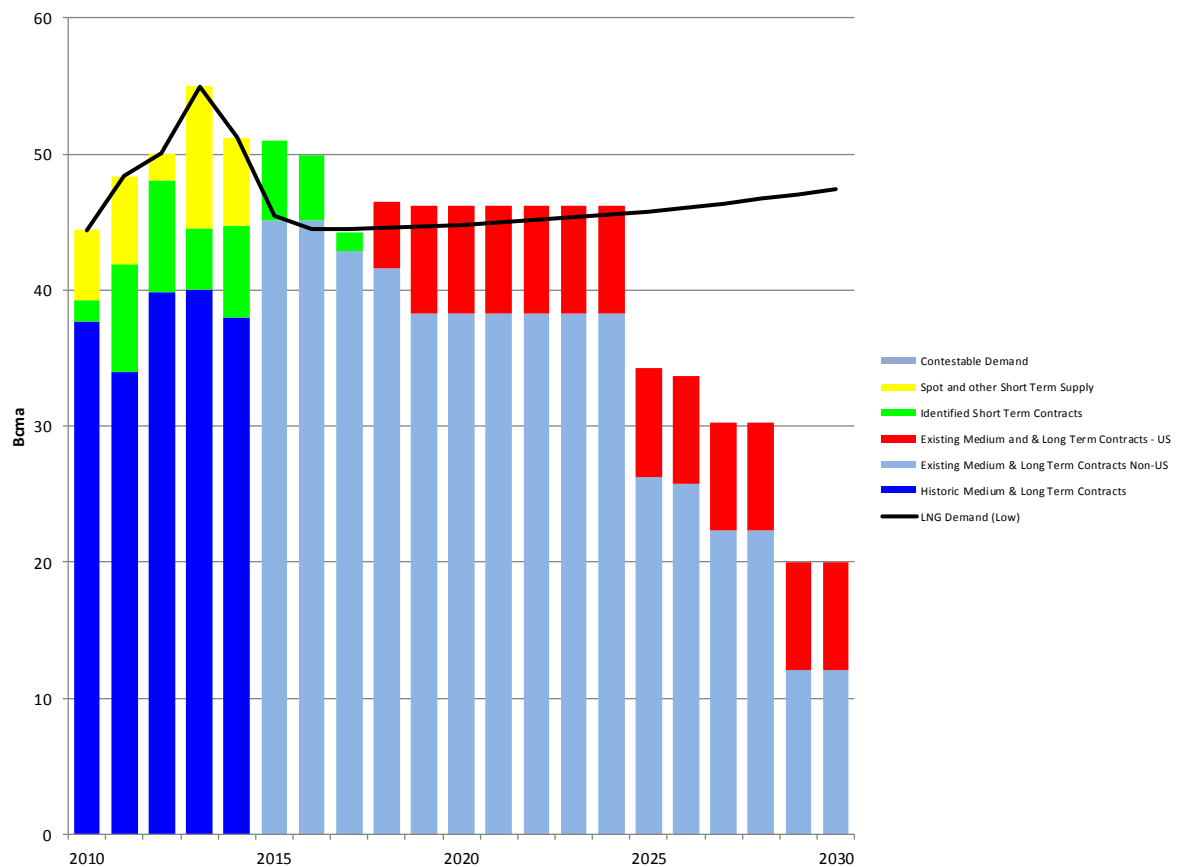
Future annual growth assumptions for specific sectors are:

Residential, District Heating, Commercial: 0.05% p.a.; Transport: 1%; Industry: 0.5%; Power: 2.2%. (Note that 2014 and 2015 sectoral divisions are notional in order to achieve aggregate consumption levels).

Total demand in 2030 amounts to 52.7 bcm compared with 45.5 bcm in 2015.

Figure 18 superimposes the illustrative demand outlook on South Korea's LNG contractual supply position.

Figure 18: South Korea's LNG Supply Outlook and Demand Uncertainty 2010 – 2030



Source: GIIGNL (2014), Author's Analysis

Continued access to spot and short term contractual arrangements should suffice to ensure adequate supply of LNG for South Korea until the early to mid-2020s, although re-sale of short-term contract volumes was required to manage the situation in 2015 and 2016. Post 2025, South Korea will likely seek new supply contracts to offset the sharp decline in its existing portfolio. This will provide an opportunity to change the price formation balance of its supply away from oil indexation if so desired.

1.3.4 South Korea - Conclusions

South Korea is Asia's second largest LNG importer, but with gas in 2014 representing only 15.7% of its primary energy mix. Despite past periods of strong economic growth, the slowdown in the USA, China and the Eurozone has required a refocus away from export industry to domestic-oriented industry and services. Longer term challenges include an aging population, inflexible labour market and the dominance of large conglomerates/incumbents. This is relevant to LNG – which in South Korea is dominated by KOGAS, the world's largest corporate LNG purchaser. With negligible



domestic production, South Korea's gas market development is directly reflected in its LNG import requirements.

South Korea's future LNG demand will be determined by:

- The extent to which it can regenerate economic growth and the balance between energy intensive manufacturing and domestically focussed service industries,
- The need to reduce the role of coal and oil in its energy mix in order to reduce GHG emissions. The extent to which gas plays a role in achieving this is at present uncertain.
- The extent to which the government is able to achieve its future target for nuclear power generation, given a degree of popular opposition to it. In a GHG emission-constrained world this could increase LNG demand.

Despite the rather muted demand outlook, at least compared to historic LNG consumption growth trends, the need for new contracted supplies in the 2020s as existing long term contracts expire, places South Korea (and by definition KOGAS) in the front line of buyer-initiated moves away from JCC-linked contract pricing.

Table 2 shows a high case for South Korean Imports based on the June 2015 power sector plan discussed above, and a low case consistent with MOTIE's revised view of December 2015.

Table 2: South Korea LNG Imports – Low and High Cases

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	44.4	48.4	50.0	55.0	51.2	45.5	44.4	44.5	44.6	44.7	44.8	44.9	45.1	45.3	45.6	45.8	46.1	46.4	46.7	47.1	47.5
	High Case	44.4	48.4	50.0	55.0	51.2	45.5	44.9	45.4	45.9	46.4	46.9	47.4	48.0	48.5	49.1	49.6	50.2	50.8	51.4	52.0	52.7
mtpa	Low Case	32.7	35.6	36.8	40.4	37.6	33.4	32.7	32.7	32.8	32.8	32.9	33.0	33.2	33.3	33.5	33.7	33.9	34.1	34.4	34.6	34.9
	High Case	32.7	35.6	36.8	40.4	37.6	33.4	33.0	33.4	33.7	34.1	34.5	34.9	35.3	35.7	36.1	36.5	36.9	37.4	37.8	38.3	38.7

1.4 Taiwan

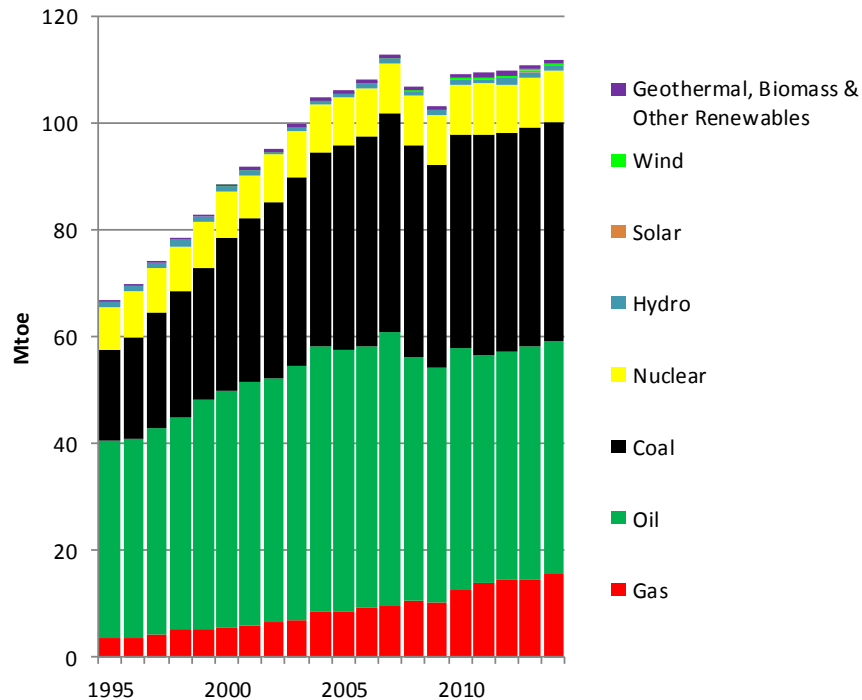
Over the past 50 years the Taiwanese government and private sector have co-operated to continuously enhance industrial competitiveness and achieve steady economic growth. Taiwan has become the global centre for semiconductors, flat panel displays and many other high-tech products. Exports, led by electronics, machinery and petrochemicals provided the impetus for economic development, however this heavy export dependence exposed the economy to fluctuations in world demand. Free trade agreements have proliferated in East Asia in recent years with the Economic Cooperation Framework Agreement signed with China in June 2010 a notable landmark. Taiwan since 2009 has gradually loosened rules governing Chinese investment on the island, and has also secured greater market access for its investors in the mainland. Taiwan's diplomatic isolation, low birth rate, and rapidly aging population are other major long-term challenges³².

Taiwan's energy mix (Figure 19) is heavily dominated by oil and coal (76% combined in 2014 with gas constituting 13.8%). After rapid growth from 1995 to 2007 (4.5%/year), energy consumption growth has been muted following the 2008 financial crisis.

³² CIA (2015a)



Figure 19: Taiwan Primary Energy Consumption 1995-2014

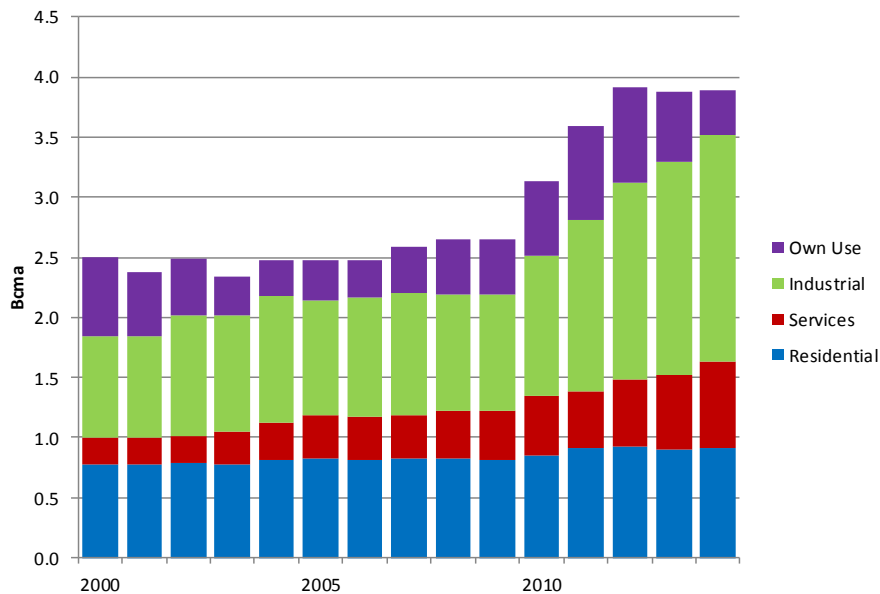


Source: BP (2015)

1.4.1 Gas Consumption

Non-Power (or city gas) consumption is shown in Figure 20. Residential consumption has increased by 2%/year since 2010, but more remarkably industrial and services consumption has risen by 4.8%/year in the same period.

Figure 20: City Gas Consumption by Sector 2000 – 2014

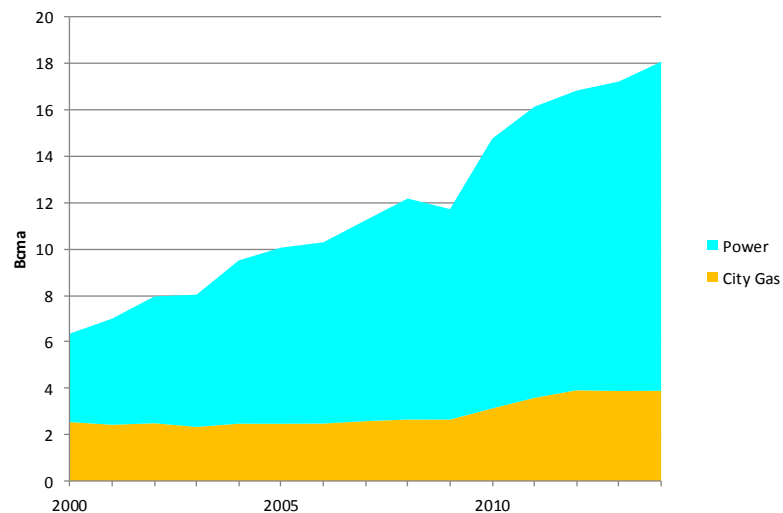


Source: MOEA (2015), pp 69, 75



From Figure 21 it is apparent that Taiwan's use of gas is dominated by the power generation sector, with city gas in 2014 accounting for only 21.5%. Power sector gas consumption surged post 2009, with annual growth from 2010 to 2014 at 5.1%/year.

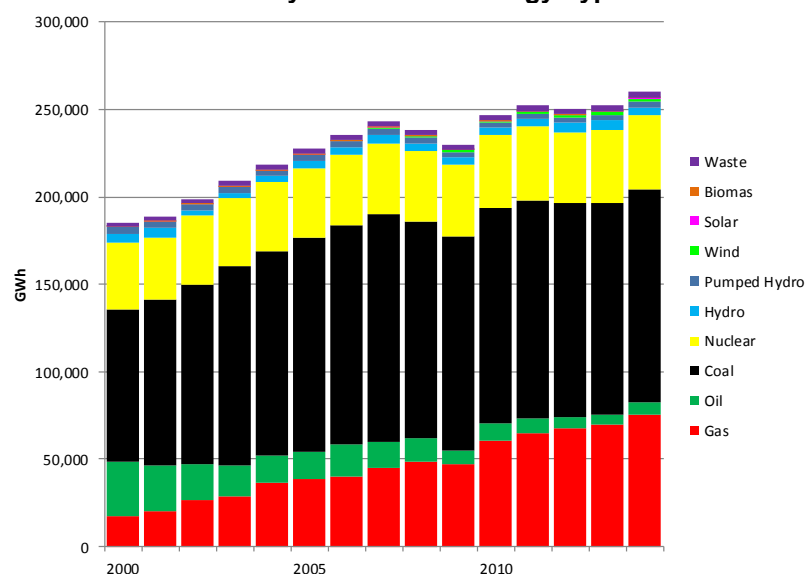
Figure 21: Taiwan Gas Consumption in Power and Non-Power Sectors 2000 - 2014



Source: MOEA (2015), pp 69, 75

This trend is confirmed in Figure 22 which shows power generation by fuel/technology. The growth of gas-fired generation post-2010 has been at the expense of oil and to a lesser degree coal. The growth of coal in the power generation sector and in the energy mix more generally has directly contributed to Taiwan's CO₂ emission profile. Although having plateaued post 2007, Taiwan's 2014 CO₂ emissions are 2.45 times their 1990 level³³.

Figure 22: Taiwan Power Generation by Fuel or Technology Type 2000 - 2014



Source: MOEA (2015), P. 87

³³ BP (2015)



1.4.2 Gas Supply

Taiwan currently has some 0.4 bcm/y of domestic production from nine onshore fields on the western side of the island, and three offshore platforms on the CBK 1-3 gas fields³⁴. The overwhelming source of gas supply is from LNG imports.

Historically Taiwan's main LNG suppliers have been Indonesia and Malaysia. By 2010 the supply portfolio had become diversified with the addition of Qatar, Nigeria, Oman, Australia and others; however by 2014 Qatar grew to represent 45% of LNG imports.

1.4.3 Energy Policy and Future Gas Demand Drivers

Despite Taiwan's economic success, it faces challenges on the energy policy front. Its ambiguous relationship with mainland China and consequently limited international diplomatic relationships, together with minimal domestic energy endowment, have engendered concerns over security of energy supply. Its goals for CO₂ abatement (set in 2008) are to reduce CO₂ emissions to 2008 levels by 2020 and to 2000 levels by 2025³⁵. Taiwan's energy policy focuses on nuclear generation security, energy efficiency, renewables (wind and solar) deployment to reach 16.1% of generation capacity by 2030, a phase out of nuclear and the 'reasonable use of natural gas for security of energy supply'. No mention is made of specifically cutting coal consumption³⁶.

Two major barriers to progress are a) the low domestic price of electricity and gas which has led to a huge cumulative debt on the part of CPC and Taipower³⁷ and does not allow decarbonisation investment costs to be passed on to consumers; and, b) the anti-nuclear public opinion, catalysed by the Fukushima disaster, which has led to the mothballing and suspension of two reactors under construction at the Lungmen nuclear power plant³⁸. The six existing reactors are planned to be phased out between 2018 and 2025.

The outlook for future gas demand in Taiwan critically depends on a) the future growth of power demand and b) the relative shares of gas and coal in power generation (in the context of the intent to phase out nuclear power) and whether policies will emerge to favour gas over coal.

For an assumed future power demand growth of 1%/year, Figure 23 shows a scenario where nuclear is phased out as currently anticipated, wind and solar generation grow at an assumed 20%/year, oil continues to be squeezed, gas grows at an assumed 4%/year and coal supplies the balance. Gas-fired generation continues on its 2000 to 2014 trend, coal increases as nuclear plants are shut down, but due to an assumed continued growth of renewables and gas, by 2030 coal consumption in power is 10% lower than in 2014.

³⁴ 'Energy Profile of Taiwan', Encyclopedia of Earth, October 2007, <http://www.eoearth.org/view/article/152534/>

³⁵ Huang, C. & Ko, F. (2009)

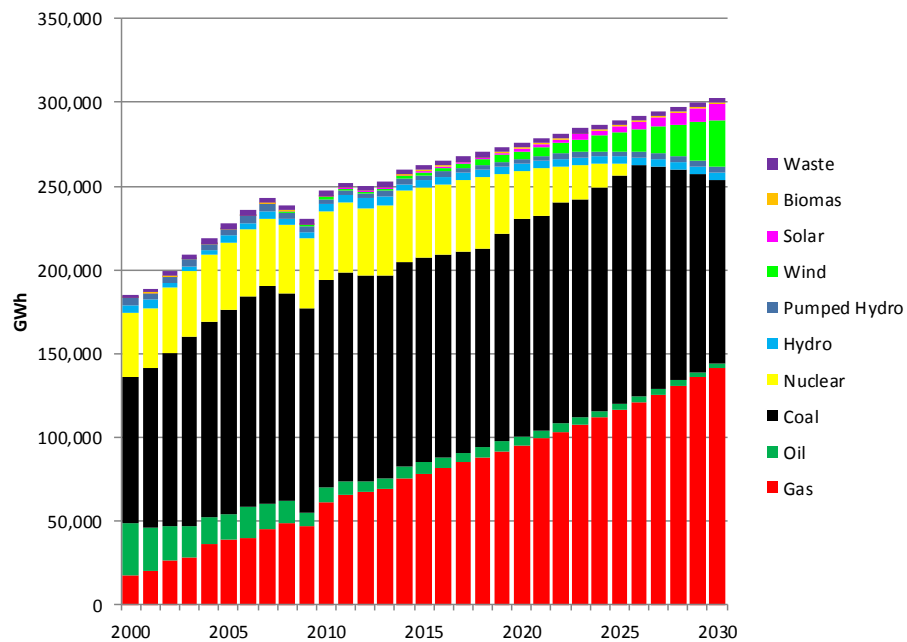
³⁶ Taiwan (2015)

³⁷ Liao, H. & Jhou, S. (2013)

³⁸ 'Political Discord Places Lungmen on hold', World Nuclear News, April 2014, <http://www.world-nuclear-news.org/NN-Political-discord-places-Lungmen-on-hold-2804144.html>



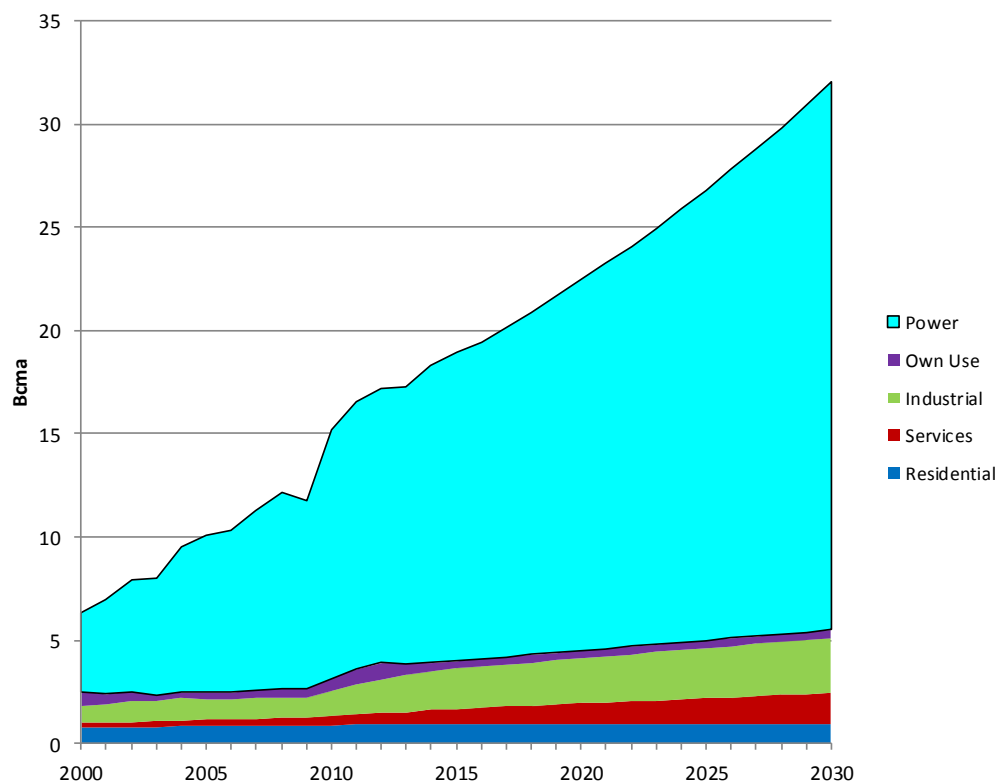
Figure 23: A Possible Future Generation Outlook to 2030 for Taiwan



Source: MOEA (2015), P. 87, Author's Assumptions and Analysis.

The resulting total gas demand outlook is shown in Figure 24, with gas demand by 2030 reaching 32.1 bcm compared to a 2015 figure of 19 bcm.

Figure 24: Taiwan Gas Demand Outlook to 2030



Source: MOEA (2015), Author's Assumptions and Analysis.

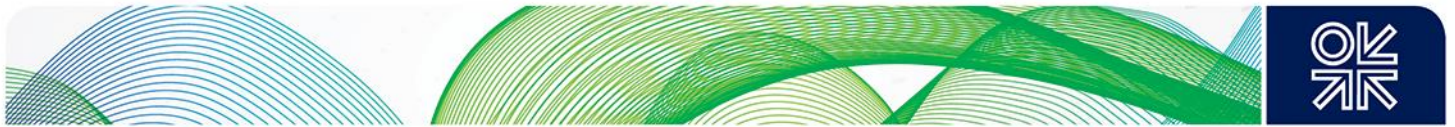
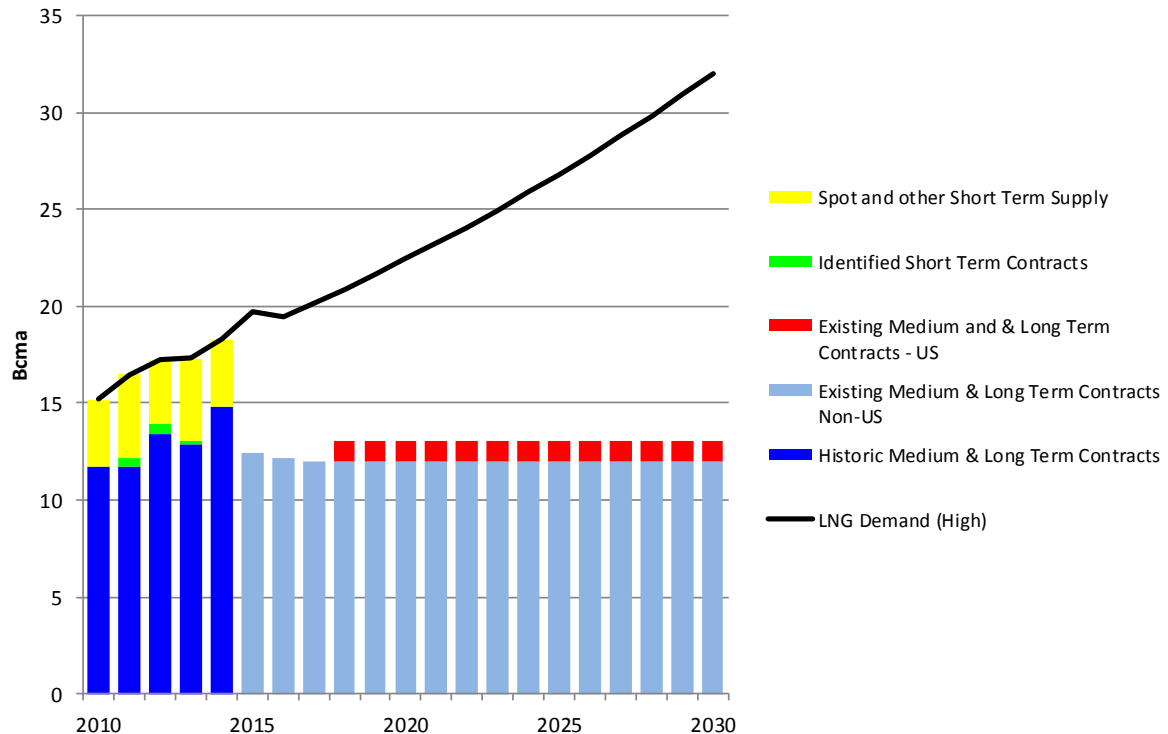


Figure 25: Taiwan Future LNG Demand and Contractual Position



Source: GIIGNL (2014), Author's Assumptions and Analysis

The combination of this LNG demand outlook with Taiwan's contractual position is shown in Figure 25. Taiwan has a stable long term contract portfolio of some 13.1 bcma, all but 1.1 bcma (US sourced LNG under a contract with GDF-Suez) being predominantly JCC price-linked. Taiwan, in the face of significant uncertainty over its future energy mix, (as opposed to its policy intentions), will need to consider entering into additional medium or long term LNG contracts towards the end of this decade if it wishes to avoid increasing dependence on the spot LNG market to fulfil its import requirements.

1.4.4 Taiwan - Conclusions

Taiwan has developed a successful high technology-focused export led economy which has in recent decades enjoyed high (if at times volatile) economic growth. It has based this on a high carbon intensity energy mix in which coal and oil are dominant. While gas represented only 13.8% of primary energy consumption in 2014 it has been growing at 5%/year on average since 2010. Taiwan's gas consumption is dominated by the power sector. Taiwan's quest to reduce its CO₂ emissions and energy import dependency are challenged by: a popular revolt against nuclear power; and, low regulated domestic prices for gas and electricity.

Even assuming high growth rates of future wind and solar investment (20%/year) the challenge for Taiwan is to contain coal consumption. It is feasible therefore that gas demand (and LNG imports) could continue to follow their 2010-2014 growth trend of 4 %/year. This would add an additional import requirement by 2030 of 14 bcm/y over 2014's level.

Table 3 shows the 'high case' discussed above and a Low case in which power demand growth for gas is only 1% /year.



Table 3: Taiwan LNG Import Outlook – Low and High Cases

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	15.2	16.6	17.2	17.3	18.3	19.7	19.2	19.5	19.7	20.0	20.3	20.5	20.8	21.0	21.3	21.6	21.8	22.1	22.4	22.6	22.9
	High Case	15.2	16.6	17.2	17.3	18.3	19.7	19.9	20.1	20.9	21.6	22.4	23.3	24.1	25.0	25.9	26.8	27.8	28.8	29.8	30.9	32.1
mtpa	Low Case	11.2	12.2	12.7	12.7	13.5	14.5	14.1	14.3	14.5	14.7	14.9	15.1	15.3	15.5	15.7	15.9	16.1	16.2	16.4	16.6	16.8
	High Case	11.2	12.2	12.7	12.7	13.5	14.5	14.3	14.8	15.4	15.9	16.5	17.1	17.7	18.4	19.0	19.7	20.4	21.2	21.9	22.7	23.6

1.5 Conclusions – Mature Asian LNG Markets

Japan, South Korea and Taiwan have accounted for around 60% of world LNG demand since 1980. Despite their differences the three countries face some common issues which will impact their future LNG demand:

- The future of nuclear power. Following the Fukushima disaster, Japan's future LNG requirements are expected to be most directly influenced by the pace and extent of the programme for restarting nuclear power plant. South Korea has restarted nuclear plant temporarily shut down due to safety considerations and government policy sees a continuing role for nuclear which might in future be contested. In Taiwan, government policy sees a phase-out of nuclear plant by 2025.
- Coal is the most price-competitive power generation fuel in all three countries. How the obvious clash between this and GHG obligations made at COP21 will be resolved remains to be seen. For now these countries are relying on (challenging) assumptions of energy efficiency and rapid renewable capacity growth to meet such targets.
- All three countries face the issue of low birth rates, aging populations and hence long term population decline. In terms of their economic model, this emphasises the need for export-orientated activity rather than domestic consumption to provide economic growth. Taiwan's diplomatic isolation and South Korea's inflexible labour market and the dominance of large conglomerates/incumbents are other long term challenges.
- Future economic growth is a key factor affecting power and industrial demand. Japan is an industrialised economy which has suffered low growth since the early 1990s. South Korea's previous strong economic growth has been muted since 2010 due to economic slowdown in the USA, Asia and the Eurozone. Whether these economies can maintain growth by stimulating domestic demand is an open question at present. Taiwan has also relied on export markets for its high tech products, however it remains to be seen whether its trade agreements signed in recent years, including with China, will extend its existing business model.
- Overall the LNG demand outlook for these three countries is somewhat less bullish than historic trends might suggest.



2. More Recent and Emerging Asian LNG Markets

2.1 Introduction

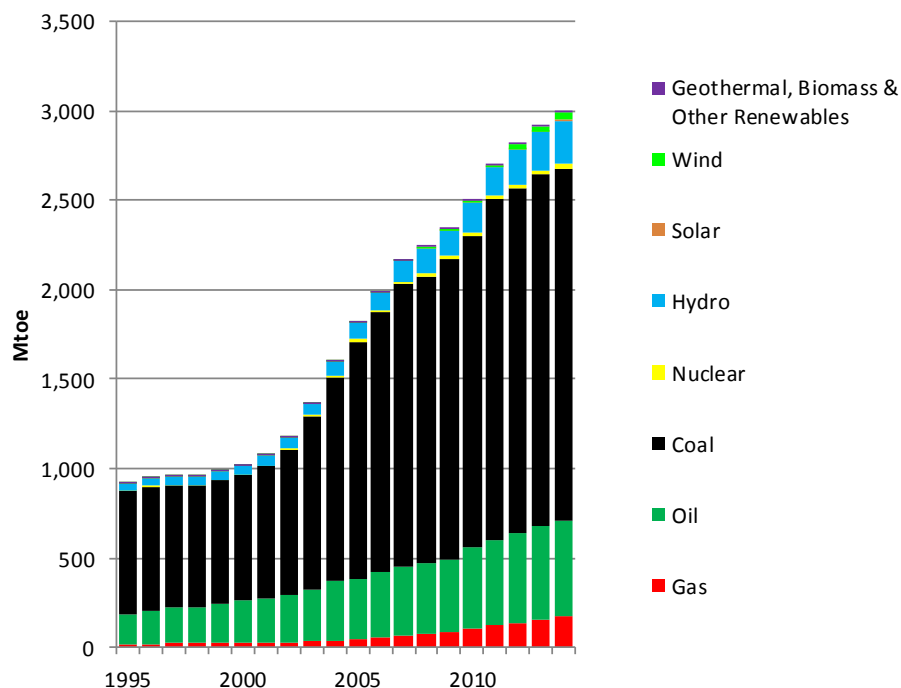
This section covers a range of markets: from China and India where LNG, as an already established channel of gas supply could grow to levels of major global importance; to more recently emerged and potential new importers where future LNG requirements are uncertain, such as: Singapore, Thailand, Indonesia, Malaysia, Pakistan, Bangladesh and Vietnam.

Each country has specific LNG import needs based on its gas demand expectations and domestic production and pipeline gas import outlook. This section reviews each in detail with common strands brought together in the concluding summary.

2.2 China

With a population of 1.37 billion³⁹ and the world's second largest economy in 2014, China has experienced exceptional economic growth since 1995: an annual average of 9.6%. In 2015 attention focussed on the slowdown in China's economic growth which officially was around 7% year on year in terms of GDP, but in terms of observed commodities imports and manufacturing output may have been lower. Figure 26 shows China's primary energy mix from 1995 to 2014, demonstrating that its economic growth, in energy terms, has been driven overwhelmingly by coal.

Figure 26: Primary Energy Mix of China 1995 to 2014



Source: BP (2015)

In 2014 the gas share of the energy mix stood at 5.6% compared with coal (65.7%), oil (17.9%) and hydro (8%). Despite its minor contribution, gas consumption grew at 13.2%/year on average from 2010 to 2014 (compared with total energy consumption growth of 4.7%). Energy consumption growth

³⁹ Countrymeters: Website of key country statistics: <http://countrymeters.info/en/China>

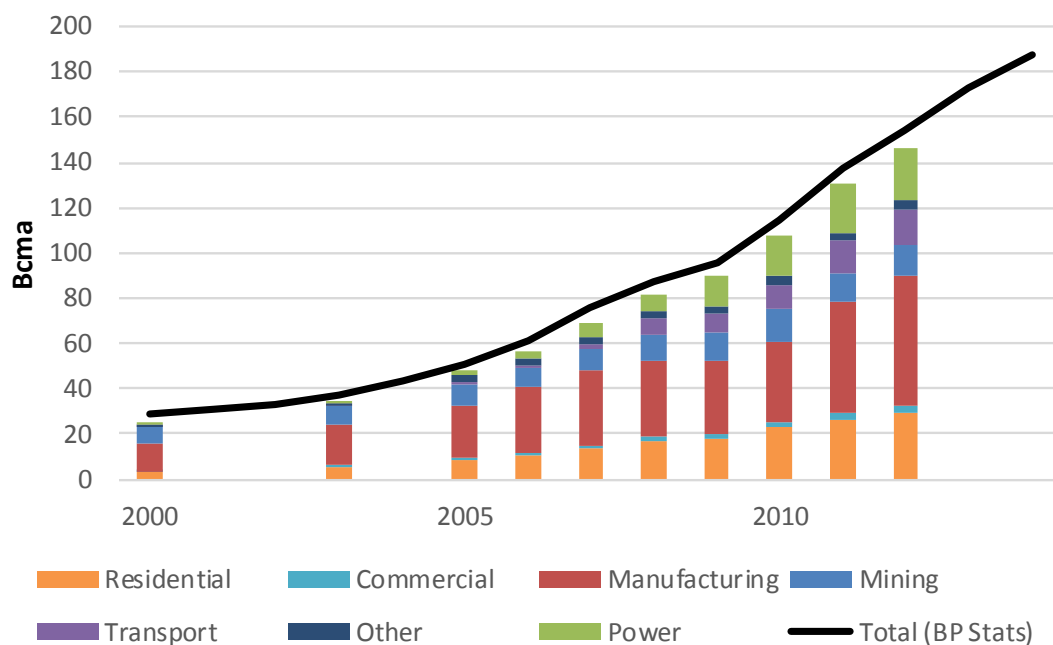


slowed in 2014 however to only a 2.5% increase over 2013 (gas 8.4%). Of particular note is that coal consumption in 2014 was virtually unchanged at the 2013 level⁴⁰.

2.2.1 Gas Consumption

Figure 27 shows the sectoral annual gas consumption (China (2014)) compared with the BP Statistical Review total figure. Residential and commercial demand has increased by 2 % on an annual average basis between 2005 and 2012; Manufacturing by 13.3% and power by 42.5%. Figure 28 shows a breakdown of manufacturing gas demand by industry segment. The main growth areas for gas demand are Chemicals, Fuel Processing, Metal and Metal Products and Machinery and Transport Products. Although these sectors saw a dip in demand during the post-crisis year of 2009, by 2011 strong growth has been subsequently re-established. In all these sectors however, gas plays 'second or third fiddle' to coal and oil.

Figure 27: China Gas Consumption by Sector 2000 - 2014

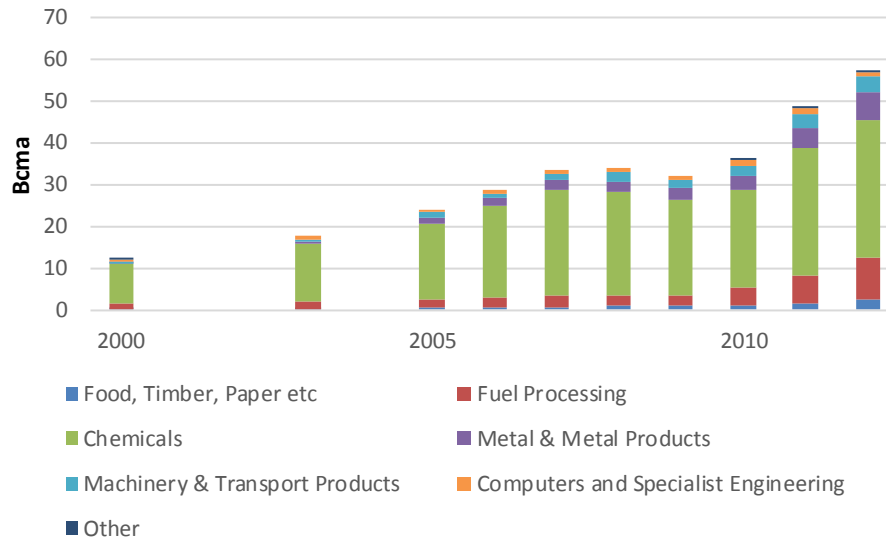


Sources: China (2014) (and previous editions), BP Statistical Review of World Energy.

⁴⁰ Note that other sources suggest that 2014 saw coal consumption decline by 2.9% from the 2013 level. 'Official data confirms Chinese coal use fell in 2014', Carbon Brief, 26th February 2015, <http://www.carbonbrief.org/official-data-confirms-chinese-coal-use-fell-in-2014>



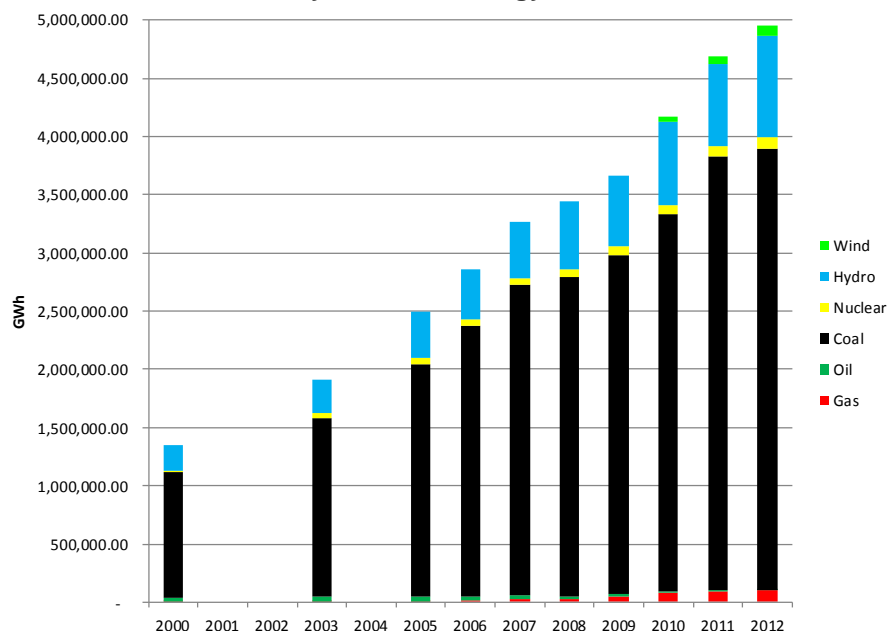
Figure 28: China Gas Consumption by Industry Segment 2000-2012



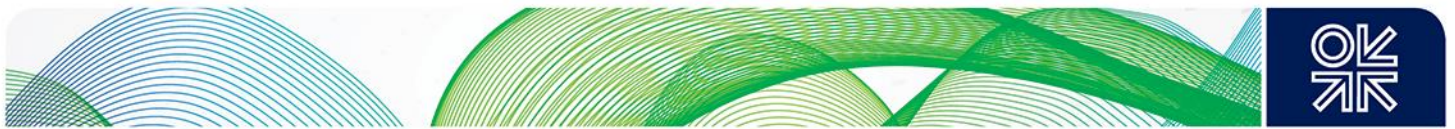
Source: China (2014) (and previous editions)

In the power sector gas continues to play a very minor role compared to coal and hydro (Figure 29). In 2012 gas provided only some 2% of power generation compared with coal (76%) and hydro (18%); this despite gas-fired generation growing by an estimated 24%/year on average between 2009 and 2012.

Figure 29: China Power Generation by Fuel/Technology 2000-2012



Source: China (2014) (and previous editions), Author's Calculations

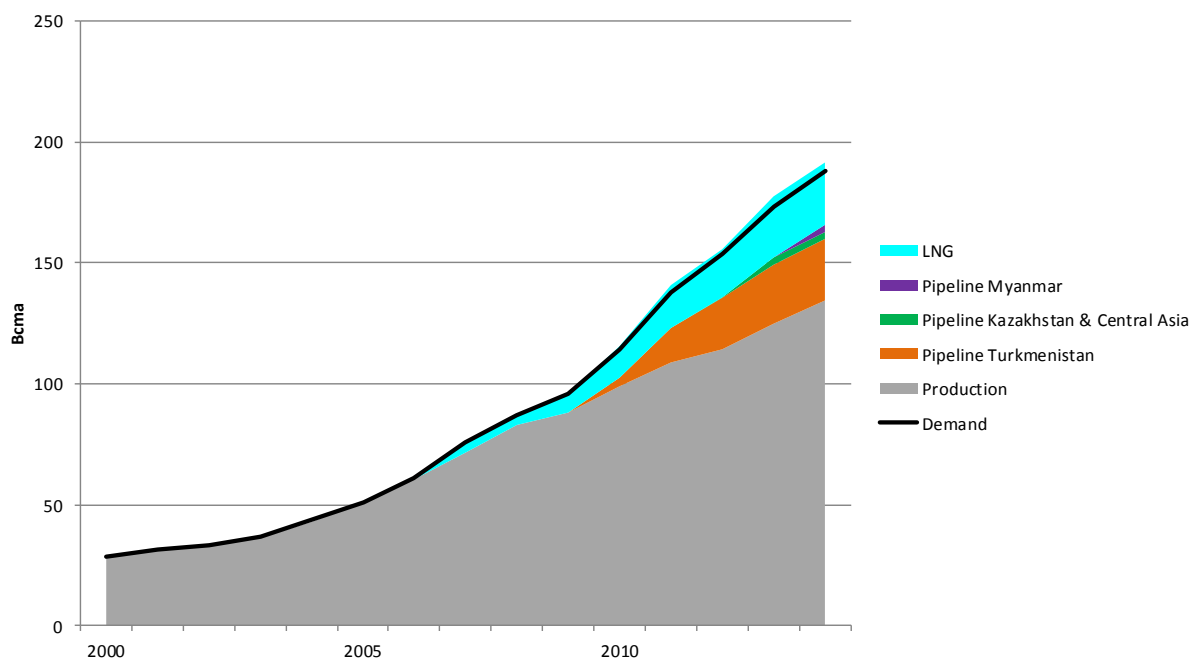


Monthly data for China's gas consumption is not available in a comprehensive form. While Kong, Dong and Zhou noticed limited seasonality on the basis of import patterns to end 2012⁴¹, the need for gas storage facilities in addition to the mid 2015 total of 7.3 bcm appears to be growing to deal with peak demand periods⁴².

2.2.2 Historical Chinese Natural Gas Supply and Demand

Figure 30 shows China's gas supply and demand balance for the period 2000 to 2014. From 2006 onwards demand outstripped growing domestic production with the balance initially supplied by LNG imports. Pipeline imports from Turkmenistan and Central Asia commenced in 2010 and from Myanmar in 2014. Domestic production is overwhelmingly from conventional sources with coal bed methane and shale gas contributing only 3.6 and 1.3 bcm in 2014 respectively⁴³. The revised (downward) target for shale gas in 2020 is 30 bcm/y⁴⁴. China has commenced a programme of producing natural gas from coal (synthetic natural gas). While this may alleviate the particulate pollution deriving from coal combustion in power generation and other uses, the process (without CCS) produces higher net CO₂ emissions and is a heavy consumer of water. The original intention was to produce 50 bcm/y of 'synthetic' natural gas by 2020, however it is likely that this will be scaled back to 15 bcm/y⁴⁵.

Figure 30: China Natural Gas Supply and Demand 2000-2014



Sources: BP (2015), GIIGNL

Note: Errors in 2010s due to different data sources.

The sources of China's LNG imports between 2006 and 2014 were initially dominated by Malaysia, Indonesia and Australian, but Qatar became the largest supplier from 2012.

⁴¹ Kong, Z, Dong X & Zhou, Z (2015)

⁴² China Natural Gas Map, <http://www.chinagasmap.com/theprojects/gasstorage.htm>

⁴³ 'China's unconventional output up', Platts International Gas Report, Issue 766, January 26, 2015.

⁴⁴ 'Yin and Yang of Chinese shale gas', Audrey Raj, Asian Oil & Gas, 27th May 2015, <http://www.aogdigital.com/component/k2/item/4912-yin-and-yang-of-chinese-shale-gas>

⁴⁵ 'In China, a tug of war over coal gas: Cleaner air but worse for the climate', Simon Denyer, Washington Post, 5th May 2015, https://www.washingtonpost.com/world/in-china-a-tug-of-war-over-coal-gas-cleaner-air-worse-for-the-climate/2015/04/27/b10992cc-e380-11e4-ae0f-f8c46aa8c3a4_story.html



In 2015 three of China's largest gas producers limited gas production in the face of demand slowdown but China still had to resell some long-term contracted LNG volumes.

2.2.3 Chinese Energy Policy

In June 2014, President Xi Jinping called for an energy policy shift based on five key areas: consumption, energy mix, technology, the energy system, and international co-operation. The government aims to cut annual coal consumption by 160 million tons by 2020. China intends to increase the share of gas in its energy mix to 10% in addition to achieving 100 GW of wind capacity by 2015 and further growth of solar PV from 21GW in 2015⁴⁶. China's energy policy gained greater international prominence through the joint announcement of national climate targets by President Barack Obama and President Xi Jinping in November 2014, ahead of the December 2015 Climate Summit. China intends that its CO₂ emissions will peak around 2030 and will use best efforts to bring that date forward⁴⁷.

From 2011 Chinese policy makers have undertaken a reform of Chinese natural gas pricing in the domestic market, progressively linking city gate prices to a formula including competing fuels, notably fuel oil and LPG, albeit with delayed re-calculation⁴⁸. This was an attempt to rationalise the internal pricing system in terms of gas price competitiveness with competing fuels; and to ensure an economic logic to the matrix of well head cost of supply, contractual price formulae and transport costs for Chinese supply sources (imports and domestic production). This has run into headwinds. Domestic prices under the Chinese competing fuel price formula have risen above those in international (LNG spot) markets leading to an oversupply in the domestic market. With oil and oil product prices low since the oil price slump of late 2014, gas faces challenges in achieving government energy mix targets in China unless prices are further liberalised. Wood Mackenzie estimate that China faces an oversupply of 18 bcm/y of contracted gas between 2015 and 2017 due to lower than expected demand growth.⁴⁹ It has been suggested that the government take advantage of the oversupply to push natural gas market reform and boost its share in transportation fuels⁵⁰.

2.2.4 Future Chinese Natural Gas Demand

In early 2014 the Chinese National Development and Reform Commission indicated that by 2020 it would raise its total natural gas supply capacity to between 400 bcm/y to 420 bcm/y⁵¹. As China's economy began to slow during 2014 CNPC in December 2015 provided a more modest demand outlook of 300 bcm/y by 2020 on a 'Business as Usual' Scenario⁵². The IEA in its 2015 World Energy Outlook showed a gas demand figure for China of 315 bcm/y for 2020 in the 'New Policies Scenario'⁵³. These demand outlooks to 2030 are shown in Figure 31. Due to a combination of high regulated gas prices and a slowdown in economic activity, China's gas consumption for 2015 appeared (in October) to be only 2.6% higher than 2014⁵⁴. This serves to cast doubt on some of the more aggressive demand trends in Figure 31. For the purpose of this analysis, Figure 31 includes a High Demand Case Assumption (dashed red line) which converges on the IEA New Policies case by 2020; and a Low Demand Case Assumption (dashed blue line) which by 2020 and beyond is the

⁴⁶ Ma, D (2015)

⁴⁷ 'China Energy Outlook 2015', Alexandra Cheung, Imperial College London, April 1st 2015, <http://www.imperial.ac.uk/blog/climate-at-imperial/2015/04/01/china-energy-outlook-2015/>

⁴⁸ For a comprehensive description see Chen, M (2014)

⁴⁹ 'High prices threaten Beijing's target of natural gas accounting for 10pc of energy use', Eric Ng, South China Morning Post, 21st June 2015, <http://www.scmp.com/business/china-business/article/1824591/high-prices-threaten-beijings-target-natural-gas-accounting>

⁵⁰ 'Reforms urged as natural gas glut falls on China', Want China Times, 11th August 2015,

<http://www.wantchinatimes.com/news-subclass-cnt.aspx?id=20150811000029&cid=1202> [I couldn't get through to this ref]

⁵¹ 'China to raise natural gas supply to 400-420 billion cubic metres by 2020: NDRC', The Economic Times, April 24th 2014, http://articles.economictimes.indiatimes.com/2014-04-24/news/49378338_1_ndrc-natural-gas-supply-national-bureau

⁵² CNPC (2015)

⁵³ IEA (2015a), P 196

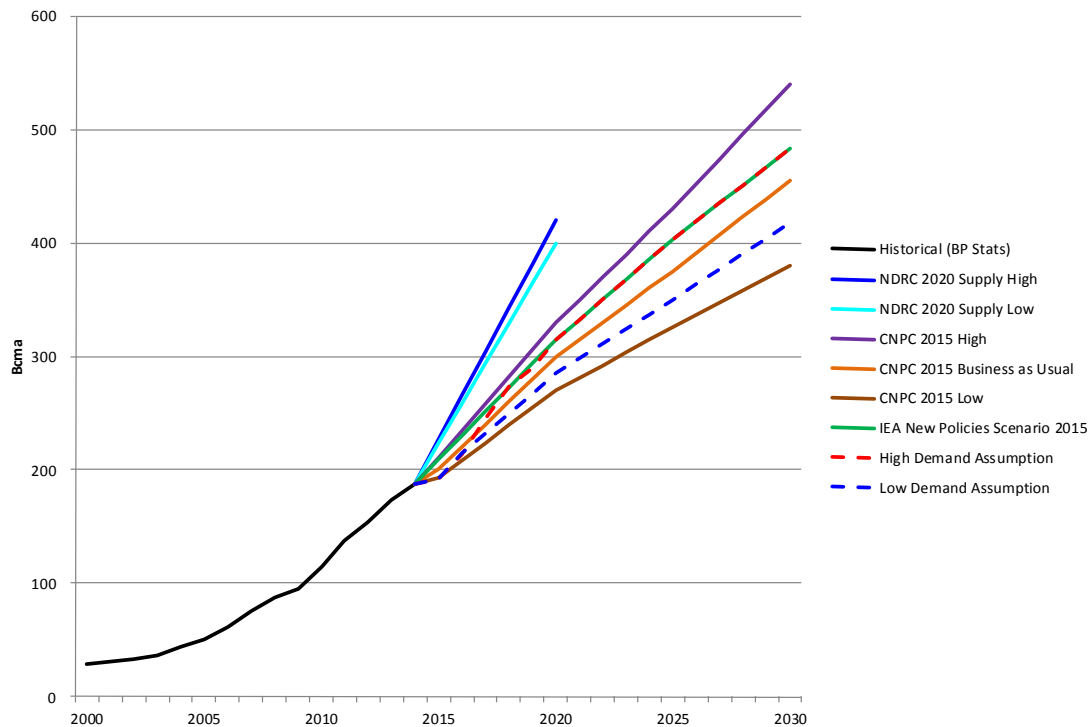
⁵⁴ 'China's weak natural gas demand cuts into LNG imports', ICIS, 7th October 2015,

<http://www.icis.com/resources/news/2015/10/07/9930658/china-s-weak-natural-gas-demand-cuts-into-lng-imports/>



average of the CNPC 2015 Business as Usual and Low cases. It is to be stressed that these two cases are illustrative and not based on quantitative analysis. CNPC (2015) however, presents a useful benchmark for the scope for potential coal to gas switching, driven by government policy with the aim of reducing CO₂ and particulate emissions: 40 bcm/y in power generation, 55 bcm/y in industry and 20 bcm/y in space heating. The proposed timescale for achieving this total 110 bcm/y of coal to gas substitution is 5 years⁵⁵.

Figure 31: China Historical and Future Natural Gas Demand from Various Sources



Sources: BP (2015), The Economic Times, April 24th 2014, http://articles.economictimes.indiatimes.com/2014-04-24/news/49378338_1_ndrc-natural-gas-supply-national-bureau, CNPC (2015), P 196.

2.2.5 China's Future Natural Gas Supply Mix

It is fair to say, in early 2016, that all elements of Chinese natural gas supply are prone to considerable future uncertainty. In the face of weak demand for natural gas in 2015 Chinese upstream companies were reported to be reducing conventional gas output while striving to meet targets for shale gas production⁵⁶.

Chinese domestic supply includes conventional gas, shale gas, coal bed methane and synthetic gas (gas from coal). There are few sources which provide a comprehensive outlook for each. The IEA in its 2015 World Energy Outlook (New Policies Scenario) provides a total Chinese domestic gas production total. CNPC⁵⁷ provide a useful breakdown based on analysis presented in November 2014. The outlook from both sources is shown in Figure 32.

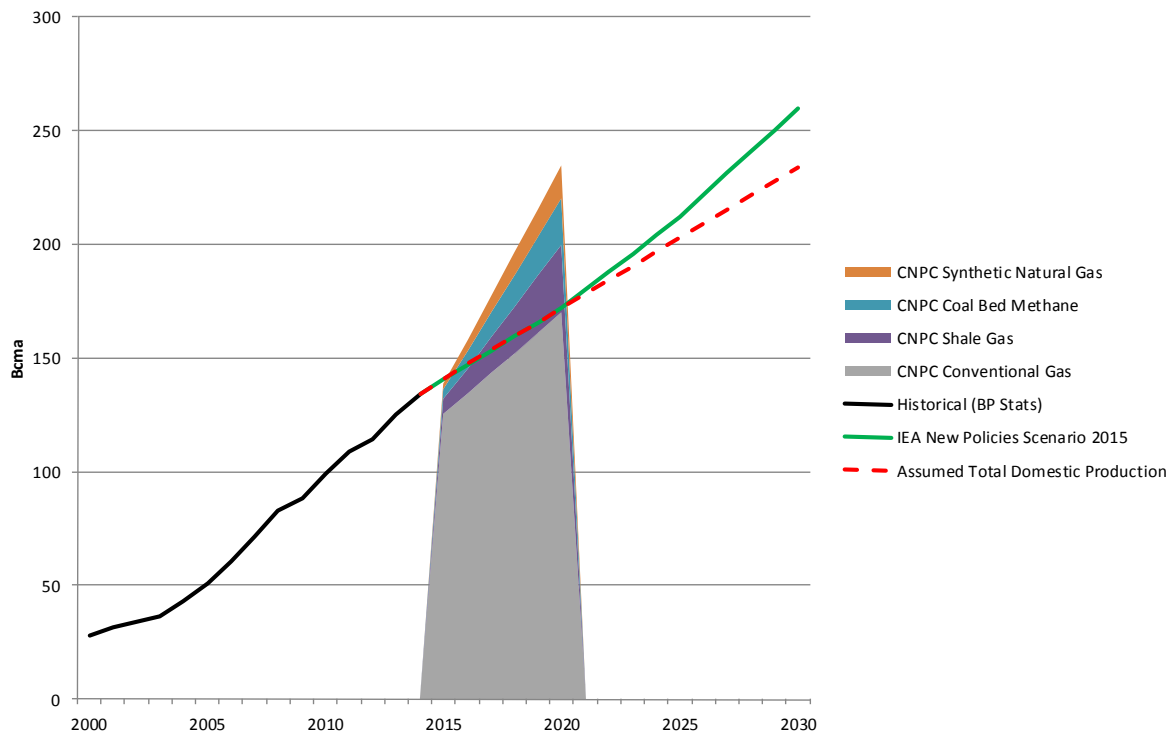
⁵⁵ 'CNPC (2015), Slide 19.

⁵⁶ 'China curbs conventional gas output, keeps shale target', Reuters, September 19th, 2015, <http://www.reuters.com/article/china-gas-idUSL3N10N44X20150910>

⁵⁷ CNPC (2014)



Figure 32: Historical and Future China Domestic Natural Gas Production



Sources: BP (2015), IEA (2015a), CNPC (2014).

Clearly CNPC sees greater potential for domestic production, with anticipated growth from shale gas, coal bed methane and synthetic natural gas (gas from coal) than is implied in the IEA New Policies Outlook. The analysis in the remainder of this section will be based on the assumption that Chinese domestic production follows the dashed red line in Figure 32, which tracks the IEA's 2015 New Policies Scenario assumption between 2015 and 2020 but continues on a linear trend (i.e. it diverges from the IEA case), which assumes an acceleration in domestic production in the 2020s. The author is inclined to take this conservative view given the lack of positive news on the progress of unconventional gas development in China.

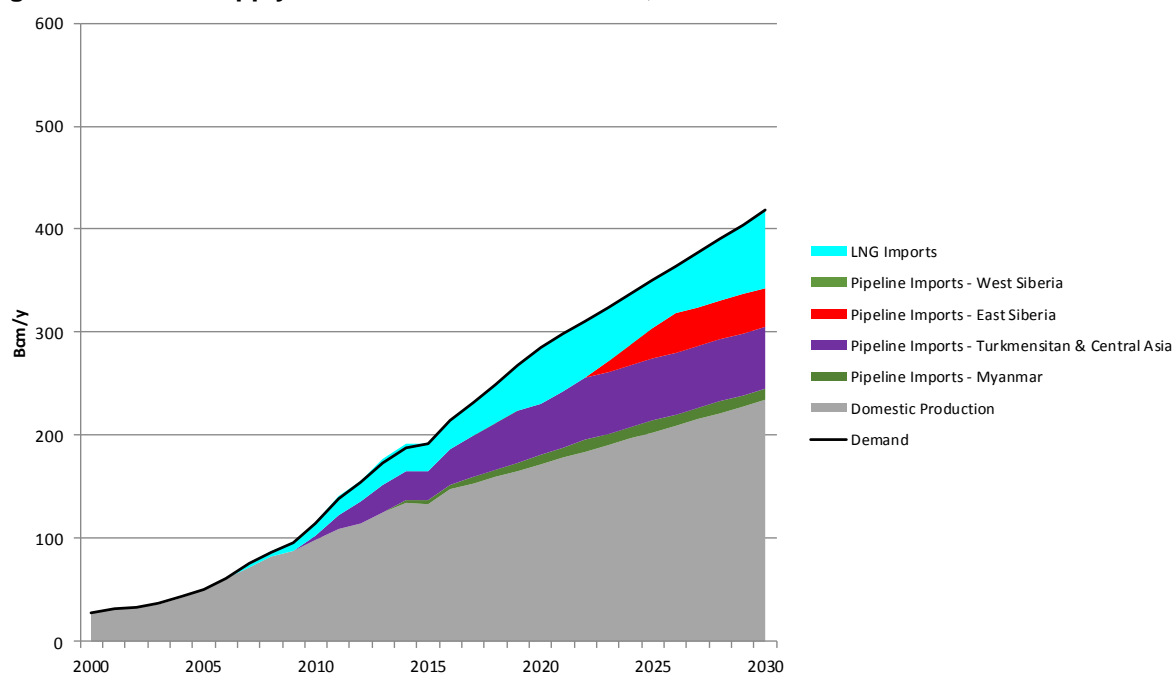
To varying degrees CNPC has invested both in upstream field development and pipeline infrastructure to bring Turkmenistan, Kazakhstan and Uzbekistan gas, entering at China's north-west border, to key demand centres. In 2014 total imports via this route amounted to 28.3 bcm, although existing and future pipeline capacity could raise this to 65 bcm/y. In 2014 China imported 3 bcm/y from Myanmar with the potential to raise this to 10 to 12 bcm/y in the future⁵⁸. China's two pending pipeline import deals with Russia were prominent in the media in 2014 and 2015; namely a 38 bcm/y contract to supply gas from East Siberian fields (the 'Power of Siberia' project) entering China at its north-east border; and a 30 bcm/y contract to supply West Siberian gas at China's north-west border, the 'Altai Pipeline'. These supplies were expected to come onstream around 2020. However, in mid-2015, media reports cast doubt on whether these arrangements would progress. The border price required by Gazprom in 2015 appeared high in comparison with contract and spot LNG import prices, and weakening Chinese demand growth has eased the pressure on China to fully consummate these two contracts.

⁵⁸ 'Natural Gas Imports into China – Prospects for Growth', King & Spalding Energy Newsletter, September 2014, <http://www.kslaw.com/library/newsletters/EnergyNewsletter/2014/September/article1.html>



Taking the 'Low Case' view of Chinese gas demand shown in Figure 31, a possible disposition of Chinese supply is shown in Figure 33, from conventional and unconventional sources and based on assumptions on future pipeline import levels.

Figure 33: China Supply and Demand – 2000 to 2030, Low Case



Source: BP (2015), IEA (2015a), GIIGNL (2014), Author's Assumptions

In Figure 33, Myanmar pipeline imports are assumed to grow by 1 bcm/year to reach 11 bcm/y by 2022, Turkmenistan and Central Asian imports grow from 2015 to reach 60 bcm/y by 2022 and the Russian East Siberian project is assumed to proceed with imports commencing in 2023 and growing to 38 bcm/y by 2026. LNG is assumed to make up the balance, reaching some 56 bcm/y in the early 2020s and 75 bcm/y by 2030. Table 4 summarises the balance at 5 yearly intervals.

Table 4: China Supply and Demand on Base Case Demand Assumptions bcm/y

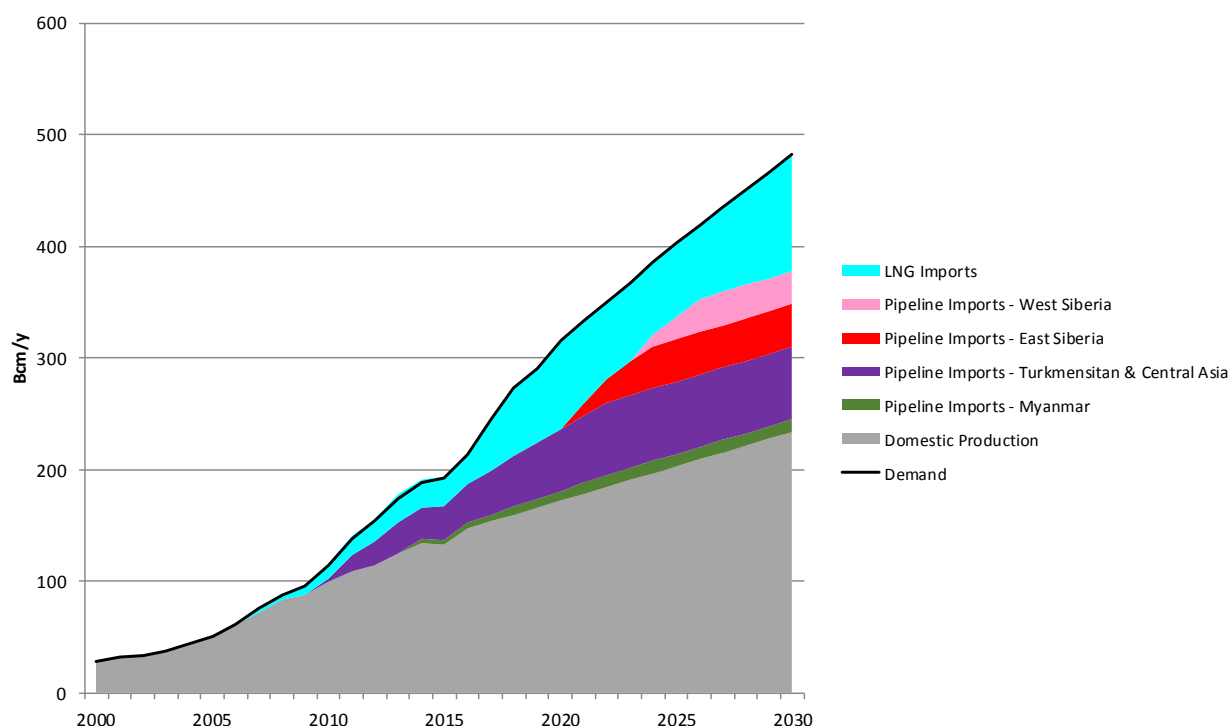
	2015	2020	2025	2030
Demand	192	285	350	418
Domestic Production	133	172	203	234
Pipeline Imports - Myanmar	4	9	11	11
Pipeline Imports - Turkmenistan & Central Asia	28	50	60	60
Pipeline Imports - East Siberia	0	0	30	38
Pipeline Imports - West Siberia	0	0	0	0
LNG Imports	27	54	46	75
Total Supply	192	285	350	418

Source: BP (2015), IEA (2015a), GIGNL (2014), Author's Assumptions

A high demand case could yield the balance shown in Figure 34. Here, Turkmenistan and Central Asian imports grow to 65 bcm/y by 2022. The Russian East Siberian project is assumed to commence in 2021 and grow to 38 bcm/y by 2024, and the West Siberian project (Altai line) is assumed to start in 2024 reaching 30 bcm/y by 2026. LNG is assumed to make up the balance reaching some 105 bcm/y by 2030. Table 5 summarises the balance at 5 yearly intervals



Figure 34: China Supply and Demand – 2000 to 2030, High Demand Assumption



Source: BP (2015), IEA (2015a), GIGNL (2014), Author's Assumptions

Table 5: China Supply and Demand on High Case Demand Assumptions bcm/y

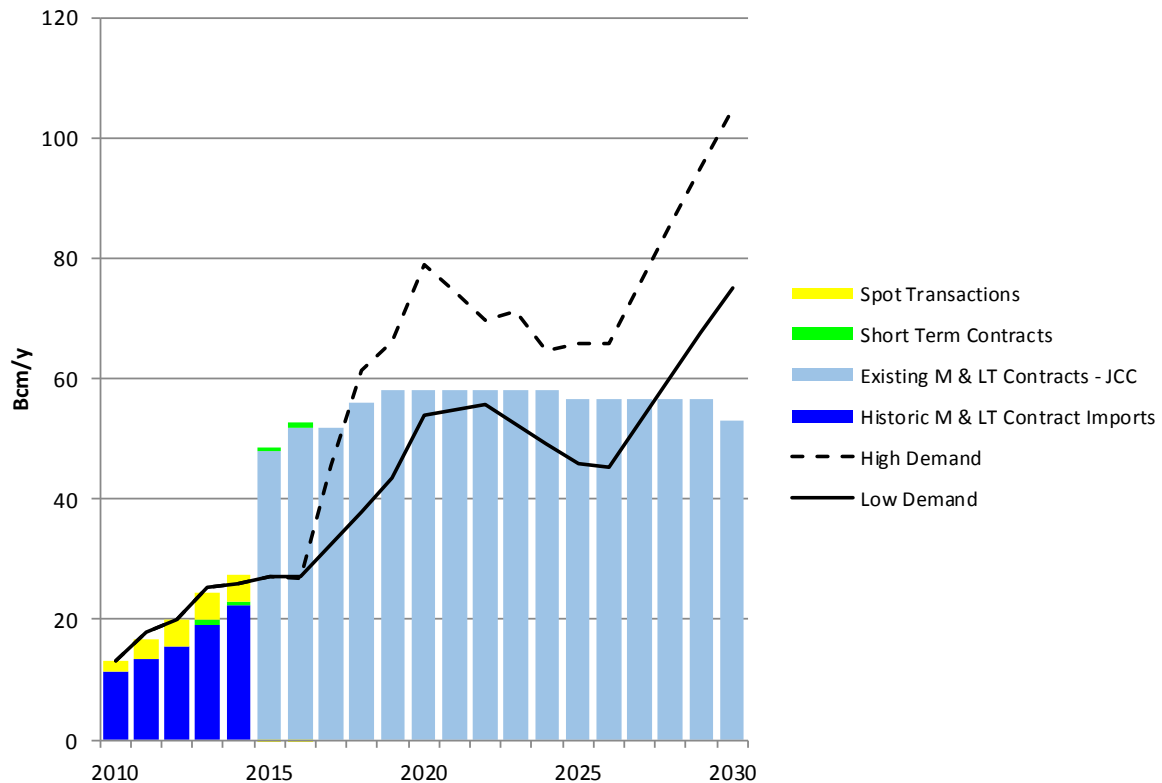
	2015	2020	2025	2030
Demand	192	315	403	483
Domestic Production	133	172	203	234
Pipeline Imports - Myanmar	4	9	11	11
Pipeline Imports - Turkmenistan & Central Asia	28	55	65	65
Pipeline Imports - East Siberia	0	0	38	38
Pipeline Imports - West Siberia	0	0	20	30
LNG Imports	27	79	66	105
Total Supply	192	315	403	483

Source: BP (2015), IEA (2015a), GIGNL (2014), Author's Assumptions

Figure 35 shows the future LNG import requirements on these two demand cases and compares them with China's current portfolio of future long term contracts. Historic data on China's LNG imports; long term and short term contract deliveries and spot/short term transactions is also shown. Note Platts data shows 2015 Chinese LNG imports amounted to 26 bcm/y, little changed on 2015 levels.



Figure 35: China's LNG Import Requirements on Base and High Future Demand Cases and Contractual Commitments



Sources: GIIGNL (2014), Author's Calculations

In 2015 and 2016, China had more contracted LNG than it could absorb. In the Low demand case defined above, China would continue to be over-contracted to varying degrees until the mid-2020s. Postponement of the second Russian pipeline project and/or reducing take-up of Turkmenistan/Central Asian volumes would mitigate this position. Failing this, China would be required to sell-on contracted LNG volumes (as it did in 2015) potentially incurring a loss relative to contract price.

2.2.6 China Conclusions

Over the past 10 years or so, China has been the source of increasing demand for a range of imported commodities including oil and natural gas. China's situation has changed however as, from 2014, it appeared to enter a phase of lower growth, re-focussing away from energy intensive state-directed infrastructure and manufacturing activity towards domestic consumption and services. Any move to a lower carbon-intensive economy on the part of China needs to address its overwhelming reliance on coal. Growth in nuclear, hydro, wind and solar PV will help in this regard, but the timescales required to achieve targets through such investment programmes are often underestimated. Gas has an obvious role to play, however China is rightly concerned to ensure: that it maximises its domestic production capabilities; prices for contracted imported supplies are acceptable and such arrangements do not hinder the move to market-related pricing in the future. The challenge for China is to manage all of the above in the context of uncertain future energy requirement and fuel mix.

Table 6 summarises China's LNG import requirements for the cases discussed above.



Table 6: China LNG Import Cases

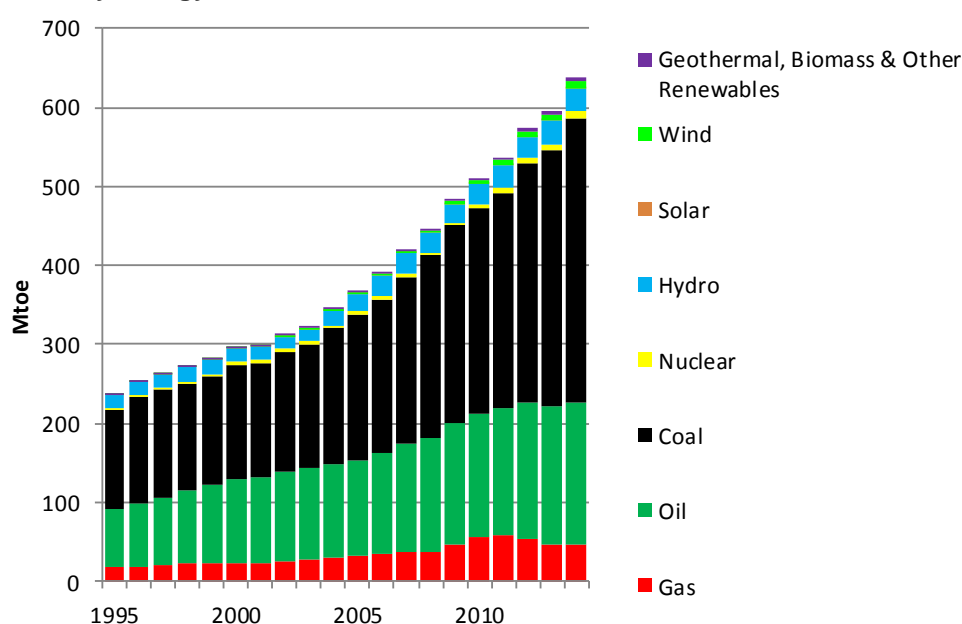
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	13.1	17.8	19.9	25.3	25.8	27.2	27.0	32.5	38.0	43.5	54.0	54.8	55.6	52.4	49.2	46.0	45.4	52.8	60.2	67.6	75.0
	High Case	13.1	17.8	19.9	25.3	25.8	27.2	26.8	45.6	61.4	66.2	79.0	74.4	69.8	71.2	64.6	66.0	65.8	75.6	85.4	95.2	105.0
mtpa	Low Case	9.6	13.1	14.7	18.6	19.0	20.0	19.9	23.9	27.9	32.0	39.7	40.3	40.9	38.5	36.2	33.8	33.4	38.8	44.3	49.7	55.1
	High Case	9.6	13.1	14.7	18.6	19.0	20.0	19.7	33.5	45.1	48.7	58.1	54.7	51.3	52.4	47.5	48.5	48.4	55.6	62.8	70.0	77.2

2.3 India

2.3.1 Energy Mix and Gas Supply and Demand

With a population of 1.2 billion India's GDP growth has exceeded the world average in every year since 2001. India's economy, in 2014, in terms of GDP comprises Agriculture (18%), Industry (31%) and Services (51%)⁵⁹, thus being more highly dependent on agriculture than other major Asian LNG importers. After low economic growth in 2013, the incoming Prime Minister Narendra Modi has promised to implement economic reform to attract private-sector investment. India's economy continues to operate far below its potential with corruption, poor infrastructure, and fiscal deficits all major obstacles to economic growth.⁶⁰

Figure 36: Primary Energy Mix of India 1995 to 2014



Source: BP Statistical Review of World Energy

India's Primary energy consumption trends are shown in Figure 36. The energy mix is dominated by coal (56.5% in 2014) and oil (28.3% in 2014) with gas a poor third at 7.1%. The decline in gas use since 2011 is a consequence of a reduction in domestic production (see later). Total energy consumption has grown by 5.8%/year on average between 2010 and 2014, while coal consumption in the same period grew by 8.5%/year. Comprehensive sectoral consumption for LNG imports is not

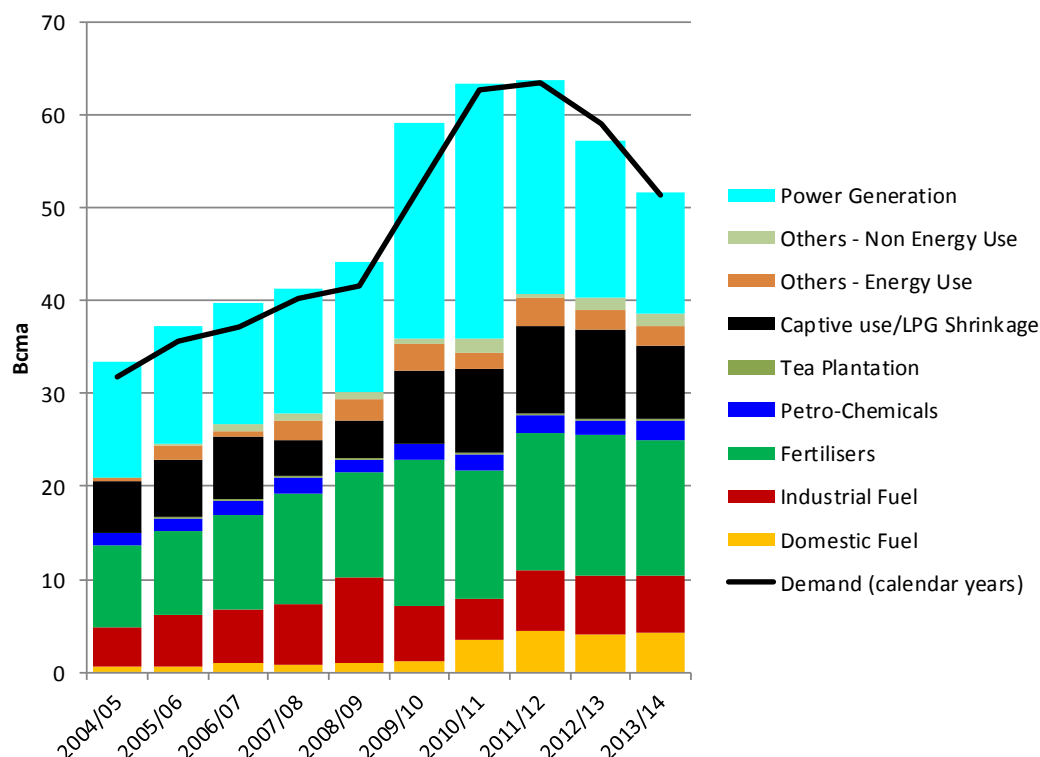
⁵⁹ 'Sector-wise contribution of GDP of India', Statistics Times, 8th July 2015, <http://statisticstimes.com/economy/sectorwise-gdp-contribution-of-india.php>

⁶⁰ India, 2015 Index of Economic Freedom, The Heritage Foundation, <http://www.heritage.org/index/country/india>



forthcoming. Figure 37 provides an estimated breakdown of natural gas including LNG consumption and compares this with total annual demand (calendar years).

Figure 37: Estimated India Natural Gas Consumption by Sector 2004/05 to 2013/14



Sources: BP (2015), India (2013a), P. 28, Corbeau, A. (2010), P. 38, India (2013b), P.14

Note: Detailed consumption breakdown by sector is only reported annually (fiscal years) for domestic gas production. LNG consumption by sector was prorated based on data for 2012/13 only. Total demand was from the BP Statistical Review (calendar years).

The key dynamic in this figure is the decline in overall demand post 2011; the result of abruptly falling domestic production which was not compensated for by an increase in LNG imports. Figure 37 shows a fairly stable level of industrial consumption, a higher consumption in domestic fuel post 2009/10 but with limited growth thereafter, a generally growing consumption in fertiliser production to 2009/10 (again stagnant in recent years) and a power sector demand which grew rapidly to 2010/11 but which has reduced after this peak.

For a description of the Indian domestic gas market, the reader is directed to Sen, A (2015)⁶¹. The following summarises key points from this paper.

Gas consumption in India is governed by the 'Gas Utilisation Policy' which supports the rationing of domestically produced gas to Tier 1 'priority sectors' with the resulting balance released for sale to the wider Indian market. The major 'priority sector' customers are City Gas for households and transportation, fertilizers, LPG extraction plants and grid-connected power plants. Industrial users including steel, refineries and petrochemical plant, commercial users and merchant power plants are regarded as Tier 2, or lower priority users in this allocation system.

⁶¹ Sen, A (2015)



Prices received by producers of domestic gas are determined by state regulation and vary depending on the original licencing terms. The majority of domestic gas prior to the price reform implemented in April 2015, received \$4.20/MMBtu. While observers expected the price reform to result in a near doubling of this price, in the event by selecting a basket dominated by relatively low international reference prices (US Henry Hub, Canadian hub prices, and Russian domestic price as prime examples), the post reform price rose modestly to \$4.66/MMBtu.

LNG is imported at prices determined by contractual terms (historically an oil price linkage) or spot prices. Some LNG may be directed to Tier 1 consumers (with the state or state-owned entities funding any subsidies involved). Tier 2 consumers will pay the import price of LNG consumed, plus any additional transportation and other costs.

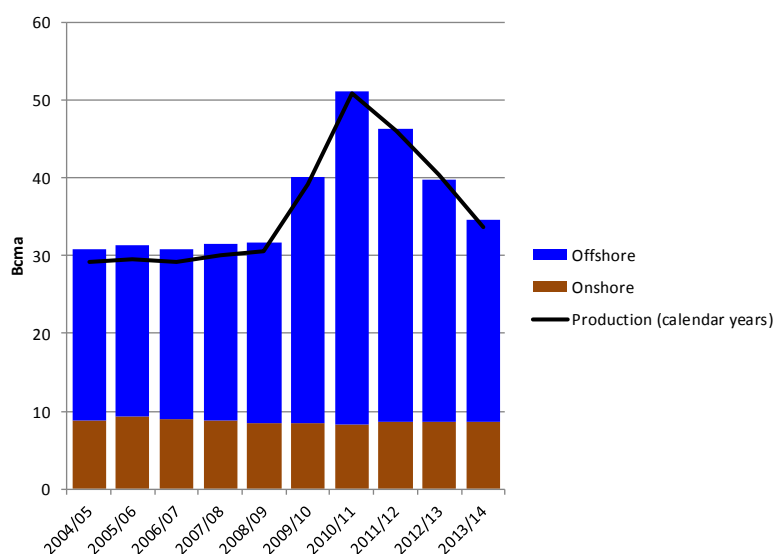
India consumes some 30 million tonnes/year of fertiliser, second only to China. Of the urea manufactured in India 81% derives from gas feedstock. Farmers receive a subsidy amounting to 50% of the cost of urea. While a growing population and economic wealth will support increased underlying demand for fertilizer, the ability of farmers to pay the 'real' price of urea (or the government's ability to fund the current subsidy arrangement) may act to dampen its availability.

In the power sector gas-fired generation accounts for just under 10% of total installed capacity. Power demand is limited by the geographical extent and capacity of distribution grids. Gas fired power suffers due to its higher cost relative to domestic or imported coal.

City gas consumption shows continued growth potential both in terms of domestic and commercial consumption and in transportation. Again actual demand growth may be suppressed by infrastructure constraints and by supply availability. This sector is generally able to pay prices based on LNG imports. The outlook for industrial demand is less clear.

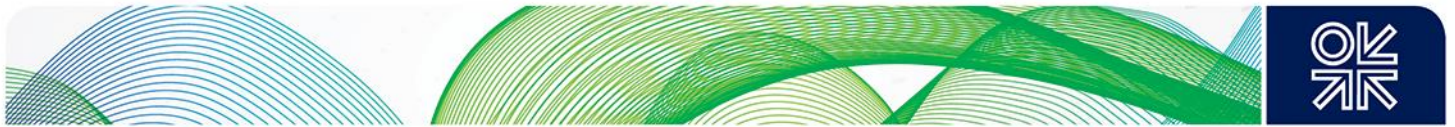
Figure 38 shows Indian natural gas production from 2004/05 to 2013/14. Onshore production has been stable at around 8.5 bcm/y during this period. Offshore production rose dramatically in 2008/09 and 2009/10 with the development of the 'KG-D6' eastern offshore gas field. Production from this field has declined, apparently due to poor well performance and higher than anticipated water influx from the reservoir⁶².

Figure 38: India Domestic Gas Production 2004/05 to 2013/14



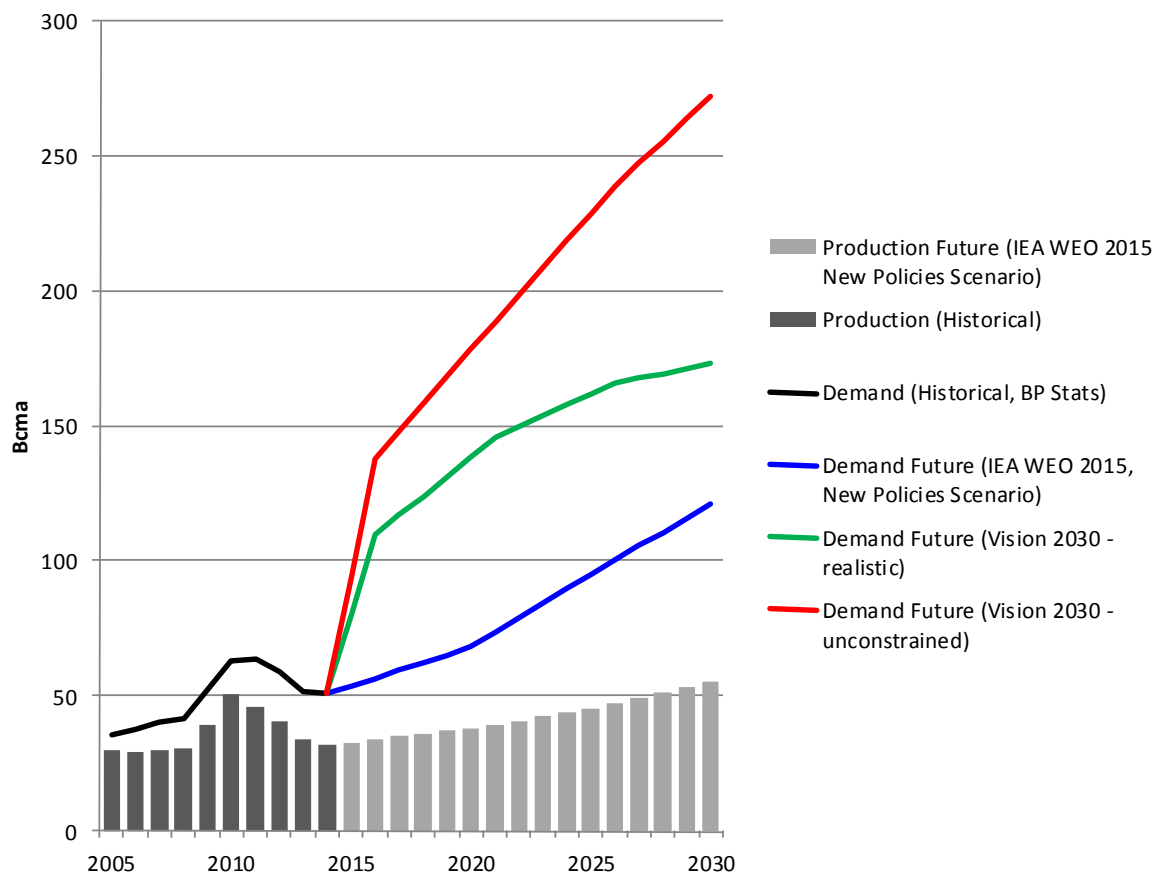
Sources: BP (2015), India (2015)

⁶² 'RIL, BP offer \$5 billion to hike KG D6 gas output', 1st May 2013, Oil and Gas Journal, <http://www.ogj.com/articles/print/volume-111/issue-4/exploration---development/ril-bp-offer-5-billion-to-hike.html>



In Sen, A. (2015), the outlook for increased domestic production is not an optimistic one. Significant additional resource potential could be accessed by exploration and development, but only at wholesale or 'beach' prices above \$8/MMBtu. As policymakers seem unwilling or unable to either set the regulated price at a level which would incentivise further domestic supply development, or allow wholesale price to be determined by the forces of supply and demand, any future growth in Indian gas demand will need to be met by LNG imports. The IEA in its World Energy Outlook 2015 New Policies Scenario anticipates Indian production reaching 55 bcm/y by 2030, presumably assuming a change in pricing policy prior to the 2020s (Figure 39). On the demand side, Figure 39 shows two rather optimistic outlooks (Vision 2030 cases) which were derived with the intention of making a case for policy reform to stimulate the domestic gas industry. The IEA 2015 New Policies Scenario case, by contrast, shows a more measured growth to 2020 followed by an acceleration to reach 121 bcm/y by 2030. The IEA Current Policies Scenario by 2030 is little changed from the New Policies case (4% lower); the '450 Scenario' however has modestly higher gas demand growth in the 2020's (achieving 134 bcm/y by 2030).

Figure 39: India Demand Outlooks and Domestic Gas Production 2005 to 2030



Sources: IEA (2015a), India (2013b), BP (2015).

India began LNG Imports in 2004. To end 2014, Qatar has supplied 80% of India's LNG with Nigeria and, prior to 2014, Egypt as the main secondary suppliers. In December 2015, India's Petronet negotiated a 50% reduction in price under a contract signed in 1999 and was not required to pay for volumes not imported in 2015 under the Take or Pay clause. While India's potential future market size



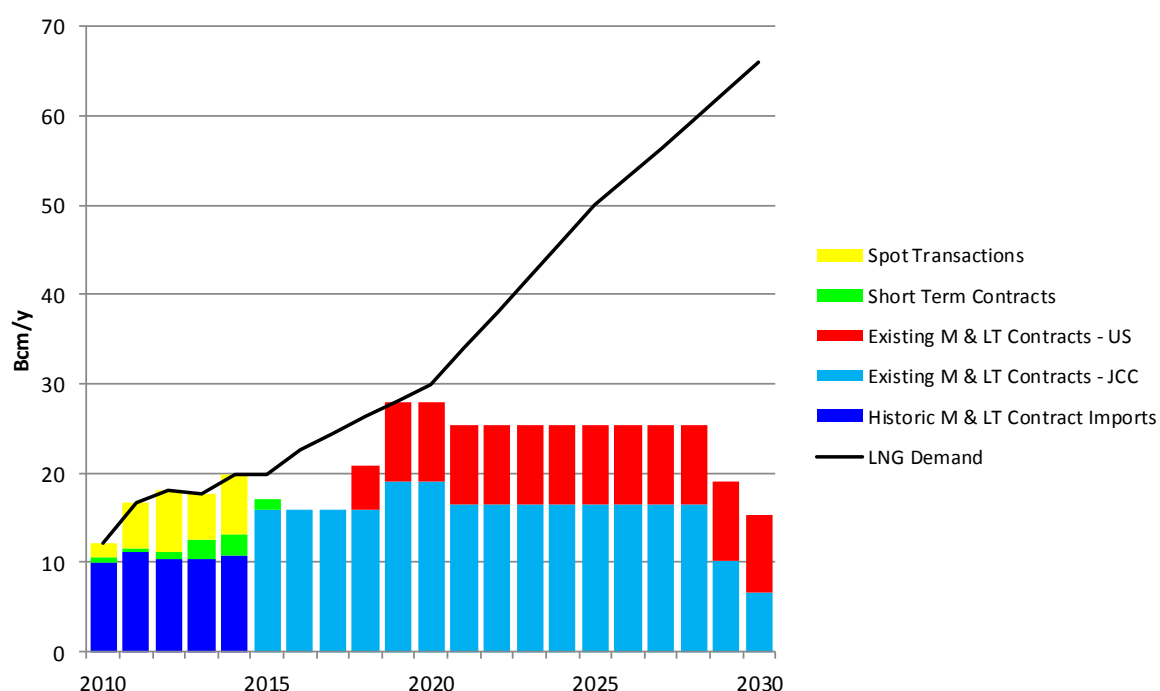
was certainly an issue to consider, the wisdom of signing the initial deal on what is alleged to have been a fixed price of \$12 to \$13/MMBtu is certainly questionable⁶³.

2.3.2 India's Energy Policy and Future Gas Demand Outlook

India's energy policy continues to appear somewhat unfocussed, notably the expedient handling of the issue of gas price reform and the 'wishful thinking' support of solar and wind versus the realistically achievable scale of such capacity build. There appears to be an acceptance that coal will provide for the main growth for power generation and no specific policy for natural gas. Future gas growth will be hindered by a number of factors. On the supply side domestic production will not materially increase until wholesale/beach prices are either liberalised or at the least linked to a credible international index. Additional supply will be in the form of LNG imports, with the low probability of completing pipeline import projects due to demand uncertainties, linking infrastructure build requirements and pricing issues. The process of gas allocation in the domestic market and attendant subsidies is a further barrier to establishing a market price based on supply demand, especially with no obvious plan to extend pipeline infrastructure.

Estimating future demand trends for natural gas in India is therefore problematic at this juncture. In the absence of any rational alternative scenario, the LNG import requirement derived from the IEA WEO 2015 New Policies Scenario is used as a 'default base case', albeit that its assumptions regarding future domestic production growth appear optimistic.

Figure 40: India Future LNG Import Requirements and Contractual Commitments



Source: IEA (2015a), GIIGNL (2014), Author's Analysis

Figure 40 overlays the IEA WEO 2015 LNG import requirement on India's past LNG imports and future contractual positions. With continued purchase of spot and short term LNG and its commitment to purchase US LNG export volumes, India's LNG import needs are covered on this outlook until the early 2020s.

⁶³ 'Petronet strikes deal with Qatar's RasGas to get LNG at half-price', The Hindu Business Line, 31st December 2015, <http://www.thehindubusinessline.com/news/qatar-agrees-to-lower-price-in-gas-deal-with-india/article8049876.ece>



Table 7 shows India's tentative LNG import requirements. The outlook described above is labelled the 'low' case and a notional future additional growth of 20% constitutes the 'high' case. In the context of the uncertainty surrounding India's future energy mix, this upside could occur in response to rising air quality problems due to the reliance on coal and domestically burned biomass, or alternatively as a consequence of domestic production growth failing to emerge.

Table 7: India LNG Import Requirements

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	12.2	16.8	18.1	17.8	19.8	19.9	22.6	24.5	26.3	28.2	30.0	34.0	38.0	42.0	46.0	50.0	53.2	56.4	59.6	62.8	66.0
	High Case	12.2	16.8	18.1	17.8	19.8	19.9	27.2	29.4	31.6	33.8	36.0	40.8	45.6	50.4	55.2	60.0	63.8	67.7	71.5	75.4	79.2
mtpa	Low Case	9.0	12.3	13.3	13.1	14.5	14.6	16.6	18.0	19.3	20.7	22.1	25.0	27.9	30.9	33.8	36.8	39.1	41.5	43.8	46.2	48.5
	High Case	9.0	12.3	13.3	13.1	14.5	14.6	20.0	21.6	23.2	24.8	26.5	30.0	33.5	37.1	40.6	44.1	46.9	49.8	52.6	55.4	58.2

India has four existing LNG terminals with an aggregate capacity of 20.7 mtpa⁶⁴ (28.2 bcm/y). While prospective terminals are planned, the need to secure demand centres and access infrastructure for future projects will likely constrain both low and high cases from the mid to late 2010s unless these projects proceed in a timely manner.

2.4 Singapore

Singapore has developed a successful free-market economy relying heavily on exports, in consumer electronics, information technology products, pharmaceuticals, and a growing financial services sector. It has experienced comparatively high rates of GDP growth; in the period 2004 to 2007 these were in the range 7.5% to 9.5%/year⁶⁵. Singapore's energy mix comprises oil products (87% in 2014), Natural Gas 12.8% and renewables 0.2%. The average annual increase in primary energy consumption between 2010 and 2014 was 2.4 %⁶⁶.

2.4.1 Gas Consumption and Supply

In 2014 Singapore consumed 10.7bcm⁶⁷ of natural gas, overwhelmingly in the power generation sector (Figure 41), with industry a distant second. The rapid growth in gas demand for power has been mainly driven by displacing oil products; in 2010 gas accounted for 80.6% of the generation fuel mix, by 2014 it was 95.4%⁶⁸. Annual electricity demand growth in Singapore has been 2.1% on average between 2010 and 2013⁶⁹.

⁶⁴ GIIGNL (2014), P. 29.

⁶⁵ World Bank (2015)

⁶⁶ BP (2015)

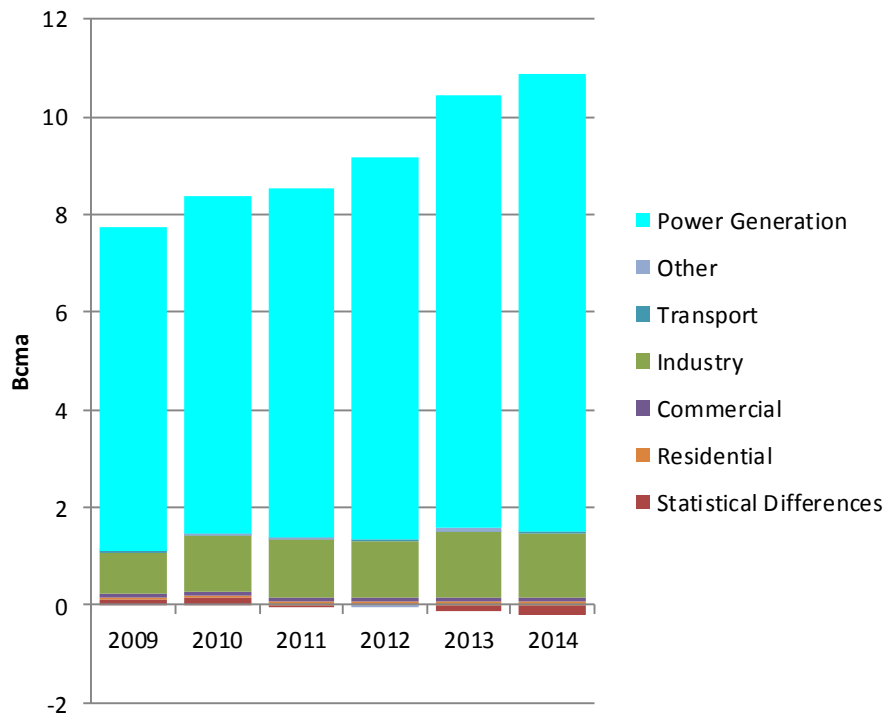
⁶⁷ The comparable figure in the BP Statistical Review of World Energy, 2015 is 10.8 bcm/y.

⁶⁸ EMA (2015a)

⁶⁹ EMA (2015b)



Figure 41: Singapore Gas Consumption 2009 - 2014



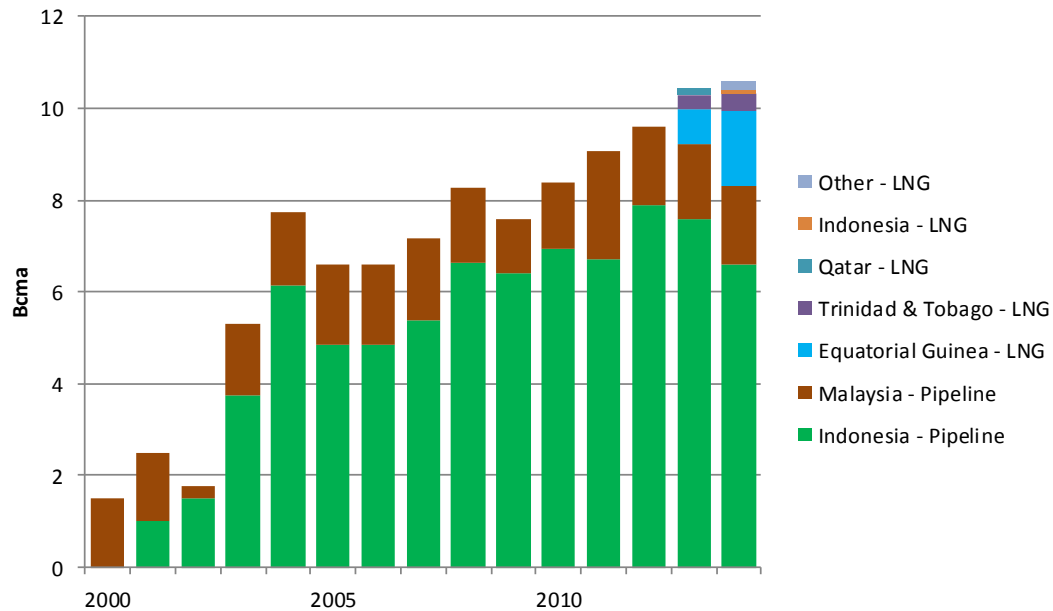
Source: EMA (2015b)

Having no domestic production, Singapore imports gas by pipeline from Malaysia (from 1992) and Indonesia (from 2001) and, since 2013, LNG from a number of suppliers (Figure 42). Indonesian pipeline volumes were reduced in favour of LNG in 2014 and Singapore has a policy of discouraging new pipeline supply as it pursues its goal of becoming a regional LNG trading centre. The Indonesian pipeline contracts are expected to end between 2015 and 2025⁷⁰. It is assumed that the Malaysian pipeline contracts also end in 2025.

⁷⁰ 'Singapore LNG Policy won't affect RI exports: BPMigas', The Jakarta Post, March 6th 2012, <http://www.thejakartapost.com/news/2012/03/06/singapore-lng-policy-won-t-affect-ri-exports-bpmigas.html> [I couldn't get to this ref]



Figure 42: Singapore Sources of Gas Supply 2000 - 2014

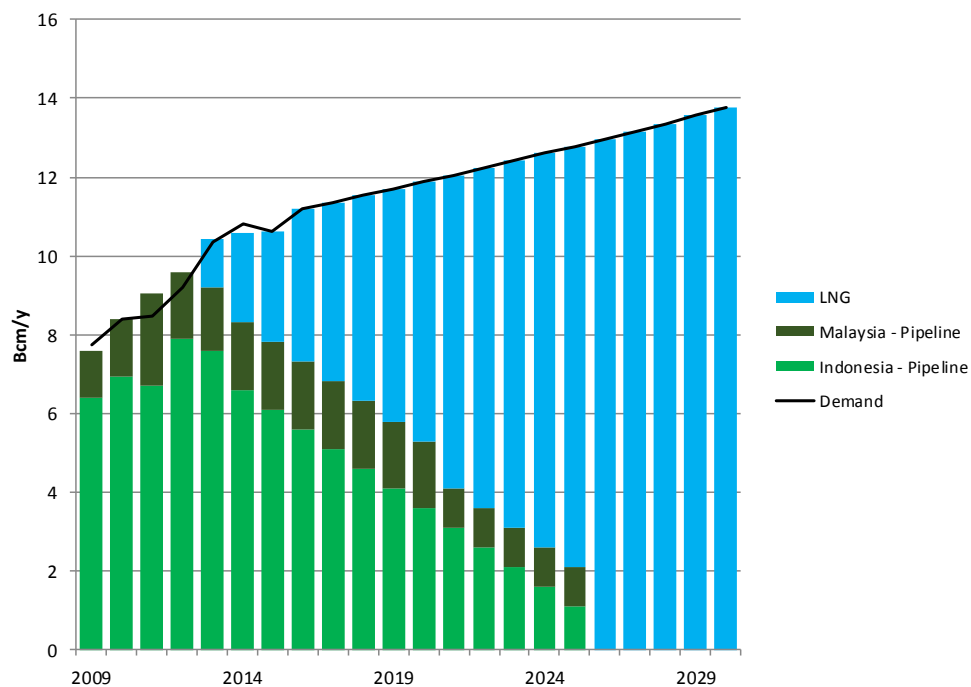


Sources: BP (2015), GIIGNL (2014)

2.4.2 Singapore Outlook

The outlook for Singapore LNG requirements is shown in Figure 43. On the demand side a future 2% annual growth in gas consumption in the power and industrial sectors is assumed and 1% in other sectors. With the fall off in pipeline imports discussed above, this results in an LNG requirement in 2020 and 2025 of 6.6 and 10.7 bcm/y respectively.

Figure 43: Outlook for Singapore Gas Demand and Supply



Source: BP (2015), EMA (2015b), GIIGNL (2014), Author's Assumptions



Singapore has an LNG contract with BG for 3.8 bcm/y, in force from 2013 to 2033⁷¹. In addition to existing arrangements, the Singapore Energy Market Authority is pursuing a second tender to attract LNG importers whose role would be to act as importers and re-sellers to both Singapore domestic buyers but also to LNG bunker fuel consumers and buyers from other importing markets⁷².

Table 8 shows the outlook for LNG imports (low case) based on Figure 43. A high case was constructed based on gas in power and industry growing by 2%/year and 1% in other sectors.

Table 8: Singapore LNG Import Outlook

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case				1.2	2.3	2.8	3.9	4.6	5.2	5.9	6.6	8.0	8.6	9.3	10.0	10.7	13.0	13.2	13.4	13.6	13.8
	High Case				1.2	2.3	2.8	4.0	4.7	5.5	6.2	6.9	8.4	9.1	9.9	10.6	11.4	13.8	14.0	14.3	14.6	14.9
mtpa	Low Case				0.9	1.7	2.1	2.9	3.4	3.8	4.3	4.8	5.8	6.3	6.8	7.4	7.9	9.5	9.7	9.8	10.0	10.1
	High Case				0.9	1.7	2.1	2.9	3.5	4.0	4.6	5.1	6.2	6.7	7.3	7.8	8.4	10.1	10.3	10.5	10.7	10.9

2.5 Thailand

Since 2000 Thailand's annual GDP growth has averaged 3.9%⁷³, although somewhat volatile. Notwithstanding political uncertainty since the 1970s, Thailand has moved from a low to an upper-income country in less than a generation. The global economic recession cut exports, and in late 2011 Thailand's recovery was interrupted by severe flooding in the industrial areas of Bangkok and surrounding provinces. In 2013, agriculture comprised 12.1% of GDP with industry 43.6% and services 44.2%.⁷⁴ A military coup in May 2014 has come under criticism by the international business community for micro-management and lacking an economic strategy⁷⁵. No timetable is in place at the time of writing for the election of a new government and the prospect of economic stagnation must be considered in the absence of positive political and economic management developments.

⁷¹ GIIGNL (2014), P. 10

⁷² 'Appointment of New Liquefied Natural Gas Importers for Singapore', 29th May 2015, EMA, <https://www.ema.gov.sg/cmsmedia/Gas/Post-3%20Mtpa%20RFP%20Document%20Stage%20Two%2029May2015.pdf>

⁷³ World Bank (2015)

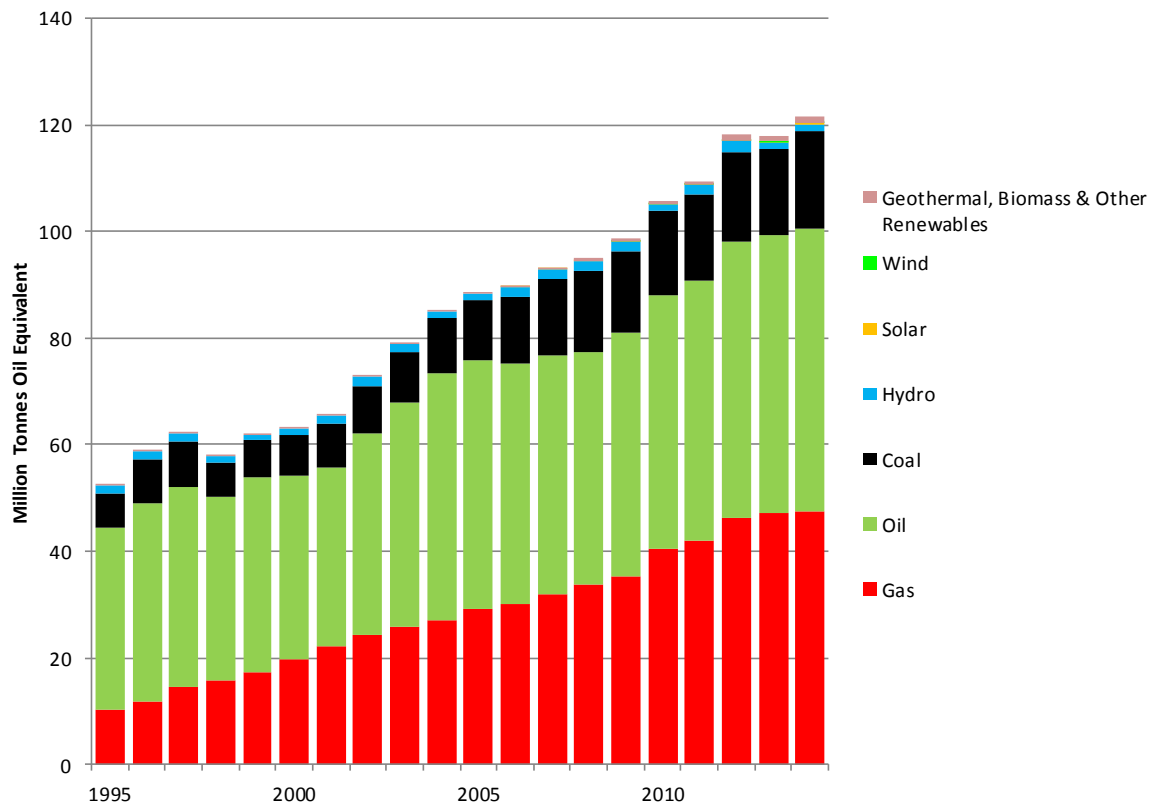
⁷⁴ CIA (2015b)

⁷⁵ 'Thailand's Generals Don't Have an Economic Plan', Bloomberg View, August 4th 2015.

<http://www.bloombergvew.com/articles/2015-08-04/thailand-s-generals-don-t-have-an-economic-plan>



Figure 44: Thailand Primary Energy Mix 1995 - 2014



Source: BP (2015)

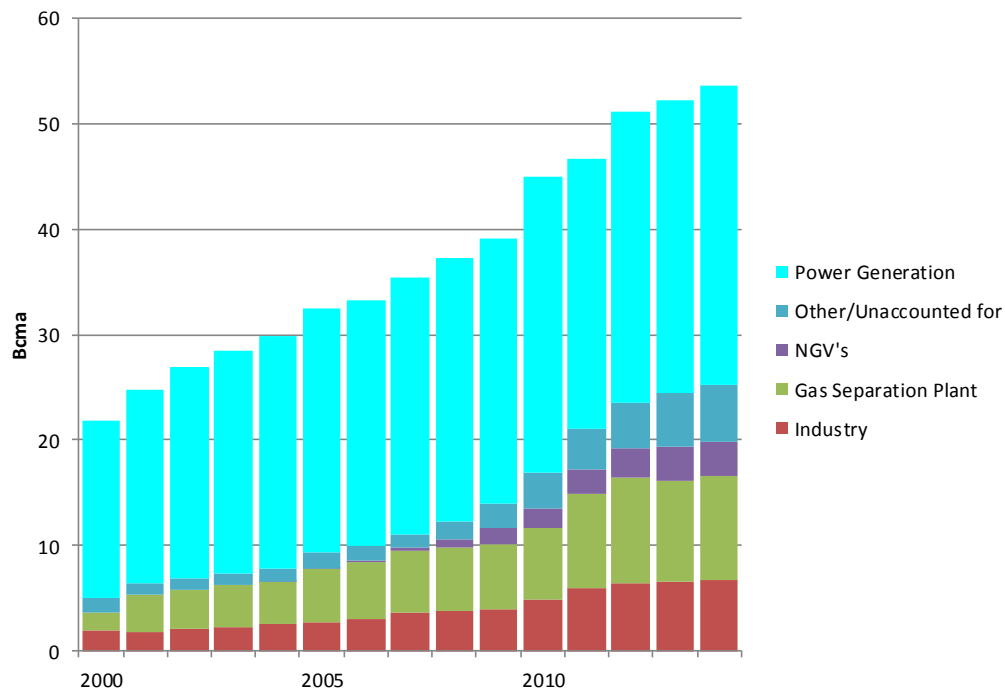
As shown in Figure 44, the gas share of Thailand's energy mix is substantial (39% in 2014), second only to oil.

2.5.1 Gas Consumption and Supply

Thai gas consumption has steadily increased from 2000 (Figure 45). Although the power sector dominates (where gas consumption has been stagnant for 2012-2014), industry and use as fuel in its large gas separation plant (producing ethane, propane and other NGLs from domestic wet gas production) are also significant.



Figure 45: Thailand Natural Gas Consumption 2000 - 2014



Source: EPPO (2015)

Note: 'Other/Unaccounted for' is a balancing item.

On supply, Thailand's domestic production appears to have reached a plateau (Figure 46). Thailand imports gas from fields located offshore in the Myanmar sector of the Gulf of Thailand. Established infrastructure configurations could serve to safeguard this gas for Thailand, despite a need for more gas in Myanmar.

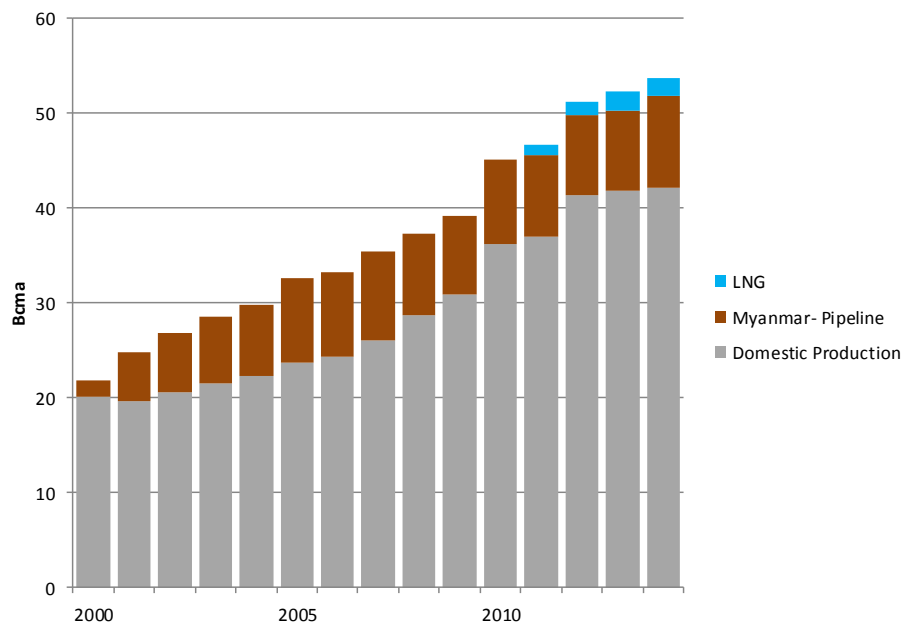
Thailand commenced LNG imports in 2011 through its Map Ta Phut regas terminal (capacity 7.3 bcm/y)⁷⁶. If the IEA's expectation of rapid future declines in Thailand's domestic production are borne out⁷⁷, Thailand will need to expedite plans for further LNG import capacity to maintain, let alone grow gas demand.

⁷⁶ GIIGNL (2014), P. 30

⁷⁷ IEA (2015b), P. 42



Figure 46: Thailand Gas Supply 2000 - 2014



Sources: EPPO (2015), GIIGNL (2014)

In its 2015 Power Development Plan⁷⁸, Thailand assumes a growth in power demand of 3.9%/year. Through expanding the role of renewables and hydro, it seeks to limit the growth in gas and coal-fired generation. The plan also assumes nuclear power commencing in 2028.

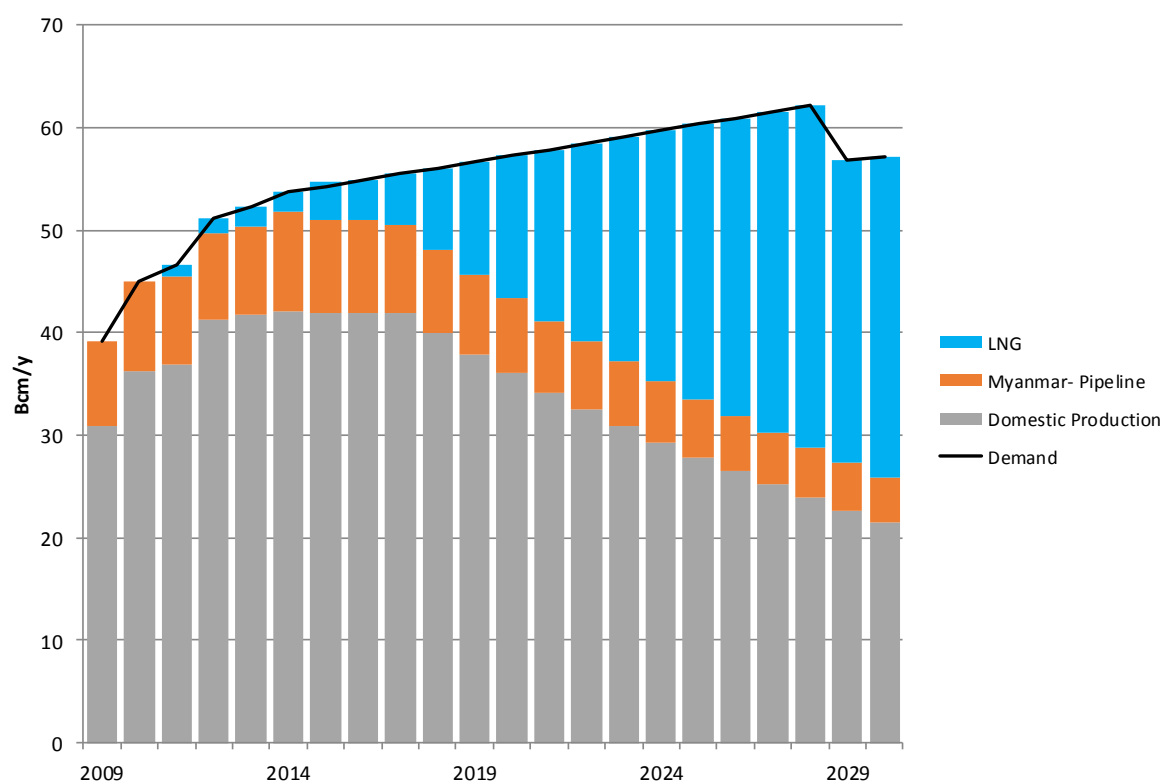
2.5.2 Thailand Outlook

The Power Development Plan forms the basis of a reasoned, if somewhat speculative outlook for Thailand's future LNG requirements. On the demand side, power sector consumption is based on the plan referred to above. Industry growth is assumed at 1.5%/year. Together with a 1%/year growth in NGVs and 'other/unaccountable' this would take Thailand's gas consumption from 53.7 bcm in 2014 to 57.1 bcm in 2030. If we assume that Thailand's domestic production, and the offshore Myanmar fields exporting gas to Thailand begin their production decline in 2017 at 5%/year, Figure 47 paints a picture of a growing and substantial market for LNG. LNG imports, on these assumptions, would in 2020 and 2025 be 11.0 and 20.4 bcm/y respectively.

⁷⁸ Thailand (2015)



Figure 47: Thailand Gas Supply and Demand Outlook 2009 - 2030



Sources: EPPO (2015), GIIGNL(2014), Author's assumptions.

Note: Reduction in demand in 2029 and 2030 is due to the government's assumed start of nuclear power.

Table 9 shows the outlook for LNG imports (high case) based on Figure 47. A low case was constructed based on an assumption that domestic production in future declines at 2.5%/year (rather than 5%), as a consequence of further exploration success and field development.

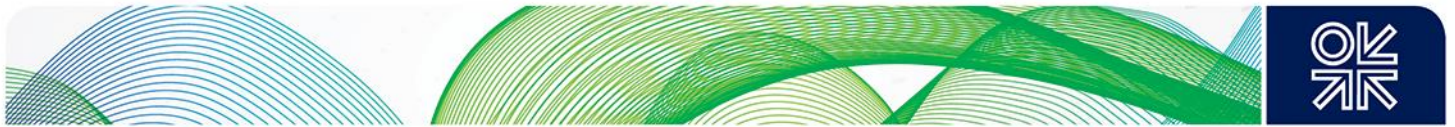
Table 9: Thailand LNG Import Outlook

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	0.0	1.1	1.4	2.0	1.9	3.7	3.9	4.9	7.0	9.0	11.0	13.0	14.9	16.7	18.6	20.4	22.1	23.8	25.5	21.3	22.5
	High Case	0.0	1.1	1.4	2.0	1.9	3.7	3.9	4.9	8.0	11.0	13.9	16.7	19.4	21.9	24.4	26.8	29.1	31.3	33.4	29.6	31.2
mtpa	Low Case	0.0	0.8	1.0	1.5	1.4	2.7	2.8	3.6	5.1	6.6	8.1	9.5	10.9	12.3	13.6	15.0	16.3	17.5	18.8	15.6	16.5
	High Case	0.0	0.8	1.0	1.5	1.4	2.7	2.8	3.6	5.9	8.1	10.2	12.3	14.2	16.1	17.9	19.7	21.4	23.0	24.6	21.7	22.9

2.6 Indonesia

Comprising an archipelago of which the major islands are Sumatra, Java, Sulawesi, the southern part of Borneo and the western section of New Guinea (Irian Jaya), Indonesia is a populous country (256 million) whose GDP (2014 data) comprises agriculture (14.2%), industry (45.5%) and services (40.3%). Energy intensive industries include oil & gas, mining, chemicals, textiles, products derived from processing agricultural inputs and tourism.⁷⁹ Indonesia has enjoyed consistently high GDP

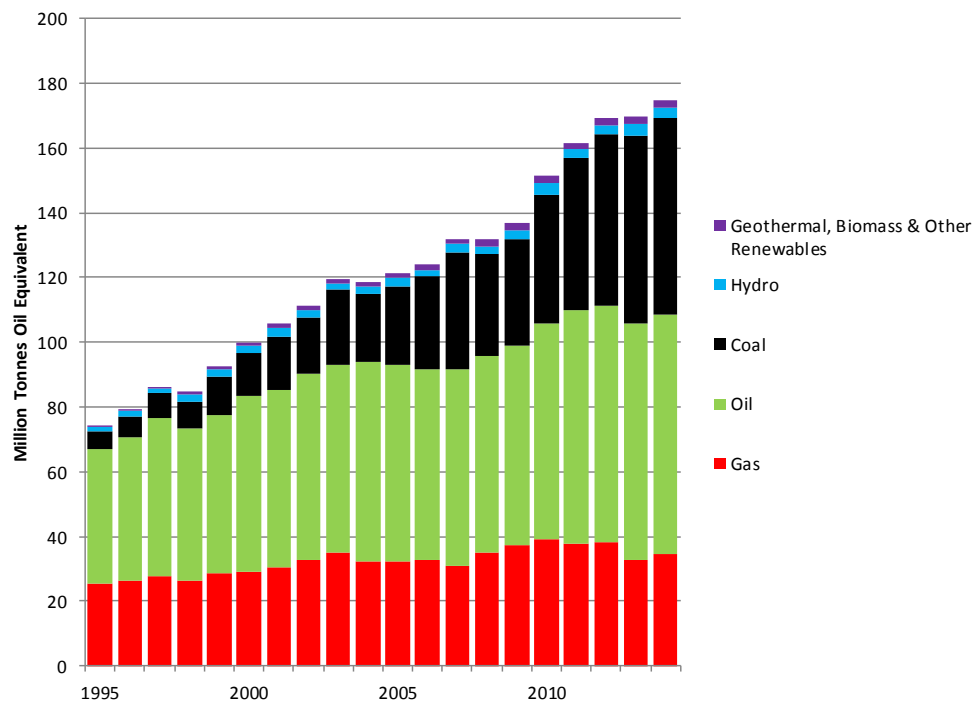
⁷⁹ CIA (2015a)



growth (average 2000-2014 5.3%)⁸⁰, with positive growth maintained through the 2008/2009 financial crisis period. Indonesia was (in 2014) the world's third largest coal producer (after China and the USA)⁸¹ and one of the world's largest coal exporters. Indonesia became an LNG exporter in 1977 with Japan as its first market (see Chapter 1)⁸².

2.6.1 Gas Consumption and Supply

Figure 48: Indonesia Primary Energy Mix 1995-2014



Source: BP (2015)

As Figure 48 shows, gas consumption has been generally stagnant since the early 2000s while overall energy consumption has grown by (on average) 4.1%/year. Coal has been the main beneficiary. Indonesian domestic gas consumption trends are shown in Figure 49. Industry and power generation are the key consumption sectors, which grew at 2.8% and 4%/year respectively on average between 2010 and 2013. Note that in addition to the consumption categories shown in Figure 49, some Indonesian production is flared, consumed as 'own use', gas lift and reinjection, which may explain the difference between the BP Statistical Review data and that in Figure 49.

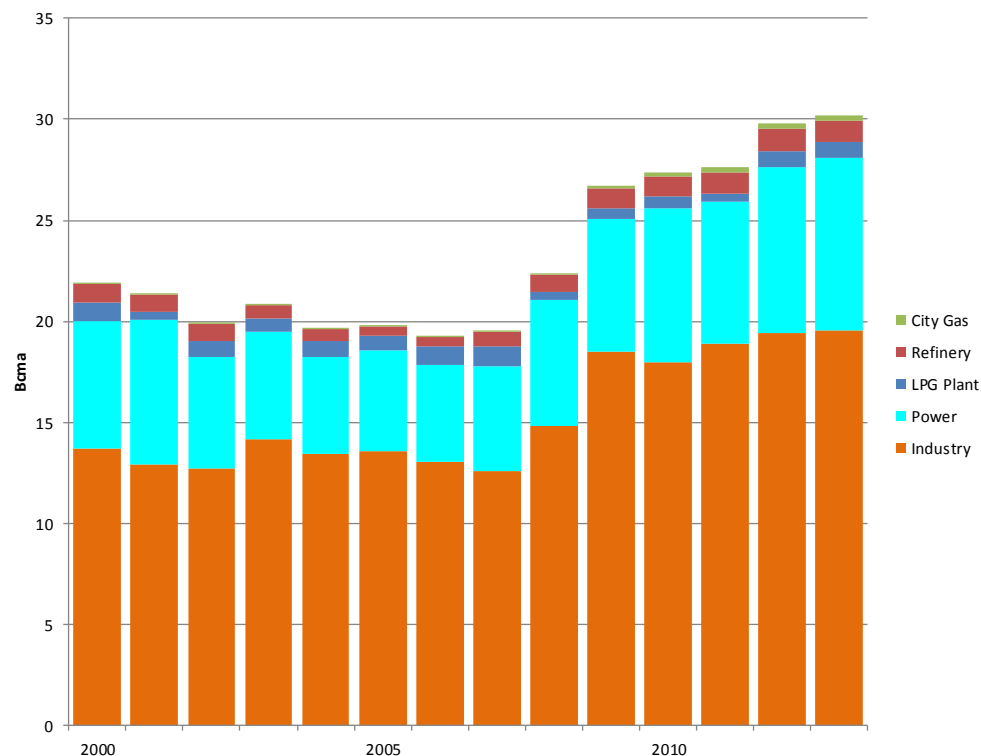
⁸⁰ World Bank (2015)

⁸¹ BP (2015).

⁸² Cedigaz (2004)



Figure 49: Indonesia Domestic Gas Consumption 2000 - 2013



Source: Indonesia (2014), pp. 82 – 83

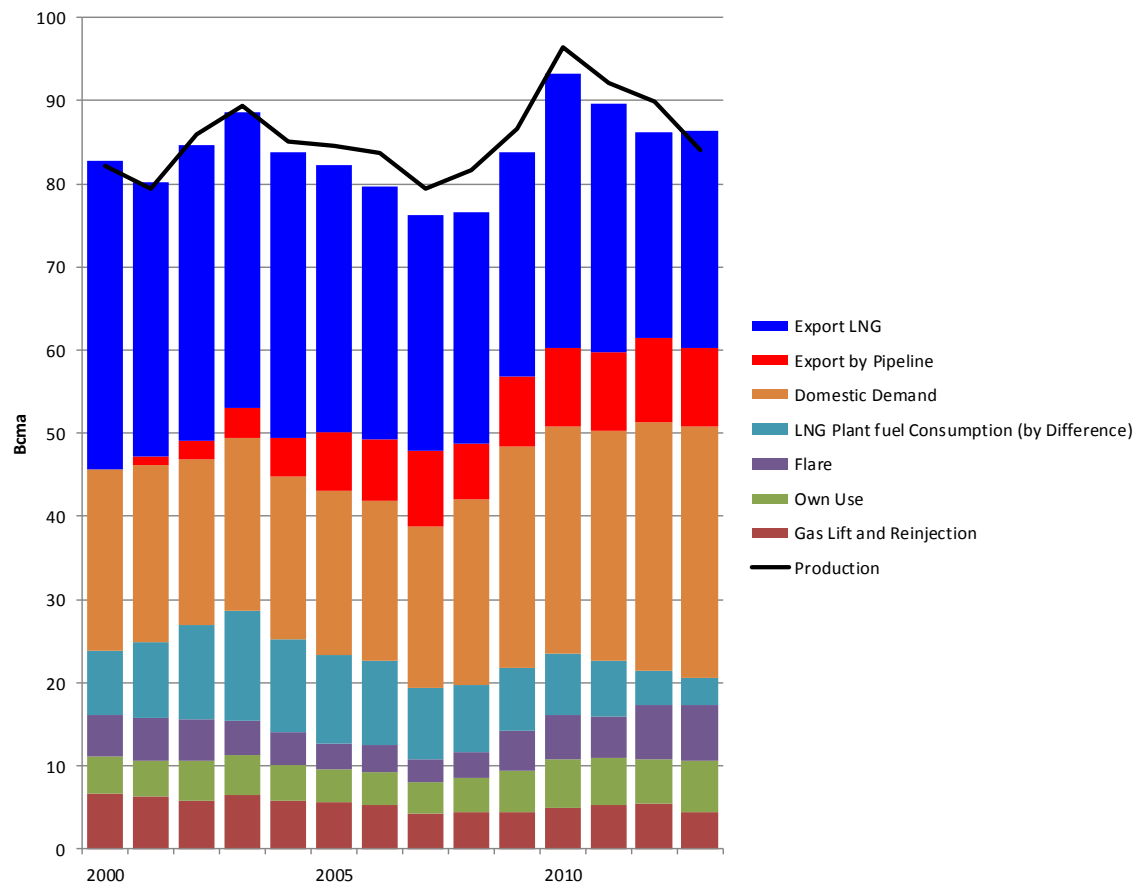
Recent government policy moves to increase gas consumption to displace oil products are described in Seah, S (2014)⁸³. Achieving consistent future gas consumption growth will require the provision of gas supply and distribution infrastructure across the archipelago, and this is progressing.

Figure 50 shows Indonesia's total production and use of gas. Considerable volumes are used to maintain oil field production (Gas Lift and Reinjection & Own Use) and flaring continues. The category 'LNG plant field consumption' appears high but probably includes significant statistical errors. The scale of LNG and pipeline exports is evident.

⁸³ Seah, S. (2014)



Figure 50: Indonesia Production and Consumption of Natural Gas 2000 - 2013

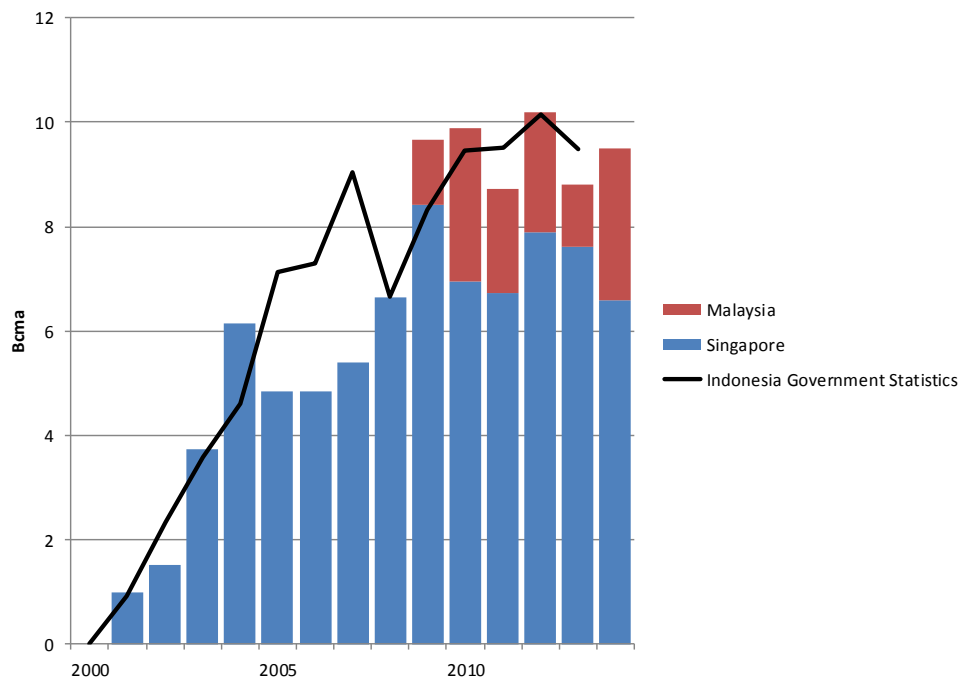


Source: Indonesia (2014), pp. 82 – 83

Indonesia's pipeline exports to Singapore began in 2001 and to Malaysia in 2009 as shown in Figure 51. (Note again there appears some discrepancy between annual exports reported by the BP Statistical Review of World Energy and Indonesia).



Figure 51: Indonesia Production and Use of Natural Gas 2000 - 2013



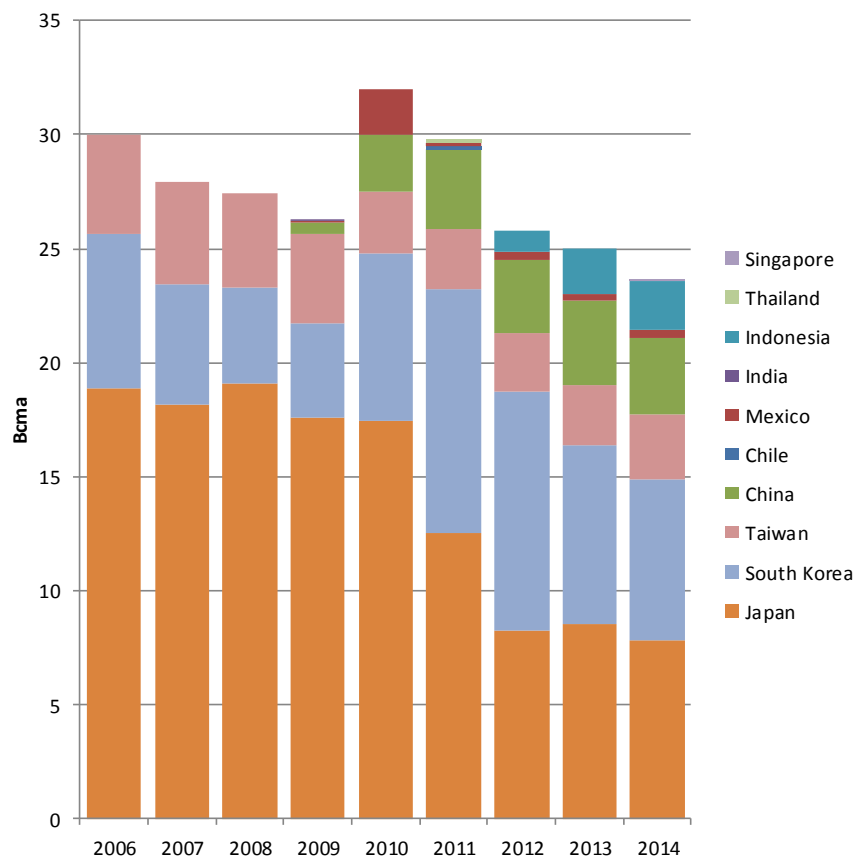
Source: Indonesia (2014), pp. 82 – 83, BP (2015).

LNG exports from the early Bontang (Kalimantan) and Arun (Sumatra) plants declined in the early to mid-2000s as fields supplying feed gas became depleted and domestic demand increased. The Tangguh (Papua) project which started in 2009 to a degree stemmed this LNG export decline. Two new liquefaction plants are under construction in Sulawesi - Donggi-Senoro (2 mtpa) and Sengkang (0.5 mtpa). The Arun export facility on Sumatra is being converted to an import terminal⁸⁴. Indonesia's LNG story is thus evolving into one of intra-archipelago trade as well as being a net exporter of LNG.

⁸⁴ 'Indonesia's share of global LNG supply declines due to global and domestic demand growth', EIA, March 10th 2014, <http://www.eia.gov/todayinenergy/detail.cfm?id=15331>



Figure 52: Indonesia LNG Exports 2006 - 2014



Source: GIIGNL (2014)

Figure 52 shows Indonesia's LNG exports by country of destination. The decline in output from Bontang and Arun is reflected in the lower exports to Japan and Taiwan. The start-up of Tangguh explains the increase in exports to South Korea and the start of exports to China as well as more opportunistic cargoes to Mexico, India, Thailand and Singapore. Of note is the start of trade-flows within the Indonesian archipelago from 2012.

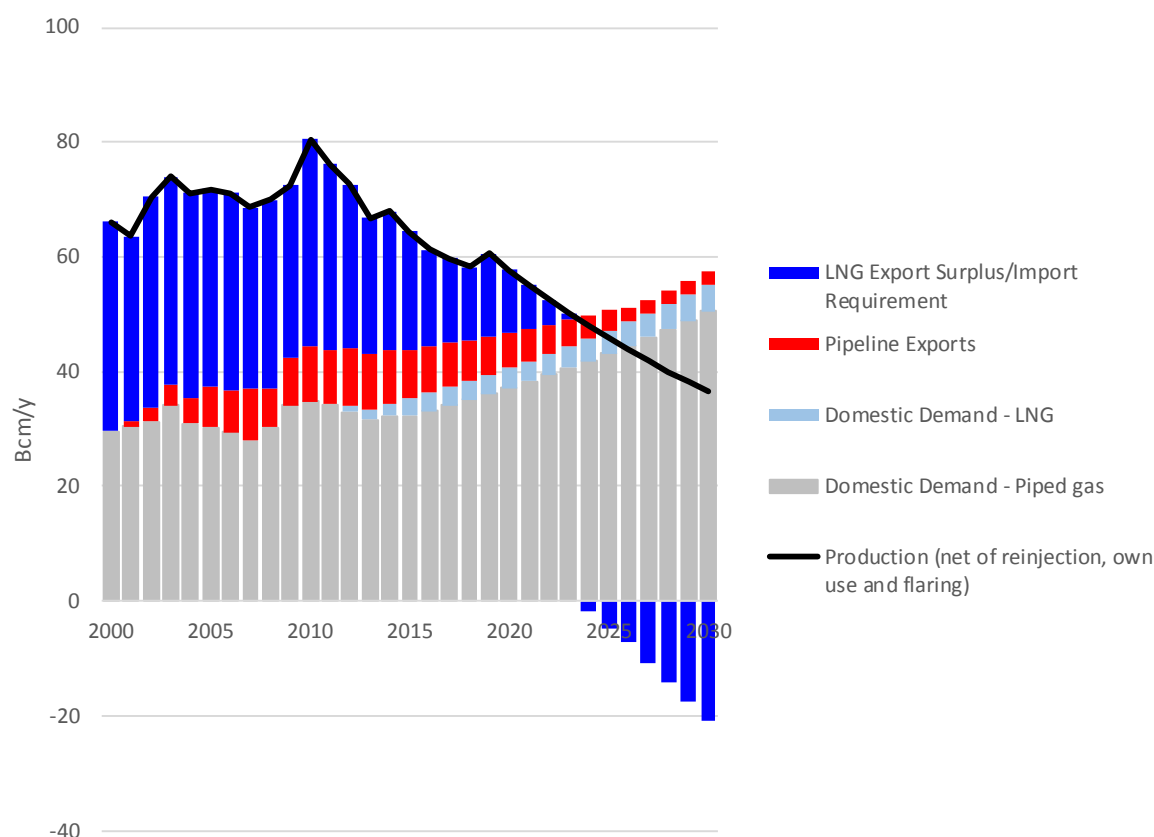
2.6.2 Indonesia Outlook

The IEA⁸⁵ anticipates strong natural gas demand growth in Indonesia especially in the industrial sector; growth between 2015 and 2020 of 4.1% is noted. Figure 53 shows Indonesia's balance with a post-2014 domestic demand growth assumption of just 2.3% per year and pipeline exports to Singapore declining as noted previously. Assuming a future production decline (net of flaring, reinjection and own use) of 5%/year (but with Tangguh expansion – 5.2 bcm/y - starting in 2019), Indonesia would become an LNG net importer by 2023 in the absence of significant new gas discoveries. On these assumptions, its LNG net import requirement by 2025 would be some 5 bcm/y.

⁸⁵ IEA (2015b), P. 41



Figure 53: Natural Gas Balance 2000-2030



Source: Indonesia (2014), pp. 82 – 83, BP (2015), Author's Assumptions

Table 10 shows the outlook for LNG imports (high case) based on Figure 53. A low case was constructed based on an assumption that domestic production in future declines at 2.5%/year (rather than 5%), as a consequence of further exploration success and field development. In the low case Indonesia would still be a net exporter of LNG in 2025.

Table 10: Indonesia LNG Import Outlook

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	3.8	6.5	9.3
	High Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	4.9	7.3	10.7	14.1	17.5	20.8
mtpa	Low Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	2.8	4.8	6.9
	High Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	3.6	5.4	7.9	10.4	12.9	15.3

2.7 Malaysia

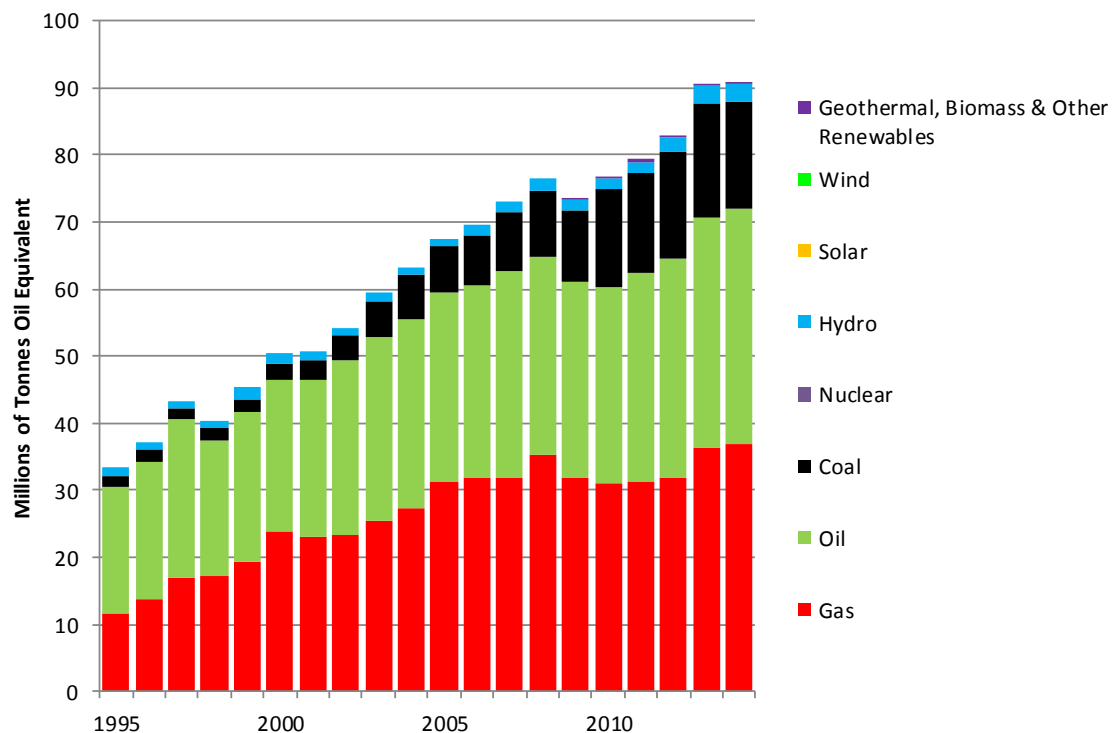
Malaysia's land mass is separated by the South China Sea into two similarly sized regions: Peninsula Malaysia (north of Singapore) and East Malaysia (the northern part of the island of Borneo – excluding Brunei). Although Malaysia saw GDP falling 1.9% in 2009, its average annual GDP growth



from 2000 to 2014 was 5.1%⁸⁶. Malaysia is an open upper-middle income economy. Formerly a producer of raw materials, such as tin and rubber, in the 1970s, Malaysia now has a diversified economy and has become a leading exporter of electrical appliances, electronic parts and components, palm oil, and natural gas.

Malaysia's energy mix is shown in Figure 54. Annual average energy consumption has grown by 4.3% between 2000 and 2014, gas consumption by 4.4% on average. Since 2000 coal consumption has increased significantly although it still amounts to only 17% of the total energy mix.

Figure 54: Malaysia Energy Balance 1995 - 2014



Source: BP (2015)

2.7.1 Gas Consumption and Supply

Malaysia's oil and gas industry commenced with Shell drilling an oil well in Sarawak in 1910. The offshore discovery of large natural gas reserves in the 1960s resulted in the construction of the Bintulu liquefaction plant⁸⁷. Gas resources are chiefly offshore to the north west of Peninsula Malaysia and north of the Sarawak region. More than 80% of domestic gas consumption is in Peninsula Malaysia. LNG exports commenced in 1983 and pipeline gas exports to Singapore in 1992. Malaysia imports pipeline gas from Indonesia, the Malaysia/Thailand Joint Development Area, and the Malaysia-Vietnam Commercial Arrangement Area (CAA)⁸⁸. Malaysia also began importing LNG in 2013. (See Figure 55).

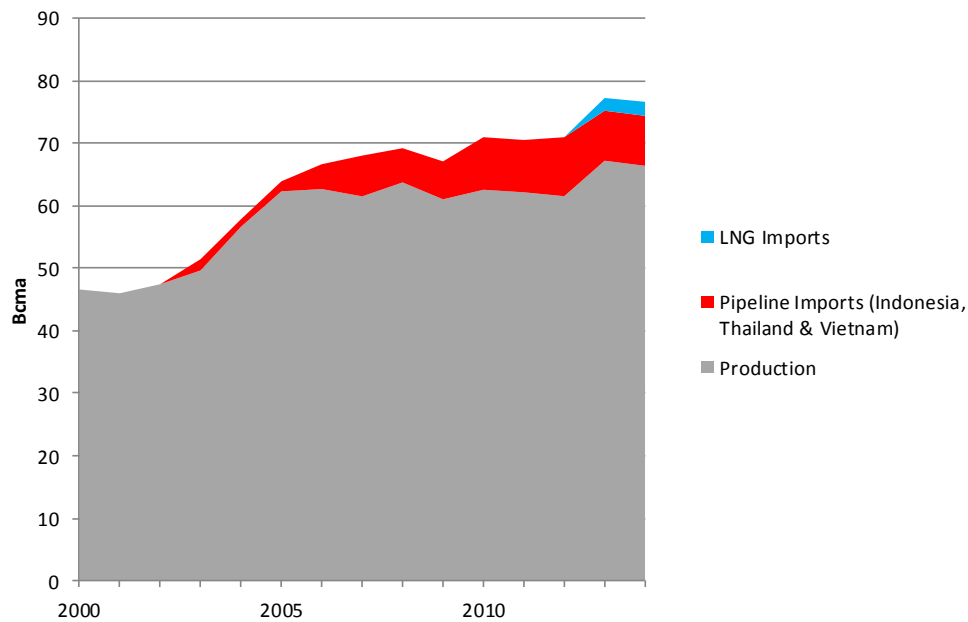
⁸⁶ World Bank (2015)

⁸⁷ 'The History of Shell in Malaysia', Shell Website, <http://www.shell.com.my/aboutshell/who-we-are/history/malaysia.html>

⁸⁸ Malaysia (2014a), P.35



Figure 55: Malaysia Gas Supply: Production, Pipeline and LNG imports 2000-2014

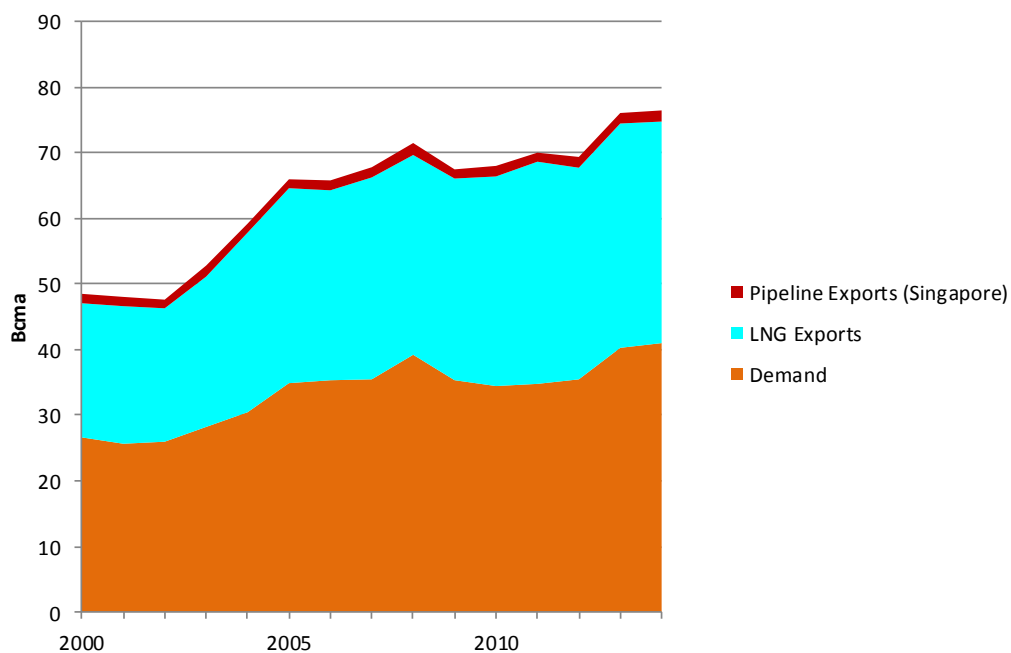


Sources: BP Statistical Review of World Energy, GIIGNL, Malaysia Energy Statistics Handbook 2014, P. 23.

Note: Pipeline Supplies for 2013 and 2014 are estimates.

Figure 56 shows demand and exports of LNG and pipeline gas (to Singapore).

Figure 56: Malaysia Gas Demand and Exports: Consumption, Pipeline and LNG Exports 2000 - 2014



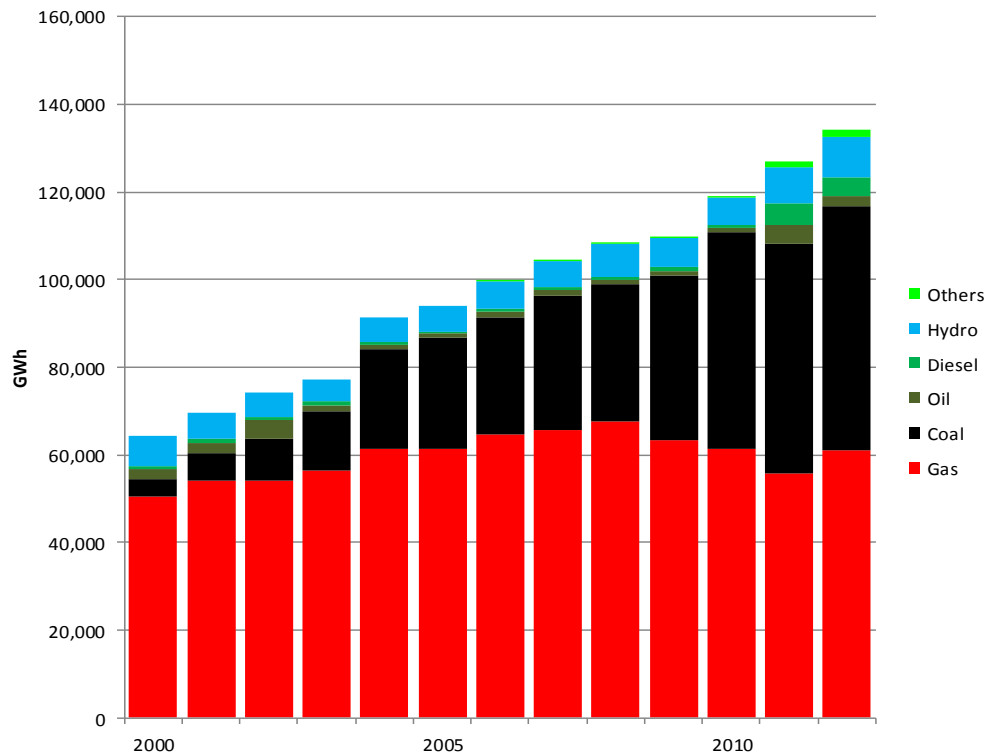
Sources: BP (2015), GIIGNL (2014), Malaysia (2014b), P. 23.

Note: Differing data sources result in a minor mismatch between Figures 55 and 56 in some years.



Gas consumption by sector in Malaysia in 2012 comprised: Power Generation 56%, Non-Energy 23%, Industry 20%, Transportation 1% and Residential and Commercial 0.1%⁸⁹. Of the industrial demand, 55% was consumed in rubber, food, beverage and tobacco, 20% in metal and non-metallic mineral products, 8% in chemicals and 'others' 17%⁹⁰. This suggests that, in the absence of a high-growth technology-based industrial sector, Malaysia's future demand is primarily driven by the power sector, although Figure 57 suggests that coal will supply incremental power demand growth in the future.

Figure 57: Malaysia Power Generation by Fuel/Technology 2000 - 2012



Source: Malaysia (2014b), P. 33

Malaysian LNG imports in 2013 and 2014 were between 2 and 2.3 bcm from a range of countries, including Algeria, Brunei, Nigeria and Yemen, primarily on the basis of spot or short term contracts.

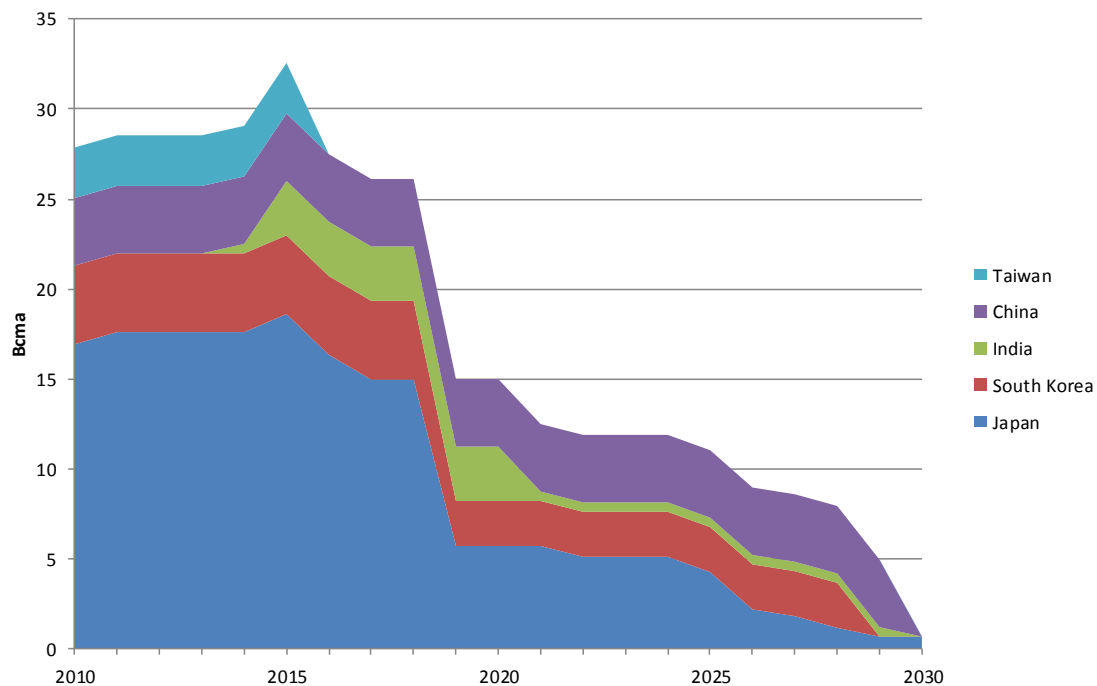
LNG exports have grown slowly since 2006 to around 35 bcm/y and are primarily to Japan, South Korea (declining), and Taiwan. Chinese deliveries have grown since 2009 and other minor spot trades make up the difference. Future LNG contractual commitments fall significantly towards the end of the 2010s as shown in Figure 58.

⁸⁹ Malaysia (2014a), P. 22

⁹⁰ Malaysia (2014a), P. 23



Figure 58: Malaysia LNG Contract ACQs 2010-2030



Source: GIIGNL (2014)

2.7.2 Outlook for Malaysian Gas

The outlook for natural gas in Malaysia is coloured by its maturity as a gas producing province (new resources generally in deeper water) and the low regulated price in the Malaysian domestic market. Coal has already established itself as the fuel to supply incremental power generation. Whilst higher regulated gas prices would stimulate more domestic gas production this would enhance the competitiveness of coal in the power sector, absent a more specific carbon abatement policy. Malaysia's 2014 CO₂ emissions for reference were 4.3 times higher than in 1990⁹¹. Malaysia has embarked upon the use of LNG imports to supply the Malacca region on the Malaysian Peninsula and has plans for further import terminals; one in the Sabah region (Island of Borneo) and another at Johor on the Malaysian Peninsula⁹².

In addition to its existing land-based liquefaction facilities (Satu, Dua and Tiga), Malaysia is progressing two or more small floating LNG production facilities offshore Sarawak and Sabah⁹³.

An illustrative supply outlook for Malaysia is shown in Figure 59. This assumes a decline in domestic production of 2.5%/year from 2018, a gradual reduction in pipeline imports but a notional growth of 0.25 bcm/y in LNG imports.

⁹¹ BP (2015)

⁹² EIA (2014), P.13

⁹³ EIA (2014), P.13

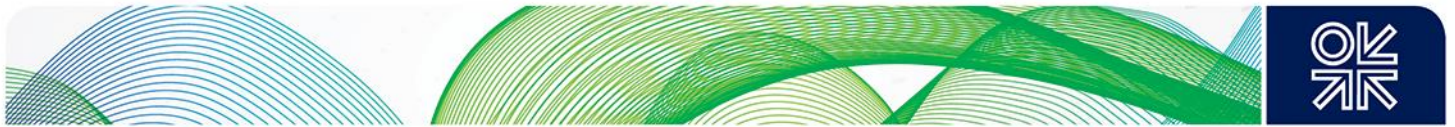
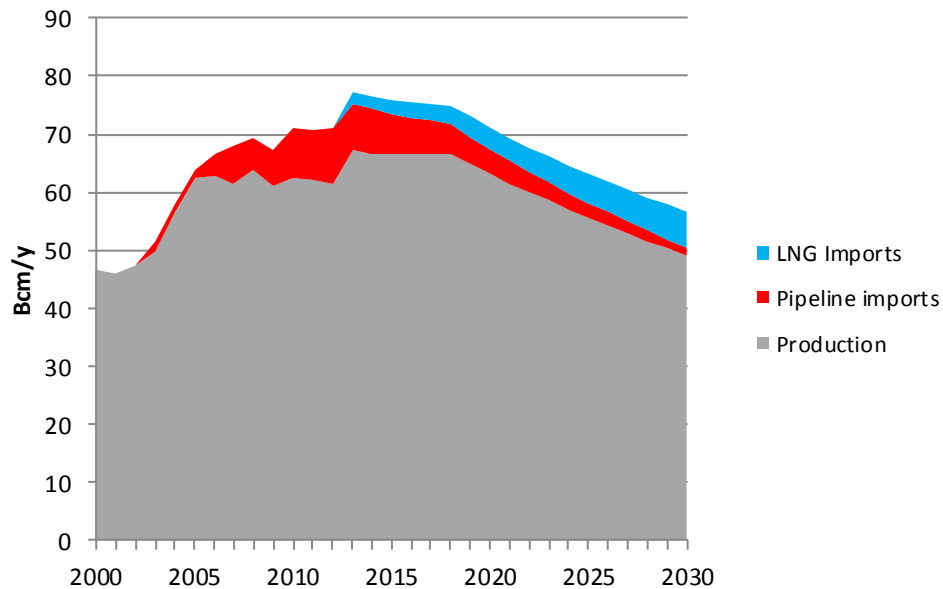


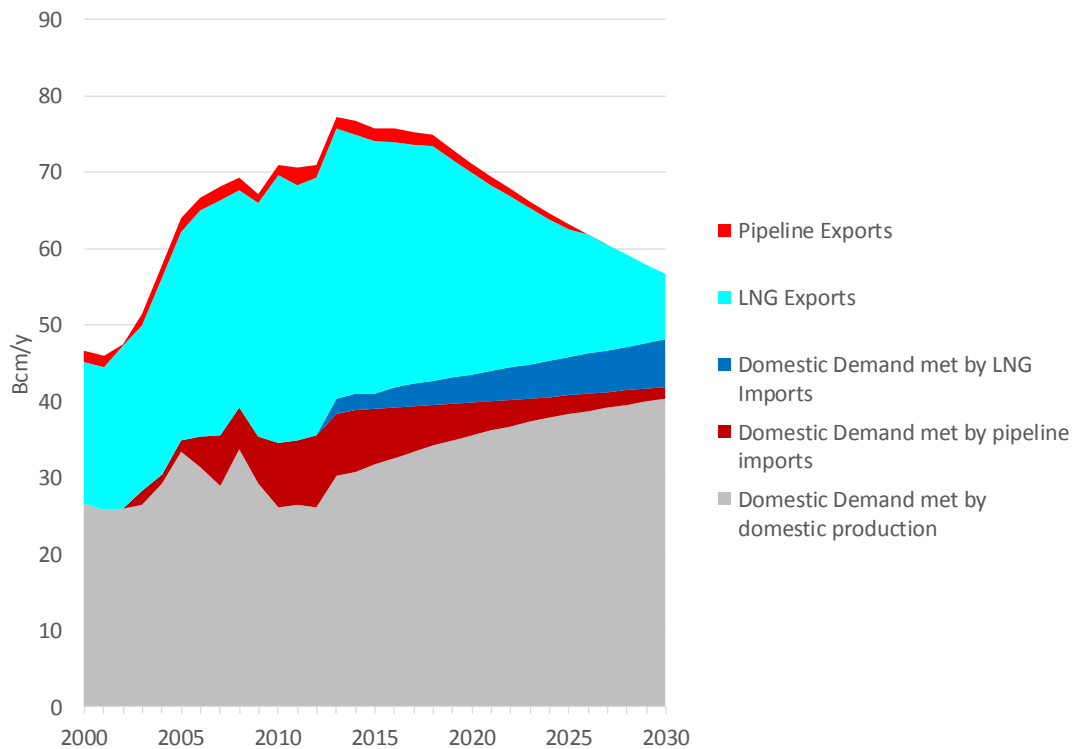
Figure 59: Malaysia Supply Outlook to 2030



Sources: BP (2015), GIIGNL (2014), Malaysia (2014b), P. 23. Author's Assumptions

On the Demand side, Figure 60 shows an assumed domestic demand growth of 1%/year, a tapering in pipeline exports and LNG exports as a balancing item. LNG exports in all years to 2030 are in excess of the aggregate ACQs of existing contracts.

Figure 60: Malaysia Demand and Export Outlook to 2030



Sources: BP (2015), GIIGNL, Malaysia (2014b), P. 23, Author's Assumptions



The outlook for Malaysia is therefore one of a significant participant in LNG trade into the 2020s, but one whose LNG export surplus is progressively declining due to the maturity of its gas resource.

For the cases considered, Malaysian LNG import volumes are as shown in Table 11. To 2025 there is no difference in LNG imports.

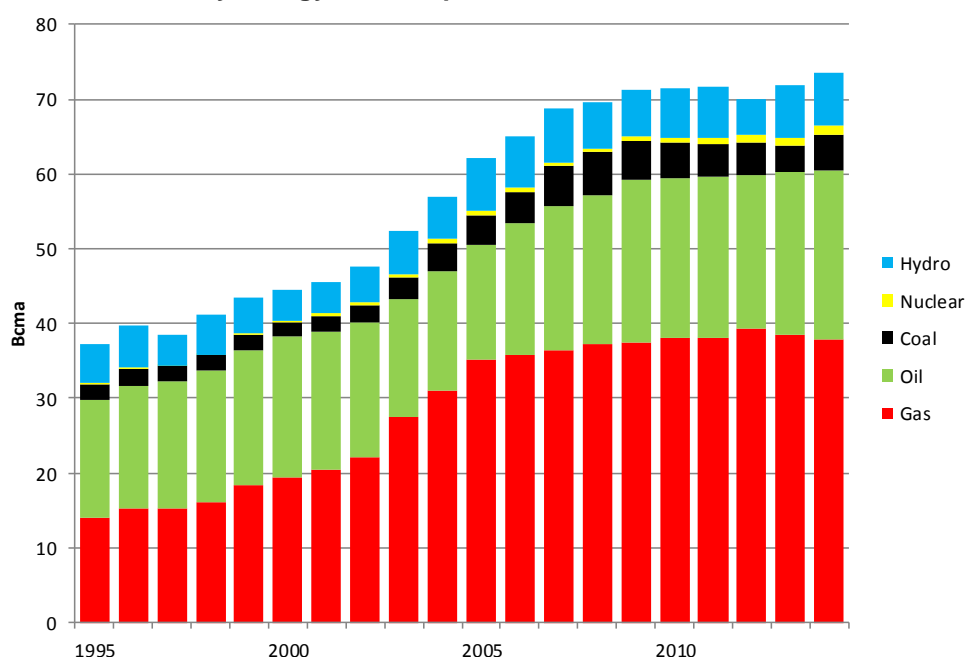
Table 11: Malaysia LNG Import Outlook

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	0.0	0.0	0.0	2.0	2.2	2.1	2.7	3.0	3.2	3.5	3.7	4.0	4.2	4.5	4.7	5.0	5.2	5.5	5.7	6.0	6.2
	High Case	0.0	0.0	0.0	2.0	2.2	2.1	2.7	3.0	3.2	3.5	3.7	4.0	4.2	4.5	4.7	5.0	5.2	5.5	5.7	8.2	10.7
mtpa	Low Case	0.0	0.0	0.0	1.5	1.7	0.5	2.0	2.2	2.4	2.6	2.8	2.9	3.1	3.3	3.5	3.7	3.9	4.0	4.2	4.4	4.6
	High Case	0.0	0.0	0.0	1.5	1.7	1.5	2.0	2.2	2.4	2.6	2.8	2.9	3.1	3.3	3.5	3.7	3.9	4.0	4.2	6.0	7.9

2.8 Pakistan

While Pakistan's GDP growth from 2000 to 2014 averaged 4.2%/year⁹⁴ the country saw a degree of stagnation post 2008. Pakistan's problems include: 'corruption, lack of accountability, and lack of transparency continue to pervade all levels of government, politics, and the military'^{95,96}. Agriculture, industry and services in 2013 contributed 25.3%, 21.6% and 53.1% to GDP respectively⁹⁷.

Figure 61: Pakistan Primary Energy Consumption 1995-2014



Source: BP (2015)

From Figure 61, Pakistan's total energy consumption has plateaued since 2008.

⁹⁴ World Bank (2015)

⁹⁵ Gomes, I (2013)

⁹⁶ 2015 Index of Economic Freedom', <http://www.heritage.org/index/country/pakistan>

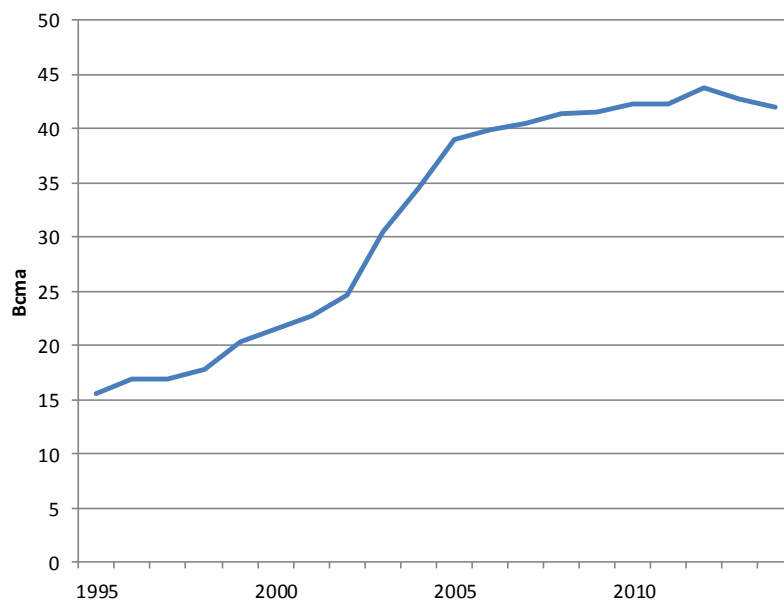
⁹⁷ CIA (2015b)



2.8.1 Gas Consumption and Supply

Gas has consistently formed 50 to 55% of the energy mix, with coal between 5 and 8%. In 1952 some 10 tcf of gas was discovered in Balochistan. In addition to state-controlled companies, several international companies are currently present in the Pakistan upstream. ENI is the largest international player with production operations and participation in several offshore exploration blocks. In 2014, Pakistan had no export or import trade flows in gas; its production and consumption from 1995 to 2014 is shown in Figure 62.

Figure 62: Pakistan Natural Gas Production and Consumption 1995 – 2014



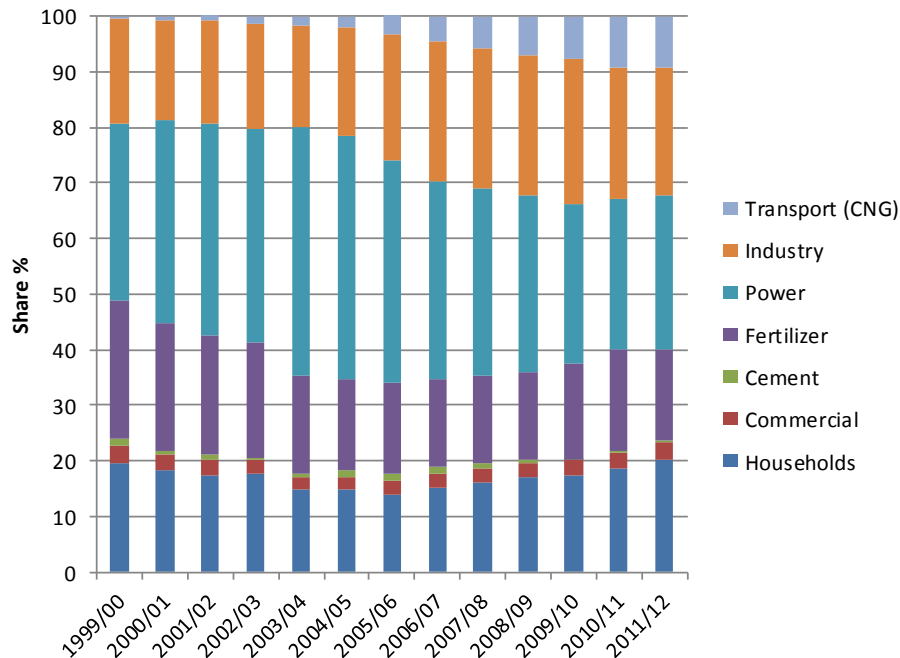
Source: BP (2015)

Pakistan has latent demand potential which is constrained by available supply. Gomes⁹⁸ cites un-met demand in 2012 of between 18 and 26 bcm/y, comprising potential for fuel oil switching in power generation and industry and unutilised capacity. The scope for additional demand above available domestic production is estimated at 13-26 bcm/y in 2015, rising to 41-49 bcm/y in 2020. Figure 63 shows the percentage share of gas consumption in various sectors in the fiscal years 1999/2000 to 2011/2012.

⁹⁸ Gomes, I (2013)



Figure 63: Pakistan Gas Consumption Shares 1999/2000 – 2011/2012



Source: Pakistan (2013), P. 191

In the early 2010s an assessment of Yet-to-Find reserves on an unrisks basis suggested 3.6 billion of barrels of oil and 66.3 tcf of gas. However, over the last few years there has actually been a decline in the country's reported gas reserves. The situation is not helped by the low domestic price of gas – in 2012 some \$5/MMBtu⁹⁹.

The Iran Pipeline Project was first discussed in the early nineties. Plans to include India as a secondary market foundered in the 2000s. Although it is alleged that Iran has completed 900 of the 1,150 km of this pipeline on its own territory, Pakistan's section has yet to be built. While some of the agreement suite appears to have been concluded, pricing has been revisited several times¹⁰⁰. This said, the 2015/2016 rapprochement on Iranian nuclear issues and potential for lifting of sanctions might in time allow the project to achieve completion¹⁰¹. Initial gas volumes are planned to be 7.8 bcm/y. The Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline project was initiated in 2004. The project was designed as an alternative to the Iranian Pipeline Project and while it has US State Department support, in practical terms the security situation in Afghanistan renders its implementation 'on hold' for the foreseeable future.

In March 2015 Pakistan began importing LNG from Qatar and from July 2015, Nigeria. Using a floating storage and re-gasification unit and ship-to-ship transfer, the gas is injected into the grid in the vicinity of Karachi. In 2015, some 1.5 bcm was imported. Full regas capacity of this system/configuration is 4 bcm/y¹⁰². Pakistan has signed a 15 year contract with Qatar for between 2

⁹⁹ Gomes, I (2013), pp 15, 25

¹⁰⁰ Gomes, I (2013), P.30

¹⁰¹ 'Will the Iran Deal Help the Iran-Pakistan Pipeline Project?', The Diplomat, July 28, 2015, <http://thediplomat.com/2015/07/will-the-iran-deal-help-the-iran-pakistan-pipeline-project/>

¹⁰² 'Pakistan to join LNG Importers club soon', March 10th 2015, LNG World News, <https://www.lngworldnews.com/pakistan-to-join-lng-importers-club-soon/>

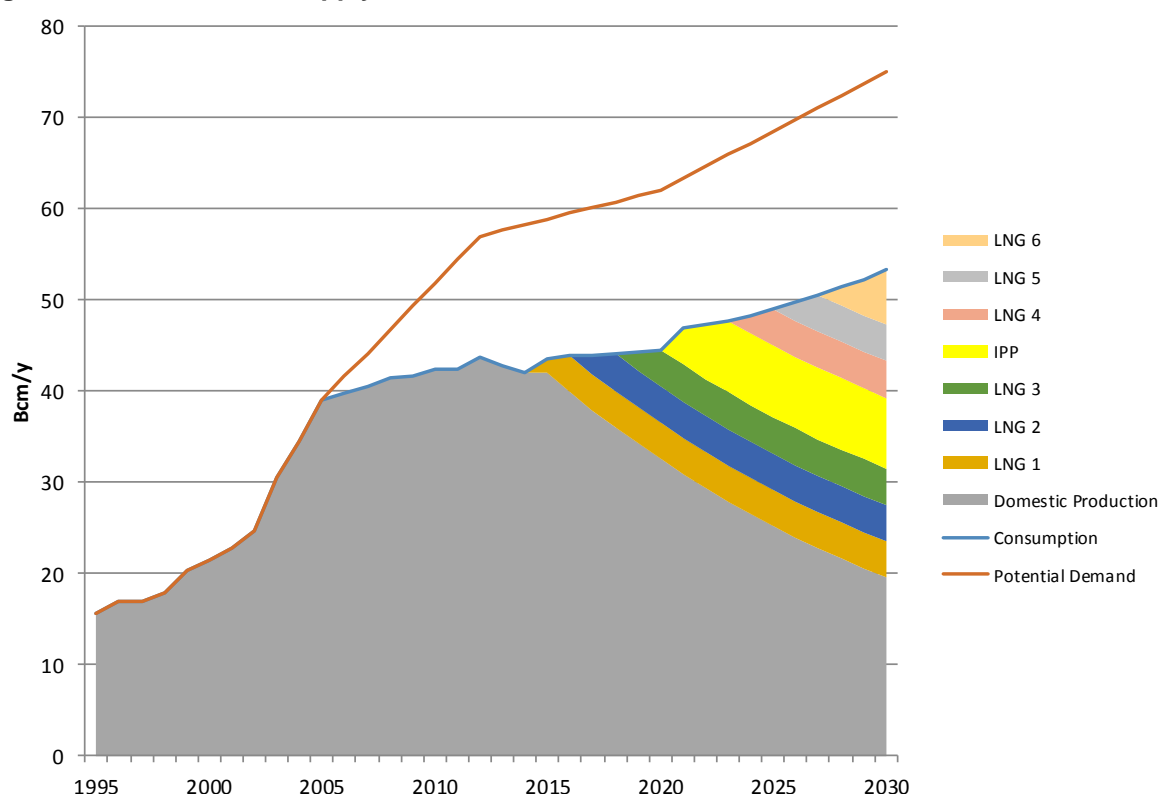


and 4 bcm/y at prices of around \$7/MMBtu at mid-2015 oil prices¹⁰³. Plans are advanced to build a second terminal of around 4 bcm/y capacity, operational in 2016/2017.

2.8.2 Pakistan Outlook

Figure 64 shows an illustrative outlook for Pakistan's gas supply and demand position to 2030. The notional 'Potential Demand' is guided by research in Gomes, I (2013). Future domestic production assumes a decline of 5%/year from 2016. Actual consumption (as it has been for the past few years) will be a function of gas supply availability (and the ability of consumers to pay a cost reflective/market price). This is predicated upon the successful conclusion of current and future LNG import projects and the Iran Pakistan Pipeline (IPP).

Figure 64: Pakistan Gas Supply and Demand Outlook 1995 - 2030



Sources: Gomes, I (2013), P 11, BP (2015), Author's Assumptions.

While highly speculative, this view indicates an LNG import requirement for 2020 and 2025 of 12 and 16 bcm/y respectively, although this would not satisfy the potential country demand. This 'lagged response' will be due to a lack of focussed policy and detractions from powerful lobbies, project execution delays, including finance concerns and end-user payment collection issues.

Pakistan LNG import volumes are as shown in Table 12. The high case corresponds to the discussion above. A low case assumes a domestic production decline of 2.5%/year.

¹⁰³ 'Pakistan to sign 15 year deal to import gas from Qatar – official', ARY NEWS, July 29th, 2015, <http://arynews.tv/en/pakistan-to-sign-15-year-deal-to-import-gas-from-qatar-official/>



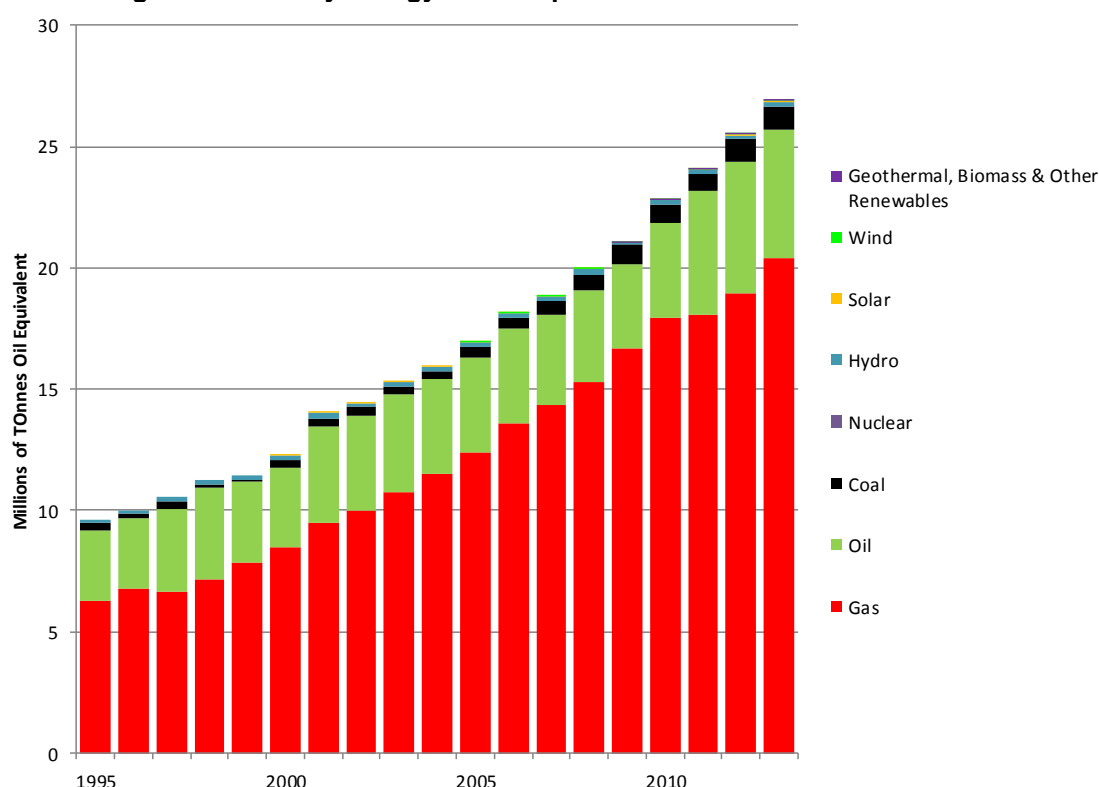
Table 12: Pakistan LNG Import Outlook

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	0.0	0.0	0.0	0.0	0.0	1.4	4.0	4.0	6.0	8.0	10.0	12.0	12.0	12.0	12.0	14.0	14.0	14.0	14.0	14.0	14.0
	High Case	0.0	0.0	0.0	0.0	0.0	1.4	4.0	6.0	8.0	10.0	12.0	12.0	12.0	12.0	14.0	16.0	18.0	20.0	22.0	24.0	26.0
mtpa	Low Case	0.0	0.0	0.0	0.0	0.0	1.1	2.9	2.9	4.4	5.9	7.4	8.8	8.8	8.8	8.8	10.3	10.3	10.3	10.3	10.3	10.3
	High Case	0.0	0.0	0.0	0.0	0.0	1.1	2.9	4.4	5.9	7.4	8.8	8.8	8.8	8.8	10.3	11.8	13.2	14.7	16.2	17.6	19.1

2.9 Bangladesh

Bangladesh is one of the world's most densely populated countries; poverty is deep and widespread, however in recent years it has reduced population growth and improved health and education. The major employer is agriculture. The country is trying to diversify its economy, with industrial development a priority. Bangladesh spent 15 years under military rule and, although democracy was restored in 1990, the political scene remains volatile. Bangladesh's GDP growth has averaged 5.7%/year from 2000 to 2014, with no years of negative growth¹⁰⁴. Pakistan Petroleum Limited discovered gas at Sylhet in 1955, with commercial production commencing in 1960 with the supply of 4 mmcf/d to a cement factory¹⁰⁵.

Figure 65: Bangladesh Primary Energy Consumption 1995–2014



Source: BP (2015)

¹⁰⁴ World Bank (2015)

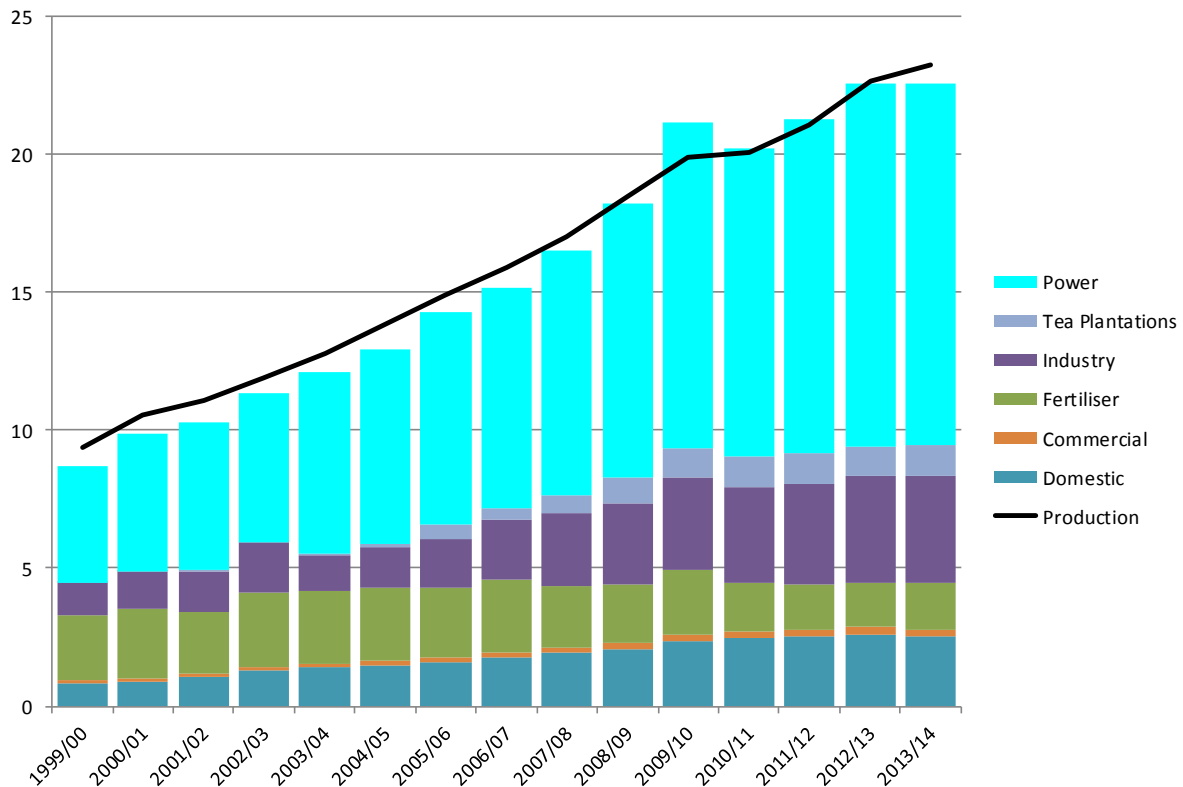
¹⁰⁵ Gomes, I (2013), P. 42



From Figure 65 it is evident that natural gas is the predominant primary energy source with coal playing a minor if growing role.

2.9.1 Gas Consumption and Supply

Figure 66: Bangladesh Gas Consumption 1995 – 2014



Source: Bangladesh (2014)

From Figure 66 it would appear that while most categories of demand have stabilised since 2009/10, power generation is still on a generally rising trend. Potential gas demand in 2015 is some 10 bcm above available supply in 2015¹⁰⁶. However, with limited future prospectivity and low domestic prices, the outlook for increased domestic production is not encouraging.

In 1997, Bangladesh expressed interest in a project to import pipeline gas from Myanmar, however this was not progressed and, given Myanmar's future gas pipeline export obligations, this is unlikely to proceed in the future.

In 2010 Bangladesh announced its intention to build an LNG import terminal for 5 bcm/y, but this did not materialise due to issues of buyer credit worthiness, poor infrastructure connectivity and the lack of a strong project sponsor/financing¹⁰⁷. In 2015 however, Reliance Power signed an MOU to develop a floating regas unit and associated power plant¹⁰⁸. In the absence of sufficient gas to meet latent demand, Bangladesh is turning to coal and fuel oil in power generation.

¹⁰⁶ Gomes, I (2013), P. 47

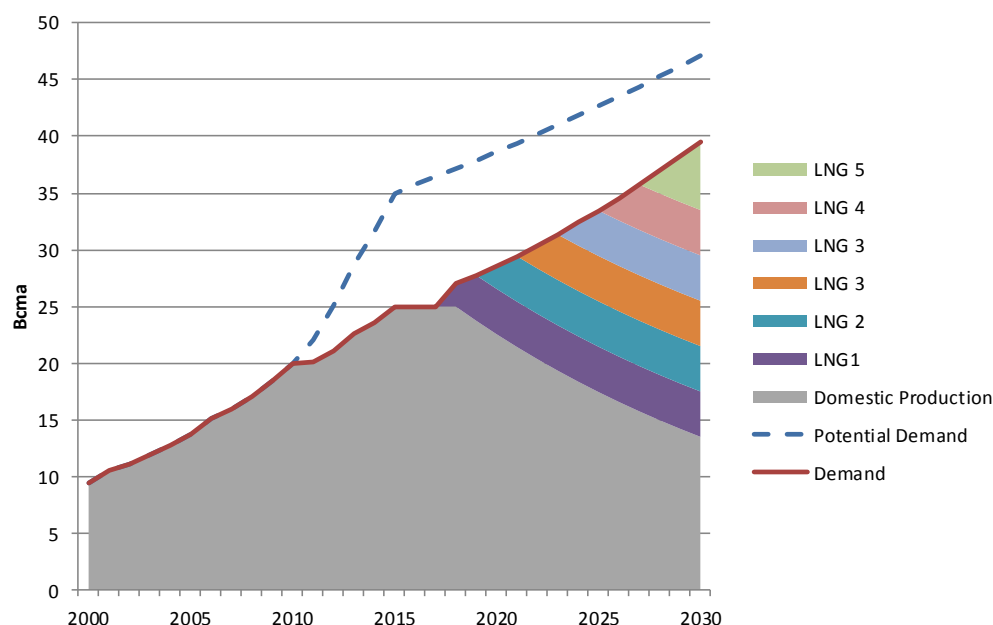
¹⁰⁷ Gomes, I (2013), pp. 60, 61

¹⁰⁸ 'Reliance Power to develop LNG Power Project', LNG Industry 8th June 2015, <http://www.lngindustry.com/liquid-natural-gas/08062015/Bangladesh-LNG-power-project-moving-forward-909/>



2.9.2 Bangladesh Outlook

Figure 67: Bangladesh Potential Gas Supply and demand to 2030



Sources: BP (2015), Gomes, I (2013), Author's Assumptions

Figure 67 shows a potential outlook for Bangladesh supply and demand to 2030. Assuming domestic production declines at 5%/year from 2018, LNG imports could maintain the recent trend of gas consumption growth, although probably leaving substantial 'unmet' demand potential. Bangladesh LNG import volumes are as shown in Table 13. The high case corresponds to the discussion above. A low case assumes a domestic production decline of 2.5%/year.

Table 13: Bangladesh LNG Import Outlook

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	4.0	4.0	4.0	6.0	8.0	8.0	10.0	12.0	14.0	16.0	18.0
	High Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.0	22.0	24.0	26.0
mtpa	Low Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	2.9	2.9	2.9	4.4	5.9	5.9	7.4	8.8	10.3	11.8	13.2
	High Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	2.9	4.4	5.9	7.4	8.8	10.3	11.8	13.2	14.7	16.2	17.6	19.1

2.10 Vietnam

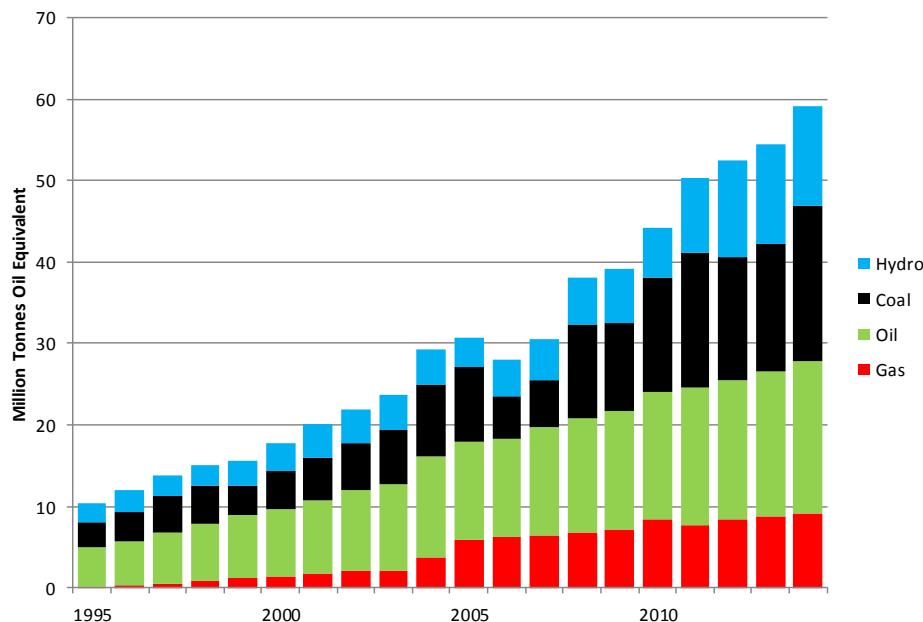
Vietnam has seen consistent high GDP growth with an annual average of 6.4% in the period 2000 to 2014¹⁰⁹. The country has been transitioning from a centrally-planned economy since 1986. Agriculture's share of economic output has shrunk from about 25% in 2000 to 18% in 2014, while industry's share increased from 36% to 38% in the same period. State-owned enterprises now account for about 40% of GDP. Vietnam joined the WTO in 2007, which has promoted more

¹⁰⁹ World Bank (2015)



competitive, export-driven industries. Vietnam's economy continues to face challenges from an undercapitalized banking sector and non-performing loans weigh heavily on banks and businesses¹¹⁰.

Figure 68: Vietnam Primary Energy Consumption 1995 – 2014



Source: BP (2015)

2.10.1 Gas Consumption and Supply

The modern natural gas industry was born in 1995, with the production of associated gas from the Bach Ho oil field to the Ba Ria Power Plant which had an output of under 3 MMcm/d. In 2008, Vietnam used about 90% of natural gas production for power generation with the remainder supplying the industrial and fertilizer sectors. Gas made up about 50% of the power sector's generation requirements in 2010. Gas markets could expand in the central and northern areas of Vietnam once the pipeline infrastructure develops¹¹¹. Vietnam's National Gas Master Plan projects that gas consumption in the country will increase to over 13 bcm/y by 2015. In 2013, the IEA expected Vietnam's gas production to rise to 13 bcm/y (2014 production 10.2 bcm/y¹¹²) and remain at 12 bcm/y till 2035. PetroVietnam predicts there will be a gas supply gap of 13 bcm/y by 2025 as demand outstrips supply in the country

2.10.2 Vietnam Outlook

Vietnam has been expected to become an LNG importer for some while, however its two planned regas terminal projects have been subject to rolling delays. The country had been expected to receive its first cargo in 2018 or 2019 based on expectations that a PetroVietnam subsidiary had hoped to award its first LNG contract in 2015¹¹³. The LNG is intended to be sold to industrial users and fertilizer plants that buy gas at a price linked to alternative fuels such as oil, close to the world market price for LNG. The reality of Vietnamese LNG imports appears however to be subject to rolling delays at the time of writing.

¹¹⁰ CIA (2015a)

¹¹¹ EIA (2012)

¹¹² BP (2015)

¹¹³ 'Vietnam will need imports, but again delays its first LNG', Alaska Natural Gas Transportation Projects, December 8th, 2014, <http://www.arcticgas.gov/2014/vietnam-will-need-imports-but-again-delays-its-first-lng>



A low and high case for LNG imports is shown in Table 14, assuming a 4%/year future demand increase and a 2.5% and 5% decline respectively in domestic production post 2020.

Table 14: Vietnam LNG Import Outlook

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bcm/y	Low Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.7	2.6	3.5	4.4	5.3	6.2	7.1	8.1	9.1
	High Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	2.3	3.5	4.6	5.7	6.9	8.0	9.1	10.3	11.4
mtpa	Low Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.3	1.9	2.6	3.2	3.9	4.6	5.2	6.0	6.7
	High Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.7	2.6	3.4	4.2	5.1	5.9	6.7	7.6	8.4

2.11 Conclusions - More Recent and Emerging Asian LNG Markets

Whilst it is difficult to draw common conclusions for such a diverse group of countries, it is perhaps worth grouping these in terms of three drivers which will determine their future LNG import requirements.

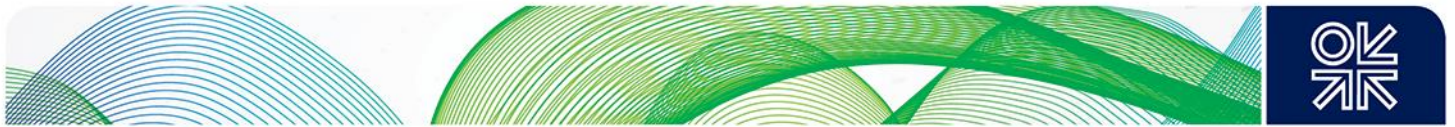
The first is the likely/impending decline in existing domestic production or pipeline gas supplies. This is especially relevant where such supplies of natural gas historically have given rise to the situation where gas has become a major share of the energy mix and where this would be difficult to markedly reduce in the space of 5 to 10 years.

Countries where a **decline in domestic production or pipeline gas supplies** will likely lead to increased LNG imports to 2025 are: Singapore (pipeline supply), Indonesia, Pakistan, Bangladesh, Thailand, Malaysia and Vietnam.

The second driver is **uncertainty around the future energy mix** and government policy. Thus Taiwan and China have the potential for increased LNG imports depending on their choice of coal dependency levels (and GHG emission targets). This category also includes Thailand, India, Malaysia, Pakistan and Bangladesh insofar as they may be unable to achieve acceptable (to other COP21 parties and domestic populations) energy mixes without significantly increasing LNG imports to displace coal, especially if renewables targets and energy efficiency goals are not met.

The third driver relates to **investment frameworks and regulated domestic gas price levels**. If these are deficient they may slow the development of domestic gas resource but give rise to increased LNG imports (albeit these may cost more in the short to medium term). Examples here are: Bangladesh, Pakistan, Vietnam, Malaysia, India and Thailand.

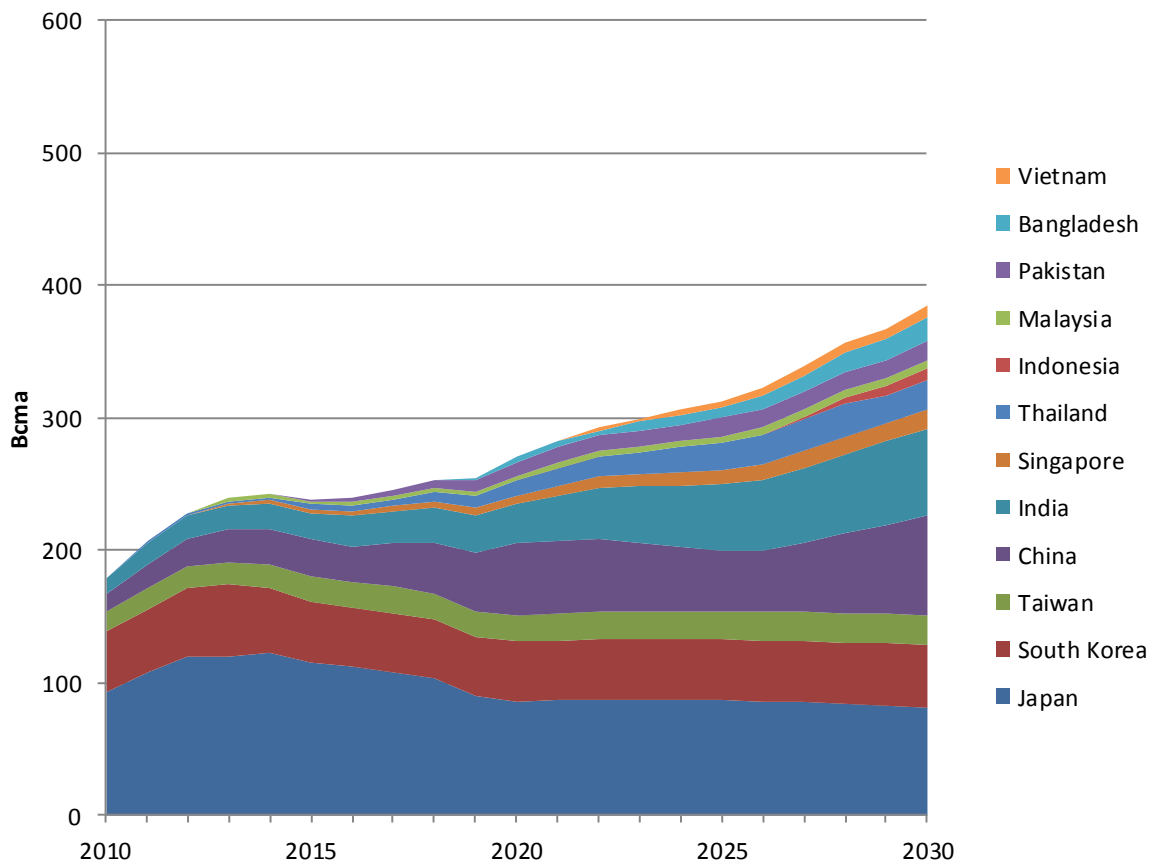
Note that some recent and emerging LNG importing countries appear in more than one of the above categories.



3. Summary and Conclusions

The preceding Chapters of this paper have reviewed the range of LNG import requirements for the Asian markets, whether they are existing or prospective importers. Where possible a 'low' and 'high' case has been derived for each country. The low case for Asia in total is shown in Figure 69 and the high case in Figure 70.

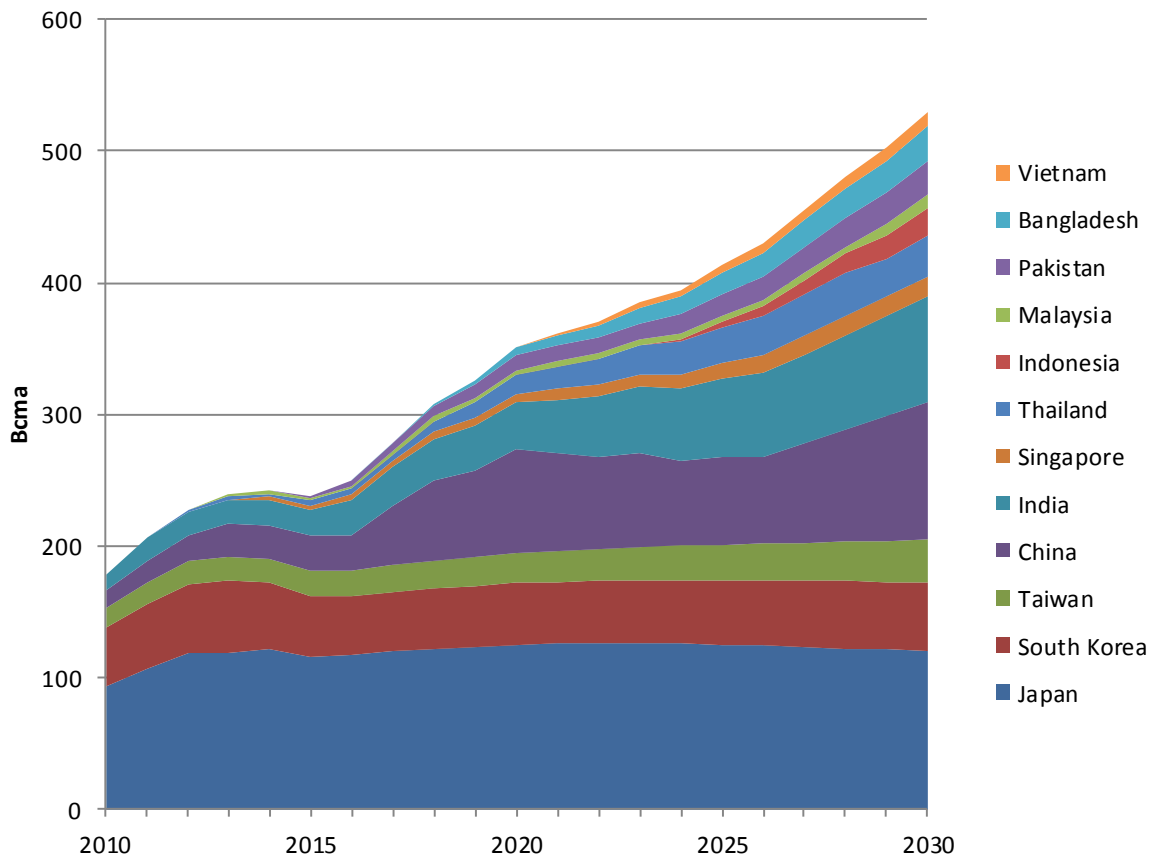
Figure 69: Asian LNG Imports 2010-2030 – Low Case



Source: Author's Analysis



Figure 70: Asian LNG Imports 2010-2030 – High Case

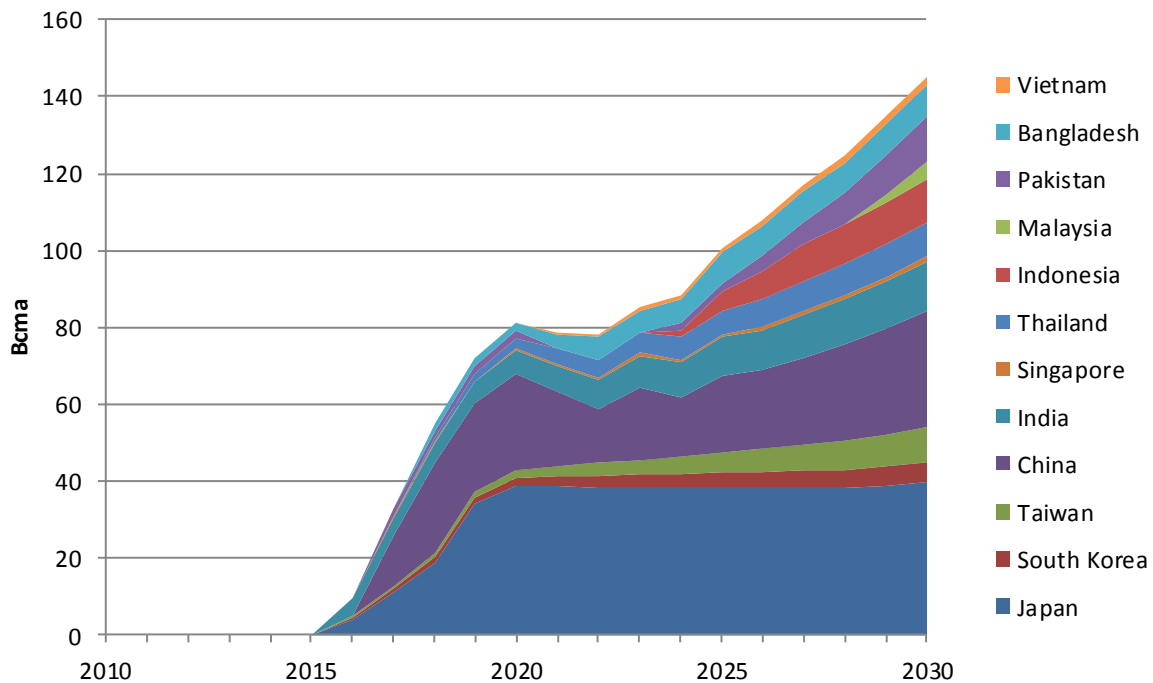


Source: Author's Analysis

In both the low and high cases the dominant markets, in terms of absolute volumes, are Japan, South Korea, China and India. By 2030 the total LNG import volumes from all countries considered here ranges from 385 to 530 bcm/y, compared with the 2015 total of 238 bcm/y. The annual average aggregate growth in LNG demand is 3.3% (low case) and 5.5% (high case). It is instructive to look at the country level variances between low and high cases – shown in Figure 71, as this highlights the key uncertainties for the period.



Figure 71: Asian LNG Imports 2010-2030 – Differences between Low and High Cases



Source: Author's Analysis

China and Japan dominate the picture between 2015 and the early 2020s. In the case of China the uncertainties relate to gas demand growth in the economic 'new normal' where government policy will be crucial in establishing a more material role for gas in the power sector (for CO₂ and particulate pollution abatement reasons) and in providing access infrastructure to enable growth in the residential and industrial sector. The future LNG requirement is also however subject to uncertainties in the gas supply mix; including conventional and unconventional domestic gas production, the scale of future pipeline imports from Turkmenistan and Central Asian and Russian pipeline gas from East and West Siberia. With Japan the main uncertainty is the pace and extent of the start-up of nuclear power plant, reducing the requirement for LNG imports and achieving long term energy efficiency goals.

In the case of Taiwan and South Korea, the scale of future LNG imports depends on uncertain economic growth prospects and energy mix policy. India poses a specific problem. The lack of a clearly defined role for gas in national energy policy, a 'muddled' regulated pricing policy and no clear plans for transmission system development make it difficult to project demand for gas and LNG in this potentially large market. With Thailand, Indonesia, Malaysia and Vietnam a major uncertainty is the future decline of domestic production as exploration prospectivity declines due to province maturity, often exacerbated by low regulated domestic pricing policies. While the future scope of LNG imports is difficult to ascertain this is likely to be an increasingly widespread dynamic and an important source of new global LNG demand in markets where natural gas already has a strong presence. The same issue applies to Pakistan and Bangladesh but with the added complication of delays to building import infrastructure due to poor investment frameworks, governance or end user credit-worthiness. This highlights an opportunity for future LNG supply projects, but it requires a markedly more pro-active marketing stance and credit-risk management capability than has traditionally been the case in the LNG business. The use of floating LNG regas units however is an added incentive to ensure that LNG supplied is paid for.

The high and low LNG import cases to 2025 are shown in Table 15.



Table 15: High and Low LNG Import Cases to 2030 (bcm/y)

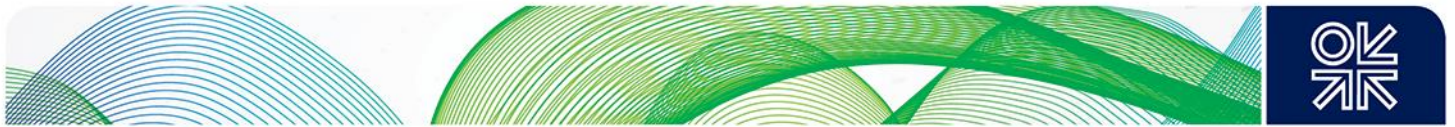
	Low Case					High Case				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Japan	96.4	115.7	86.0	86.5	80.6	96.4	115.7	124.6	124.7	120.3
South Korea	44.4	45.5	44.8	45.8	47.5	44.4	45.5	46.9	49.6	52.7
Taiwan	15.2	19.7	20.3	21.6	22.9	15.2	19.7	22.4	26.8	32.1
China	13.1	27.2	54.0	46.0	75.0	13.1	27.2	79.0	66.0	105.0
India	12.2	19.9	30.0	50.0	66.0	12.2	19.9	36.0	60.0	79.2
Singapore	-	2.8	6.6	10.7	13.8	-	2.8	6.9	11.4	14.9
Thailand	-	3.7	11.0	20.4	22.5	-	3.7	13.9	26.8	31.2
Indonesia	-	-	-	-	9.3	-	-	-	4.9	20.8
Malaysia	-	2.1	3.7	5.0	6.2	-	2.1	3.7	5.0	10.7
Pakistan	-	1.4	10.0	14.0	14.0	-	1.4	12.0	16.0	26.0
Bangladesh	-	-	4.0	8.0	18.0	-	-	6.0	16.0	26.0
Vietnam	-	-	-	4.4	9.1	-	-	-	5.7	11.4
Total	181.3	237.9	270.4	312.3	384.9	181.3	237.9	351.6	412.9	530.1

In summary the picture presented in this paper is one of LNG having to shed its mantle of a premium fuel whose import price is linked to that of oil and 're-market' itself as fuel which can contribute to a lower carbon future, by displacing coal in national energy mixes, and equally importantly reducing particulate emissions. This however calls for a radical renaissance in marketing by upstream LNG producers and strenuous efforts in cost reduction through competition in the liquefaction equipment sector.



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