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The expectation of an oversupplied gas market up to the mid-2020s has put natural gas demand back on the radar. This edition of the *Oxford Energy Forum* is dedicated to gas demand outlook in various regions of the world, with the starting point being the open question on whether, when, where and, eventually, at what price there will be sufficient demand to absorb the coming LNG wave.

In the first article, I explore the outlook for gas demand in the European market. After a sharp decline of about 100 billion cubic metres (bcm) in 2011–14, gas demand grew strongly in 2015 (+4 per cent) and in 2016 (+6 per cent). Despite stagnation in electricity demand and a continued increase in the penetration of renewables, the share of natural gas in the power generation mix rose. There were clear signs of some coal-to-gas switching taking place in several countries, but these trends were also boosted by colder temperatures and some special circumstances (hydro, nuclear, coal prices). Nonetheless, there are still several reasons to be carefully optimistic about gas demand in Europe in the next ten years or so – one of which being the potentially high number of firm power plants that could be closed down (potentially up to 100 GW). Even with only moderate power demand growth, this capacity will need to be replaced; these replacements will include gas-fired plants. However, one caveat must be borne in mind: natural gas is a fossil fuel and it will need to decarbonize (through the development of CCS or green gas) sooner rather than later if it is to keep a share in the energy mix, certainly post 2030 but most likely, even before.

In her article, *Gulmira Rzayeva* picks up on the uncertainties of gas-for-power demand, focusing on the Turkish gas market. Natural gas demand growth in Turkey was one of the fastest in the world and the fastest in Europe in the last two decades; however, since 2014 natural gas consumption in the country has started to decline month on month. The previous rapid demand growth meant that a shortage of gas might have occurred during the 2020s; as a result, the government decided to intervene in order to prevent such growth. It focused on lessening the share of gas in the power generation sector, the biggest gas consumer. The reduction of gas for power has significantly affected the overall natural gas demand growth in 2014 to 2016. Gulmira argues that this trend will continue, bringing the share of gas in the electricity generation sector down, while increasing the share of coal and renewables. The author expects that Turkish gas demand will be no more than 55–56 bcm/year by 2025 and 60–62 bcm/year by 2030.

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Searching for Natural Gas Demand in the Next Decade

Howard Rogers turns to what happens in countries on the other side of the world, namely Japan, Korean, and Taiwan. Although these markets tend to be grouped together (by Europeans) as the 'JKT' markets, their individual characteristics and drivers, in terms of natural gas/LNG consumption, vary considerably and, importantly, they also change over time. Howard argues that a faster-than-expected rise in renewables power generation in Japan, combined with indications of a slow but sustained nuclear re-start programme (in the context of stagnant total energy consumption) will effectively eliminate the outlook for LNG demand growth, absent a sustained shift away from coal. Conversely the new South Korean policy focus on constraining coal and nuclear appears to have genuinely improved the outlook for LNG demand growth for this country. Finally, Taiwan plans to close its nuclear plant by 2025. It is also favouring renewables and LNG at the expense of coal-fired generation.

In his second article, *Howard Rogers* covers the countries of south-east Asia which are significant gas markets and/or which engage in pipeline and LNG tradeflows. It is difficult to draw common conclusions for such a diverse group of counties, so Howard looks at two drivers which will determine their future LNG import requirements.

- The first is the likely/impending decline in existing domestic production or pipeline gas supplies. Countries where a decline in domestic production or pipeline gas supplies will likely lead to increased LNG imports by 2025 are: Singapore (pipeline supply), Indonesia, Thailand, Malaysia, Vietnam, and the Philippines.
- The second driver is uncertainty around the future energy mix and government policy. Howard concludes that Indonesia and Malaysia may be 'nudged' away from their apparent coal-focused path towards increasing their domestic gas consumption, which would hasten the point at which they would become net LNG importers.

Following on from that, *Sylvie Cornot-Gandolphe* explores the relationship between the non-power sectors and gas demand growth in non-OECD Asian countries. The region is the world's third-largest gas consuming region and the driver of global gas demand. One common driver in all countries is electricity growth, and hence rising gas demand by the power sector. However, the power sector is not expected to be the main driver of gas demand in coal-producing countries which have to import gas (China, India, Indonesia) as economic and security-of-supply issues will make it hard to substitute coal with gas. Sylvie argues instead that gas demand is now expected to come from the non-power sector – notably the industrial sector. In China, this is mainly due the replacement of coal in industrial applications, driven by the need to improve air quality. In other parts of emerging Asia, the increase mainly relies on industrialization policies and the strategic importance of some industries – such as fertilizers, petrochemicals, and steel – for the economy.

In her article, *Donna Peng* focuses on the trends in Chinese gas demand. Her starting point was to ask whether current signs of slowing gas consumption would be temporary or indicate a lasting trend. Donna argues that the unrevised 13th Five Year Plan target published in 2016 (360 bcm for 2020) is rather optimistic, representing a view that policy-pushed coal-to-gas conversion in the industrial sector will occur promptly. On the other hand, the long-term forecast (480 bcm for 2030) seems to be more realistic; even if demand for industrial non-energy use is expected to stagnate, demand in the residential and transport sectors is expected to continue to grow, and more coal-to-gas conversion in the industrial sector will have been completed within that time frame. Long-term demand for power generation, however, remains most uncertain, given significant oversupply and pending reform in the power sector.

Anupama Sen explores the short and long-term determinants of gas demand in India. Anupama points to the fact that no confident assessment of gas demand in India has been possible as its gas market as a whole has comprised two segments: one using gas allocated at regulated prices, and the other sourcing imported LNG at market prices. In addition, some degree of overlap between the two segments makes the picture even more complicated. Nonetheless, she provides an overview of three possible outcomes:

- one pointing to a continuation of the status quo to 2024, underpinned by sector-specific growth targets in which gas demand growth will continue to be driven by the underpinning policy targets in fertilizers, industry, and city gas;
- a second, where renewables targets are not met and there is potential for gas to fill the gap to 2027;
- a third in which coal is actively discouraged in the power sector, opening an important and immediate role for gas in the power sector to 2027 and beyond.

Anupama concludes that the most likely outlook is potentially some combination of the first (short-term) and second (medium-term) outlooks.

In her article, *Ieda Gomes* addresses the ongoing transformations of natural gas demand in the Middle East. Ieda argues that the region was, until recently, one the fastest-

growing gas markets in the world, driven by power, desalination, and energy-intensive industries. However, uncertainties related to geopolitics, a low-price investment-deterrent regulatory framework, and the threat of an increased share of nuclear and renewable energy may change the energy landscape significantly over the next five years, with a potential slowdown in gas demand.

Mustafa Ansari follows up on this and explores the challenges facing the Middle East and Northern African (MENA) region. Mustafa explains that because of capital constraints and uncertainties in the LNG market, many countries are opting for FSRUs as a temporary option – taking advantage of low prices before considering more expensive long-term options. He argues that in the longer term, higher domestic prices for gas (and power) will be required in order to incentivize the development of the region's gas resources. In addition, Mustafa points out that favourable market conditions should incentivize new MENA importers to do more to ensure they do not miss the opportunity to install import infrastructure and sign cheap and flexible LNG deals, but the impact on LNG imports (volume and timescale) is as yet largely uncertain.

In the following article, I look at the expectations around demand for natural gas and LNG in South America. The region turned to LNG in 2008 and LNG imports rose rapidly from 0.5 bcm in the first year to 17.2 bcm in 2015. However, in 2016, LNG imports only amounted to 11.6 bcm. This sudden downturn, although arguably not unexpected, cast a shadow of uncertainty over future LNG imports to the region, which was once viewed as a potential fast-growing market for LNG. Due to a combination of the normalization of hydropower generation in Brazil, economic slowdown, and rising indigenous production, annual LNG demand may not rise as previously expected. I explain that while LNG will remain important in South America to supply much-needed flexibility to meet seasonal needs or peak demand, the region is not expected to be a major future LNG market unless there are extreme climatic conditions, which will not happen every year and will not last for many years.

In his article, *Martin Lambert* explores the potential for new markets. Martin argues that to develop new markets for gas and LNG, many 'success factors' need to be in place at the same time, such as: suitable creditworthy demand (typically from power generation) and a supportive government policy framework. He expects, nonetheless, that as in the past, the vast majority of new growth in the gas industry will come from additional demand in countries which are already gas consumers, rather than from the creation of entirely new markets.

Following on from Martin's article, *Thierry Bros* addresses the particular case of the Ivory Coast and the role of FSRUs. Thierry points out that FSRUs and gas-fired power plants allow companies to test a market and to scale up if successful (or to leave it if unsuccessful). Nonetheless, private companies will need help from international agencies to kick start an FSRU project, as the cost of gas and the creditworthiness of African clients may complicate the development of such projects. And because expensive gas is not an option in Africa, the timing is also a real challenge. If a project starts this side of 2020, the new markets could benefit from low LNG prices as the market should remain long until the middle of the 2020s, but any delay may lose the opportunity to develop new markets for LNG in many countries of Africa.

Chris LeFevre then explores the demand for gas as a transport fuel. The level of interest for gas in transport is growing and scarcely a day goes by without an announcement of new investments in shipping or refuelling facilities, or the conclusion of a cooperation agreement between players in the market. Chris concludes that LNG as a marine fuel presents a viable alternative that has both financial and environmental advantages, but it is only likely to be adopted at the point of vessel renewal. On the other hand, developments in the maritime sector are likely to be key and this could provide a platform of significant scale to allow road-based usage to develop in a relatively risk-free environment.

Last but not least, in his article, *James Henderson* comes back to the relationship between coal and gas and explores what could be the key catalyst for coal-to-gas switching. While gas has consistently marketed itself as the 'clean' hydrocarbon, economic reality has continued to favour coal. Jim explores the differences in various regions (the USA, Europe, and Asia) and concludes that the factor making the strongest case for gas in many developing countries will be air pollution. Gas is more expensive than coal but it can provide a solution to a potential air quality crisis in many countries. The case for gas in developing countries is likely to be based on the willingness of governments and consumers to pay what will inevitably be a premium price for cleaner air quality.

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Natural gas demand in Europe

Anouk Honoré

In 2011–14, natural gas demand in Europe (unless otherwise stated, 'Europe' in these pages encompasses 31 countries: the EU (26 countries, as Malta and Cyprus did not consume gas in 2016) + Albania + Macedonia + Norway + Switzerland + Turkey) registered a sharp decline of about 100 billion cubic metres (bcm) (calculations from *Natural Gas Information 2016, IEA). All main sectors of consumption were affected, but the power sector – once the key driver for additional demand – registered the sharpest drop with about a 65 bcm loss. This drop could be explained by low power demand* resulting from difficult economic times and increased efficiency, rising renewable energies, and low coal and carbon prices which improved the competitiveness of coal versus gas in an already limited market (for additional details, see 'The outlook for natural gas demand in Europe', Anouk Honoré, OIES Paper NG 87, June 2014). However, after four years of steady decline, gas demand grew strongly in 2015 (+4 per cent) and in 2016 (+6 per cent). How long can this recovery be expected to last?

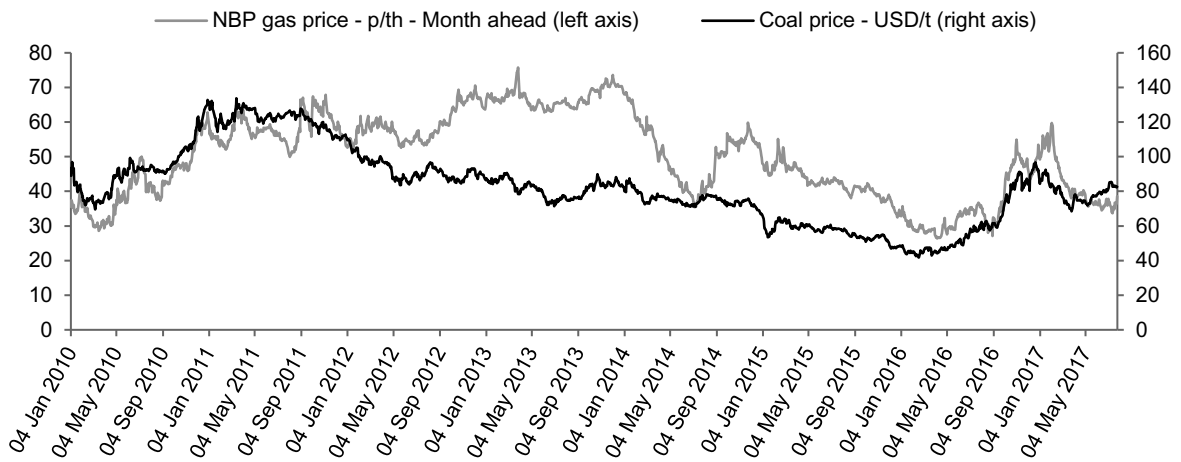
'GAS STARTED TO RECOVER SOME OF ITS SHARE IN THE ENERGY AND POWER GENERATION MIX IN 2015 AND THE TREND CONTINUED IN 2016.'

In a region where indigenous production covers only about half of the needs and is in sharp decline, gas demand changes are of tremendous importance. The following paragraphs focus on the main characteristics and trends of natural gas demand in the European region over the next five to ten years.

2015–16: short lived rebound?

Gas started to recover some of its share in the energy and power generation mix in 2015 and the trend continued in 2016. According to data from the International Energy Agency (IEA) and the Joint Organisations Data Initiative (JODI), natural gas demand reached 520 bcm in 2016. In absolute terms, the UK and Germany showcased the biggest growth, with nearly 10 and 8 bcm respectively, or about 60 per cent of total growth. Colder temperatures at the beginning of 2015 and in the final quarter of 2016 boosted gas demand for space heating but, more interestingly, gas consumption for power generation also started to increase again.

Despite a stagnation in electricity demand and a continued increase in the penetration of renewables, the share of natural gas in the power generation mix rose, especially in the second half of 2016. This happened mainly to the detriment of coal-fired power plants. From mid-2016, according to the Argus agency, coal prices started to rise (see the figure below) and in the last quarter of 2016, the c.i.f. ARA spot price averaged US$85.5/ton, the highest level since 2012 and a 68 per cent increase from the same period of 2015. The price increase was largely driven by market tightness in Asia, after China introduced measures restricting domestic coal output. Gas prices also started to increase in the fourth quarter of 2016, but higher electricity prices offset the increase in generation costs.



Coal and natural gas prices, London close, 2010–17

Source: Argus data.

Clean spark spreads remained positive in all major electricity markets, while at the same time, clean dark spreads remained low.

The change in coal/gas competitiveness was not the only explanation. Indeed, natural gas generation went up strongly at the end of the year, but so did coal generation, as other fuels did not fulfil their expectations. The second half of 2016 was drier than usual in many European countries and the share of hydro-based electricity generation declined. The share of nuclear was fairly stable, except at the end of the year when its share fell due to significant capacities being taken offline in western (and central) Europe, especially in France. This left some additional room for other fuels, including natural gas. Consequently, the past two years (2015–16) have witnessed some special circumstances (hydro, nuclear, the price of coal), which explain part of the rebound in gas demand in the power sector.

Can the UK example be replicated?

The UK introduced a carbon price floor in 2013, to complete the EU ETS price. In 2016, the carbon price floor was around £18 (about €21 per tonne). This national instrument provided an additional push and, combined with lower gas prices, the result was a dramatic decline of the coal share in the power generation mix in 2016 (see figure below). There were even some days without any coal in the mix, which had not happened since the 1880s.

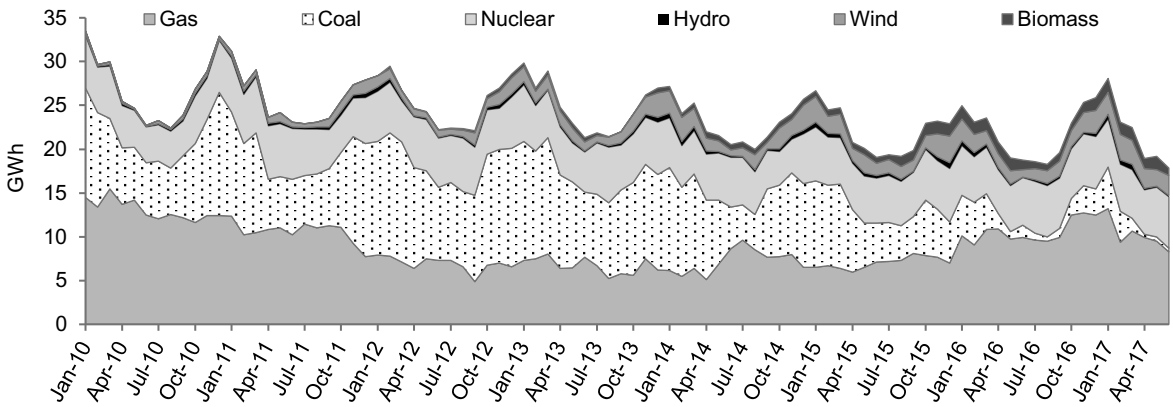
'THERE WERE EVEN SOME DAYS WITHOUT ANY COAL IN THE MIX, WHICH HAD NOT HAPPENED SINCE THE 1880s.'

Can the UK be used as an example for the rest of Europe? Yes, because it shows that simple switching from one existing coal plant to one existing gas plant can be done rapidly and has the additional benefit of producing less emissions. However, because of the wide diversity of the European gas markets, the results in other countries may not be as dramatic as those seen in the UK.

The UK (power and gas) market has many specificities that may not necessarily be shared by many other markets:

- There are/were large amounts of existing coal and gas capacity (especially electricity plants owned by utilities) and therefore switching/arbitrage from one to another was possible on a short-term basis.
- The existing coal plants were largely old and inefficient, which made them more uncompetitive than other existing newer plants in other markets.
- About 12 GW (of coal and oil plants) were shut down due to the Large Combustion Plant Directive, and closures continued in 2016.
- The UK market is still somewhat of an 'island' and interconnections with the rest of Europe are limited by interconnectors' capacity.
- Despite a rapid growth of renewables in the mix, the total share is still low, which made it easier to switch from coal to gas without too much interference from renewables availability.

There will not be a 'one size fits all' solution or 'one effective carbon price' across Europe. How much of a price is needed to make a difference in coal/gas competitiveness depends on various factors such as: plant efficiency, type of plants, power generation mix, and interconnections, to name but a few. For instance, in the case of highly efficient coal and gas plants (60 per cent efficiency for a CCGT and 45 per cent efficiency for a coal plant), a coal price of US$60/t, and a EU ETS carbon price of €5/t, gas plants theoretically become competitive at a gas price of about US$4/MMBtu. In the case of efficient gas plants and less efficient coal plants (60 per cent efficiency for a CCGT and 38 per cent efficiency for a coal plant),



British electricity generation, 2010–17

Source: Renewable Energy Foundation.

'THERE WILL NOT BE A "ONE SIZE FITS ALL" SOLUTION OR "ONE EFFECTIVE CARBON PRICE" ACROSS EUROPE.'

gas plants theoretically become competitive at a gas price of about US$6/MMBtu. Near-term carbon reduction can be achieved by greater utilization of existing gas generation which is either mothballed or running at low load factors at the expense of coal. This solution of a national carbon tax should therefore not be underestimated, but other factors will also come into play in the coming years.

Firm capacity closures expected by the mid-2020s

(Data in this section are estimates made by the author.) There is about 150 GW of coal capacity in Europe, out of which less than half have simply opted into the Industrial Emissions Directive (IED). Coal plants with a derogation represent about 82 GW (56 GW hard coal + 26 GW lignite). Coal plants in Transitional National Plans (TNPs) represent about 56 GW. These plants will need to be converted by 2020. In addition, about 19 GW have some sort of limited lifetime derogation (LLD). These plants can run for 17,500 hours and will need to be closed by 2023 (whichever comes first). Other derogations (district heating, local coal burn, accession treaty, isolated markets) represent about 7 GW. As a result, a majority of Europe's coal stations will require significant investment in the years to come, a large part of it before 2020, if they are to meet the IED's more stringent atmospheric pollution standards.

As further investment becomes necessary to remain operational (to comply with strengthened pollution standards and as policies to encourage decarbonization of electricity generation take effect) it is most likely that a large share of these plants will close in the near term. If national measures were taken (such as the carbon price floor in the UK), even for a limited time, this would probably give enough signals to owners of coal plants to close these down sooner rather than later. However, the impact will not be uniform across the EU. Out of 56 GW in TNPs, 16 GW alone are in the UK, about 11 GW in Poland, 8 GW in Spain, and more than 7 GW in the Czech Republic. Regarding the 19 GW in LLD, almost 8 GW are in Poland and 4 GW in the UK. One of the big variables is the precise timing of retirement of coal and lignite-fired capacity in some of those markets, as not all these plants can easily be closed in the next five years (and certainly not all can be replaced by switching to gas – Poland being the most striking example). However, there is the potential for up to 50 GW of coal plants to be shut down in the next five years or so in the EU due to impacts of the IED alone.

In addition, the EU agreed new emissions requirements on 28 April 2017. A new reference document (BREF) for the Best Available Technique (BAT) under the IED was decided; this introduced new emissions standards for local pollutants, including some (such as mercury) that had not been regulated so far in the power sector. Coal power plants in EU countries will have four years to adjust to these new standards, which are tighter than Emission Limit Values (ELVs) under the TNP compliance mechanism. These are very ambitious requirements (in both level of emissions and timing), and they should initiate the closure of many plants by 2021. Once implemented, these standards will help to favour gas plants over coal-fired ones in Europe, but there is already significant opposition in some key countries and the form of implementation in national laws is uncertain. Additional derogations seem to be likely, casting doubt on the exact date of closure, even if this would mean low operating hours and earlier retirement.

In addition, some currently existing plants – notably with firm capacity (as opposed to those with intermittent and unpredictable capacity, such as wind and solar) – could close down due to:

- rising costs involved in meeting higher national emissions values (for instance in Germany),
- political agreements (for instance the National Agreements in the Netherlands and the lignite-fired capacity reserve in Germany),
- commercial pressure due to low wholesale electricity prices (Germany),
- and/or just simply for having reached the end of their working life.

Some nuclear capacity is also going to be shut down. Germany has approved the phase-out of nuclear power by the end of 2022 and plans to close its remaining 11 GW by 2022. Declining profitability may also trigger additional closures, as seen in Sweden due to low wholesale electricity prices. Other countries (Spain, Belgium, or Switzerland for instance) had decided on an early phase out after Fukushima, but this position has been questioned and closing dates are uncertain.

It is difficult to estimate how much capacity will be retired due to political decisions, commercial reasons, or even old age, and each market will face its own dynamic, but it may be that as much as 100 GW of firm capacity could be shut down across Europe in the next five to ten years or so. Even with continued growth of renewable energies, it is likely that the gap between power demand and the amount that can be fulfilled by renewables will widen quickly (in the next five years), and at least until some

form of commercial battery storage develops. Even with only moderate power demand growth, this capacity will need to be replaced, including by gas-fired plants. There are about 2 GW of gas-fired plants under construction (1.5 GW in Poland plus some in Germany and also in Croatia). These are essentially CHPs. There are also about 30 GW of gas-fired capacity with full consent, which could in theory take final investment decision and start construction now if they got clear signals from politicians (or from the market). In addition, there are about 7 GW of coal-fired capacity under construction (4GW in Poland, 1GW in Germany, and some plants in Greece, Bosnia, and the Czech Republic) and about 4 GW of nuclear capacity under construction. Further developments of coal and nuclear projects are uncertain due to the decarbonization agenda of the European Union and difficulties in getting permits from national and regional authorities for new coal plants in western Europe, although there may be a different story in the smaller markets of central and eastern Europe.

'NATURAL GAS IS A FOSSIL FUEL AND IT WILL NEED TO DECARBONIZE … SOONER RATHER THAN LATER IF IT IS TO KEEP A SHARE IN THE ENERGY MIX …'

Conclusions

There are several reasons to be cautiously optimistic about gas demand in Europe in the next ten years or so. It will not get back to the strong growth seen in the 2000s, but in all likelihood it will stop declining and, under the right circumstances (especially in the power sector), it could also register some small growth. However, natural gas is a fossil fuel and it will need to decarbonize (by developing CCS or green gas) sooner rather than later if it is to keep a share in the energy mix, certainly post 2030, but most likely even before.

This author expects (on the basis of data from the IEA and national statistics) European conventional production to decline from 256 bcm in 2016 to about 212 bcm in 2020, and to about 146 bcm by 2030, a reduction of 110 bcm compared with 2016. Therefore, even in the case of flat demand, gas imports will be the key to fulfilling regional needs. Ample gas supplies are expected to be available thanks to:

- growing LNG exports from the USA and other regions, some of which will end up in Europe (for additional information, see 'Does the portfolio business model spell the end of long-term oil-indexed LNG contracts?', Howard Rogers, Energy Insight 10, OIES, April 2017), and from
- two Russian pipeline projects, TurkStream and Nord Stream 2, which are progressing despite opposition from central Europe.

As a result, on an annual basis, demand should easily be covered without any increase in price levels; however, with falling Groningen availability and Rough outage, there could still be some security problems and high price spikes in the event of high demand and prolonged cold weather, but this is another story.

Turkish natural gas demand decline

Gulmira Rzayeva

Natural gas is the main fuel in Turkey, accounting for almost 26 per cent of total primary energy supply in 2016. In the last two decades, natural gas demand growth in Turkey has been among the fastest in the world, and was the fastest in Europe – rising from 15 bcm (billion cubic metres) in 2000 to 48.8 bcm in 2015 according to EMRA (Energy Market Regulation Authority) – mainly as a result of economic growth. The rapid demand growth continued until May 2014, when natural gas consumption in the country started declining month on month. This occurred as a result of government intervention aimed at lessening the share of gas in the energy mix in the power generation sector, the biggest gas consumer segment of the economy. Before the government introduced a support scheme for renewable energy, the rapid growth in natural gas demand would have led to a shortage of gas during the 2020s. At that point, not only are the long-term contracts between BOTAŞ (Turkey's state-owned oil and gas pipeline and trading company) and all its suppliers of pipeline gas due to expire (Azerbaijan in 2021, Iran in 2026, and Russia in 2021), but also the contracts

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of private companies with Gazprom are due to end in 2021, affecting around 36 bcma (bcm per year) of gas for all contracted gas. Any possible shortage of gas in the country could not only put energy security at risk, but also affect the internal political situation. Natural gas production is negligible – 0.4 bcma – making Turkey almost entirely

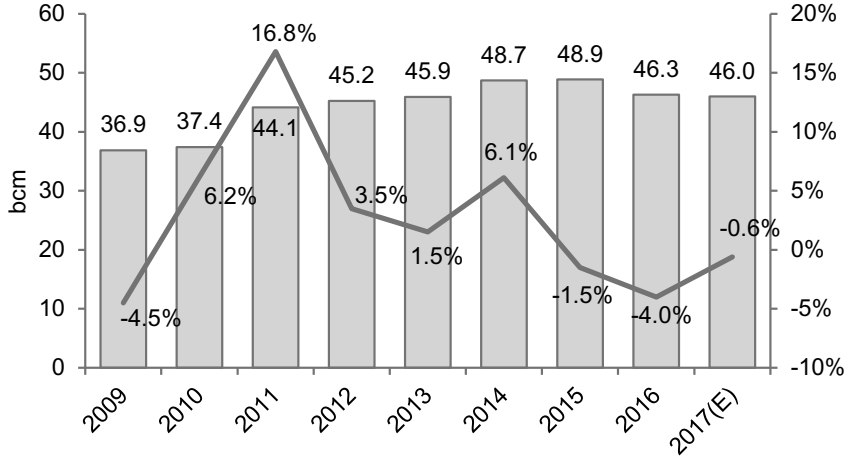
dependent (98 per cent) on external suppliers. This creates an increasing energy import bill (which constitutes around 60 per cent of the country's foreign trade deficit) represented by a cost of US$50 billion/year on energy and mineral imports in 2016, according to the country's Ministry of Energy and Natural Resources.

Government efforts to reduce Turkey's dependence on energy imports

With this concern in mind, the government of Turkey initiated a policy of reducing the share of imported gas and increasing the share of domestically produced energy resources (mainly hydropower, coal, lignite, wind, and solar energy) in the energy mix, particularly in the power generation sector. The government introduced a number of strategies and action plans on energy efficiency and renewable energy. For instance, it initiated an *Electricity Market and Security of Supply Strategy* in 2009, and in its *Vision 2023* (the year that marks the 100th anniversary of the Republic of Turkey) published in 2010, the government adopted targets to fully utilize the lignite and hard coal potential of the country by 2023. Overall, the *Vision* foresees increasing the share of renewable sources in the electricity mix to 30 per cent, of coal to 30 per cent, and of nuclear plants to 10 per cent, while reducing the share of natural gas to 30 per cent. The government has already almost succeeded in achieving its targets and, according to EMRA, has managed to reduce the *share of gas in the power generation sector* as follows:

- 48.12 per cent (or 23.5 bcm) in 2014;
- 37.9 per cent (16.52 bcm) in 2015;
- 33 per cent (15.7 bcm) in 2016.

The first results of *Vision 2023* became apparent as early as May 2014, when natural gas demand in Turkey started



Gas consumption: demand growth changes, 2009–17
Source: EMRA.

declining almost every month by an average of around 6 per cent, with an overall decline in 2016 of 4 per cent from 2015 (see figure above).

The government achieved a remarkable outcome in 2016 (a record year) with around 49 per cent of Turkey's electricity generation coming from domestic and renewable resources, of which 7.8 per cent came from renewables alone, according to TEIAŞ, the Turkish Electricity Transmission Corporation. The share of domestic coal in electricity generation rose from 12 to 16 per cent. To achieve this, the government implemented new regulations, provided a number of incentives to the private sector to attract investment in renewable energy and local coal-fired plants, and introduced feed-in tariffs that were supportive of the private sector.

Thus, a number of major factors have played significant roles in the decline in the demand for gas over the last three years and will result in further sluggish growth in the next few years. In addition to the new political focus on non-gas fuels in the power sectors, those factors are:

(a) concerns related to increasingly high dependence on natural gas imports and the issue of supply security;

(b) the balance of payment deficit caused by the significant difference between the cost of energy imports and the heavily subsidized price charged by BOTAŞ to domestic customers;

(c) GDP decline due to political instability in the country over the last two to three years.

Moreover, there are technical issues that constrain both BOTAŞ and private gas import companies from importing greater volumes of gas, or even from offtaking the full contracted volumes. Such technical constraints limit the penetration of additional volumes of gas into the BOTAŞ gas transmission system, as entry and transfer capacity limitations put a strain on the system, especially during high demand periods. These factors also contributed indirectly to the demand decline.

Natural gas demand decline in power generation sector

The power generation sector is the biggest consumer of gas in Turkey (33 per cent share in 2016). Any changes in gas supply and consumption in this sector have a

'GAS COMBUSTION FOR POWER FELL CONSIDERABLY IN 2015 AND MOST OF 2016, DUE TO INCREASED RENEWABLE AND COAL-FIRED INSTALLED CAPACITY AND OUTPUT.'

tangible effect on overall national demand growth. The new Electricity Market Law (No. 6446), introduced in 2013, successfully implemented liberalization of the energy market. As a result, most power generation assets (excluding hydro and some coal assets) as well as the distribution sector, have been privatized. Liberalization of the electricity market and privatization of the sector have contributed to an increase in the production of electricity from local resources, which in turn has increased the total amount of power production, and indirectly affected electricity demand. Privatization attracted greater investment into the sector and boosted capacity margins. Gas combustion for power fell considerably in 2015 and throughout most of 2016, due to increased renewable and coal-fired installed capacity and output.

The share of *renewable energy* (solar and wind only) in the power generation sector has increased over the last few years as follows:

- 3.4 per cent in 2014 (consisting of 8,520.1 GWh for wind and 17.4 GWh for solar);
- 5 per cent in 2015 (11,652.5 GWh for wind and 194.1 GWh for solar);
- 7.8 per cent in 2016.

This represents a total increase in wind's contribution to power generation of 36.8 per cent and in solar's of 1015.3 per cent in the period 2014–2015. The production of electricity from renewables exceeded the set target by a factor of three, reaching a total of 15.083 GWh instead of the targeted 5.423 GWh in 2016.

In May 2016 the Ministry of Energy and Natural Resources (MENR) issued the Regulation on Renewable Energy Resources; this set out the terms and conditions of the government's support scheme to renewable energy producers aimed at attracting more investment and increasing the share of solar and wind energy in the electricity generation energy mix. The Regulation includes:

- tax incentives for wind and solar energy (including both tax refunds and exemptions);
- de-licensing companies producing no more than 5 MWh of renewable energy;
- a minimum ten year government purchase guarantee for electricity produced by wind, solar, hydroelectric, geothermal, and biomass.

The share of both imported and domestically produced coal and lignite has risen significantly in the energy mix over the last two to three years. The share of coal in the power generation sector has changed:

- 30.3 per cent in 2014;
- 29.1 per cent in 2015;
- 33 per cent in 2016.

Higher coal-fired power generation and renewable output in Turkey led to a more balanced generation mix in 2016, with gas burn for power continuing its year-on-year decline. Coal-fired generation rose by 22 per cent year-on-year in 2016, pressing gas-fired output to fall by 9 per cent, according to TEIAŞ.

Little to no change, or a slight decline, is expected in gas demand growth in the power generation sector in 2017.

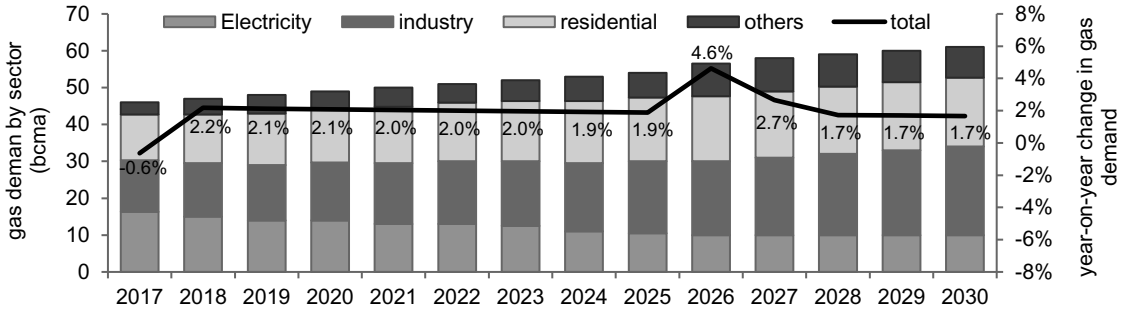
'LITTLE TO NO CHANGE, OR A SLIGHT DECLINE, IS EXPECTED IN GAS DEMAND GROWTH IN THE POWER GENERATION SECTOR IN 2017.'

It is most likely that the demand growth will be flat to slightly higher during the 2020s, and show modest growth in a longer-term perspective if imported gas prices remain favourable for Turkey, as electricity demand growth will accelerate. The share of gas in the energy mix in this sector may, however, decrease further as a result of government measures and support schemes for other than gas-fired power generation, depending on the pace of renewable energy deployment, coal development, and electricity demand growth. Gas will continue to lose out to coal in competition in the wholesale market, thanks to the government support scheme which gives coal an advantage over gas use in power generation, in the absence of a carbon levy or new environmental restrictions.

Conclusions

Over-optimistic projections made by BOTAŞ in 2012 were based on calculations of electricity demand, population, Gross Domestic Product (GDP), and Foreign Direct Investment (FDI) growth which had proved accurate in 2013 and 2014. However, on the basis of these projections, the government decided to take solid measures to prevent such a growth in demand – which might have more than doubled by 2030 without intervention, and would also have affected Turkey's economic and political security.

The Turkish government initiated programmes and action plans to lessen the share of gas in the electricity generation energy mix, the biggest gas consuming sector. The measures undertaken were effective in just a few years and resulted in an almost 27 per cent reduction in the share of gas in this sector (from 60 per cent in 2007 to 33 per cent in 2016). As a result, overall gas demand declined from 48.8 bcm in 2015 to 46 bcm in 2016, the first decline since 2009.



Turkey's gas demand growth projection, 2017–30

Source: Author's estimates.

The reduction in natural gas demand in the power generation sector has significantly affected overall natural gas demand growth in the period 2014 to 2016. This trend will continue, bringing the share of gas in the electricity generation sector down, while increasing the share of coal and renewables. Given the government's decisiveness, the target of a 30 per cent gas share in the power sector by 2023 (33 per cent in 2016 or 16 bcm) is most likely to be achieved in one to two years, and it seems that the government will continue this policy in the longer term. However, this policy is not directed at the residential and industrial sectors, where demand growth has been quite modest. On the contrary, BOTAŞ is prioritizing gas usage in the residential sector and during the seasonal peak demand periods it diverts additional volumes from the power sector to households. Given an average growth of 1 bcma of gas in the short and mid-run and little to no growth in the long-run, it is expected that demand in this sector will be no more than 17.5 bcma by 2025 and 18.5 bcma by 2030. Likewise, industrial sector demand growth will be no more than 1 bcma until 2030, but this will largely depend on the growth of GDP and FDI, especially in the most gas-intense spheres such as production and manufacturing (chemical and petrochemical products production, textile, leather, and clothing manufacture, transport vehicle production, organized industrial zones). As a result, the fall in natural gas consumption in the power sector will be balanced by moderate growth in the residential and industrial sectors in 2017, and given the calculations above, analyses from a paper by the author 'Turkey's gas demand decline: reasons and consequences' (Gulmira Rzayeva, OIES Energy Insight, April 2017) show that Turkey's gas demand will be no more than 55–56 bcma by 2025 and 60–62 bcma by 2030 (see figure above).

Japan, South Korea, and Taiwan

Howard Rogers

Japan

The consequences of the 2011 Fukushima disaster, which boosted Japan's coal, oil, and gas consumption to compensate for the loss of nuclear generation, together with the impact of many years of modest GDP growth, still influence Japan's energy position. Primary energy consumption in 2016 was unchanged on 2015 and 10.2 per cent below that of 2010. Japan's overriding objective is the progressive re-start of its operable nuclear reactors once these have passed the Nuclear Regulatory Authority's safety assessment and completed any required upgrading. The additional hurdle of achieving local government consent and overcoming related legal actions brought by dissenting lobby groups has also been a feature of the re-start process, slowing the pace considerably. In May 2017, the Takahama 4 reactor resumed power generation, becoming only the fourth reactor to achieve operational status (the others being Sendai 1 and 2 and Ikata 3). The Takahama 3 reactor was expected to re-start in July 2017 and in early June an appeal was overturned, allowing the Genkai 3 and 4 reactors to re-start in due course. Of the other 36 potentially operable reactors, 17 have applied to re-start to date. The pace and extent of the re-start process has resulted in coal, oil products, and gas

'OVERWHELMINGLY [JAPAN] RELIES ON LNG FOR ITS GAS REQUIREMENTS AND HAS BEEN THE WORLD'S LARGEST LNG IMPORTER SINCE THE 1970s.'

consumption remaining at higher levels than just prior to Fukushima (in 2016 coal, oil, and gas comprised 26.9, 41.4, and 22.5 per cent of the total energy mix, compared with 23.3, 40.9, and 17.1 per cent in 2010).

Japan has very minor, approximately 3 bcma (billion cubic metres per year), levels of domestic gas production and produces around 1 bcma of synthetic gas from oil feedstock. Overwhelmingly it relies on LNG for its gas requirements and has been the world's largest LNG importer since the 1970s. After recovering from aftermath of the financial crisis, LNG imports reached some 93 bcma in 2010 before ramping up to around 117 bcma in the 2012 to 2014 period, in the aftermath of Fukushima. LNG imports fell back to 112 and 110 in 2015 and 2016 respectively. Japan's key gas consumption sectors are power generation and industry. From FY2011 to FY 2015, Japanese power generation has fallen by 2.4 per cent per year, allegedly due to energy efficiency measures, but also as a consequence of low economic growth and a declining population.

The table below shows Japanese primary energy consumption by fuel/technology for 2010 to 2016. In the period 2014 to 2016 gas consumption was squeezed by increases in renewables (especially solar) and a modest level of nuclear re-start. Coal consumption held steady.

Of note however, is the year-to-date increase (January–May 2017) for LNG imports, which is 10 per cent up on 2016. Commentators attribute this to colder than normal weather in early 2017; however, stronger manufacturing output may be also responsible for part of this.

Government policy aims for a *2030 power generation mix* comprising:

- nuclear at 20–22 per cent,
- renewables at 22–24 per cent,
- LNG at 27 per cent,
- coal at 26 per cent.

[This compares with the 2015 position of: 0.9 per cent nuclear, 17 per cent renewables (including hydro), 39 per cent LNG, and 34 per cent coal.] The policy aims to reduce CO_2 emissions by 21.9 per cent from the 2013 level and to improve energy self-sufficiency from 6.3 per cent in 2012 to 24.3 per cent. By 2030, economic growth would normally be assumed to have led to an increased energy demand of 411.3 billion litres (oil equivalent) from the 2013 figure of 361 billion litres (oil equivalent). Efficiency measures are assumed to reduce this to 326 billion litres (oil equivalent) by 2030. Achieving these goals will be challenging, as they assume a similar path to that which was achieved in the period 1970–90 and Japan is already regarded as the sixth most energy efficient nation.

In summary, the outlook for gas (and hence LNG) demand in the coming decade is one of at best stagnation and more likely decline. Absent a significant growth in gas consumption in the industrial sector, the upside for gas demand lies in a greater displacement of coal than policy requires (coal's share of primary energy consumption, at 26.9 per cent in 2016, is in line with the 2030 goal) or a policy 'U turn' which halts the nuclear re-start programme. Japan suffers from high fine particulate matter (PM2.5) emissions, although this appears to be blamed on sources in China. It is possible that air quality concerns might support a shift from coal to gas in Japan – although on the downside, nuclear re-start and the growth of renewables can only reduce gas demand, the question being pace and extent. Whether the government achieves its ambitious energy efficiency goals is a moot point, but significant primary energy consumption growth,

Japan primary energy consumption, 2010–16 (million tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	85.1	95.0	105.2	105.2	106.2	102.1	100.1
Oil	202.7	203.7	217.7	207.4	197.0	189.0	184.3
Coal	115.7	109.6	115.8	121.2	119.1	119.9	119.9
Nuclear	66.2	36.9	4.1	3.3	0.0	1.0	4.0
Hydro	19.7	18.3	17.2	17.7	18.1	19.0	18.1
Solar	0.9	1.2	1.7	2.9	5.3	8.3	11.2
Wind	0.9	1.0	1.1	1.2	1.1	1.2	1.6
Geothermal, biomass and other renewables	4.9	4.8	5.0	5.2	5.3	5.3	6.0
Total	**496.0**	**470.4**	**467.7**	**464.0**	**452.3**	**445.8**	**445.3**

Source: BP Statistical Review of World Energy 2017.

as a 'rising tide which floats all boats' (including gas) can be discounted as unlikely. Due to a colder first half of 2017, Japanese LNG imports may amount to 115 bcma in 2017. A 'High Case' could see LNG imports declining to 106 bcma by 2020 and to 101 bcma by 2025. A 'Low Case' might see 103 bcma by 2020 and 93 by 2025. It is worth noting that the 2030 level of LNG imports (consistent with government policy) is just above 80 bcma.

South Korea

The country has enjoyed consistently robust GDP growth (in excess of 2 per cent per year) in recent years, based largely on manufacturing and technology product exports. As might be expected, this has resulted in continuous annual primary energy growth (apart from just a minor increase of 0.4 per cent year-on-year in the post-global financial crisis year of 2009). Annual average primary energy consumption growth from 2010 to 2016 was 1.9 per cent. South Korea's domestic gas production peaked at 0.6 bcma in 2010 and has since declined.

The rebound in South Korea's LNG demand in 2010 (after Asia's post-global financial crisis LNG demand drop in 2009) was represented by an increase of 10 bcma over 2009

'[SOUTH KOREA] HAS ENJOYED CONSISTENTLY ROBUST GDP GROWTH … IN RECENT YEARS, BASED LARGELY ON MANUFACTURING AND TECHNOLOGY PRODUCT EXPORTS.'

(greater than that of Japan at 8.3 bcma). From a figure of 43.1 bcma in 2010, annual South Korean LNG demand rose to 53.9 bcma by 2013 before, somewhat surprisingly, declining to 44.4 bcma in 2015. There was a modest increase of 2 per cent, to 45.2 bcma, in 2016. Consistent with reports of colder than normal weather in first half 2017, South Korea's year-to-date LNG imports to May 2017 were 8.4 per cent up on 2016.

The table below shows the interaction between fuel sources/technologies making up South Korea's primary energy mix between 2010 and 2016. While renewables have increased from past levels, they still represent an immaterial share of the primary energy mix. Nuclear generation declined by 7.7 per cent in 2013 but then recovered to reach higher levels in 2014–16 (12.8 per cent of TPES) than those seen in 2010. Coal surged in 2014 and 2015 but then fell in 2016 (28.5 per cent). Gas (LNG) bore the brunt of these nuclear and coal usage fluctuations (14 per cent in 2016).

The main candidates for the June 2017 Presidential election all espoused a move away from coal (on the grounds of pollution) and nuclear (on the grounds of safety) in favour of renewables and natural gas. This would include shelving plans to construct new coal and nuclear power generation plant. Such policies, if enacted, would provide a significant upside for LNG demand in South Korea. In terms of future growth, a 'High Case' could see LNG imports increasing to 52.4 bcma by 2020 and to 61.3 bcma by 2025. A 'Low Case' might be 49.3 bcma by 2020 and 51.8 bcma by 2025.

Taiwan

Economic growth in Taiwan slowed in 2015, but appears to have subsequently recovered. As shown in the table overleaf, Taiwan's primary energy consumption has plateaued for the past three years, although the consumption of gas (all LNG apart from 0.3 bcma of domestic production) has grown at an annual average rate of 5.3 per cent since 2013, at the expense of coal and nuclear. In 2016 Taiwan's LNG imports were 20.1 bcma, up from 19.3 bcma in 2015, and 17.9 bcma in 2014. In 2017 the May year-to-date LNG import total was up 12.5 per cent on 2016.

South Korea primary energy consumption, 2010–16 (millions tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	38.7	41.7	45.2	47.3	43.0	39.3	40.9
Oil	105.0	105.8	108.8	108.3	107.9	113.8	122.1
Coal	75.9	83.6	81.0	81.9	84.6	85.5	81.6
Nuclear	33.6	35.0	34.0	31.4	35.4	37.3	36.7
Hydro	0.8	1.0	0.9	1.0	0.6	0.5	0.6
Solar	0.2	0.2	0.2	0.4	0.6	0.9	1.2
Wind	0.2	0.2	0.2	0.3	0.3	0.3	0.4
Geothermal, biomass and other renewables	0.7	1.3	1.5	1.7	2.5	2.7	2.7
Total	**255.0**	**268.9**	**271.8**	**272.2**	**274.9**	**280.2**	**286.2**

Source: BP Statistical Review of World Energy 2017.

Taiwan primary energy consumption, 2010–16 (millions tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	12.7	14.0	14.7	14.7	15.5	16.5	17.2
Oil	47.2	44.5	44.6	45.1	46.1	46.5	46.7
Coal	37.6	38.9	38.0	38.6	39.0	37.8	38.6
Nuclear	9.4	9.5	9.1	9.4	9.6	8.3	7.2
Hydro	0.9	0.9	1.3	1.2	1.0	1.0	1.5
Solar	0.0	0.0	0.0	0.1	0.1	0.2	0.3
Wind	0.2	0.3	0.3	0.4	0.3	0.3	0.3
Geothermal, biomass and other renewables	0.5	0.4	0.4	0.4	0.5	0.5	0.5
Total	**108.6**	**108.7**	**108.4**	**109.9**	**112.1**	**111.1**	**112.1**

Source: BP Statistical Review of World Energy 2017.

Taiwan appears to be holding to its plan to shut down all its nuclear power plants by 2025 and is also favouring renewables and LNG at the expense of coal-fired generation. Plans to increase renewables by 580 per cent and increase LNG import capacity to 39 bcma by 2025 are ambitious, but nevertheless illustrate the level of determination by policy makers to change the energy mix.

In terms of future growth, recognizing the 'aspirational' extent of current policy, a realistic 'High Case' could see LNG imports increasing to 27 bcma by 2020 and to 33 bcma by 2025. A 'Low Case' (Business as Usual) might be 23 bcma by 2020 and 25 bcma by 2025.

'TAIWAN [PLANS] TO SHUT DOWN ALL ITS NUCLEAR POWER PLANTS BY 2025 AND IS ALSO FAVOURING RENEWABLES AND LNG AT THE EXPENSE OF COAL-FIRED GENERATION.'

Conclusions for Japan, South Korea, and Taiwan

Although these markets tend to be grouped together (by Europeans) as the 'JKT' markets, their individual characteristics and drivers in terms of natural gas/LNG consumption vary considerably and, importantly, these change through time. Since the previous extensive review of these markets by OIES in 2015 (undertaken for the book *LNG Markets in Transition: the great reconfiguration*, edited by Anne-Sophie Corbeau and David Ledesma, OIES and KAPSARC, 2016) the following changes are of note:

- Japan has seen a faster than expected rise in renewables power generation which, combined with indications of a slow but sustained nuclear re-start programme (in the context of stagnant total energy consumption), effectively eliminates the outlook for LNG demand growth, absent a sustained shift away from coal.
- South Korea's GDP growth appears more robust and is reflected in its most recent primary energy consumption growth. The new policy focus on constraining coal and nuclear appears to have also genuinely improved the outlook for LNG demand growth.
- Taiwan's plans to close its nuclear plant by 2025 appear to have sustained support; however, the degree to which this is possible through renewables growth and LNG (while ramping down coal consumption) is at present untested.

South-east Asia

Howard Rogers

This section covers those countries of south-east Asia which are significant gas markets and/or which engage in pipeline and LNG tradeflows. Given their distinct characteristics, each is addressed individually and broad conclusions reached. More information can be found in the book *LNG Markets in Transition: the great reconfiguration*, edited by Anne-Sophie Corbeau and David Ledesma, OIES and KAPSARC, 2016.

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, the world's

Indonesia primary energy consumption, 2010–16 (million tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	39.1	37.9	38.0	36.7	36.8	36.4	33.9
Oil	64.7	73.1	74.4	74.5	75.3	71.8	72.6
Coal	39.5	46.9	53.0	57.0	45.1	51.2	62.7
Hydro	3.9	2.8	2.9	3.8	3.4	3.1	3.3
Renewables	2.1	2.2	2.2	2.2	2.3	2.4	2.5
Total	**149.3**	**162.8**	**170.5**	**174.2**	**162.9**	**164.8**	**175.0**

Source: BP Statistical Review of World Energy 2017.

third-largest coal producer, was one of the earliest LNG exporters. Indonesia has enjoyed consistently high GDP growth (average 2000–14: 5.3 per cent), with positive growth maintained through the 2008/9 global financial crisis period. GDP contracted in late 2016, but is expected by the World Bank to be 5.2 per cent for 2017.

'SINCE 2012 INDONESIA HAS DIVERTED INCREASING VOLUMES OF LNG … TO ITS DOMESTIC MARKETS.'

While primary energy consumption increased on average by 2.7 per cent per year between 2010 and 2016, gas consumption fell by 2.3 per cent per year – largely due to the increase in coal, whose 2016 consumption was 60 per cent higher than in 2010 (see Indonesia table above). Domestic gas demand is dominated by industry (which has been stagnant since 2012) and power generation. Gas consumption in power reached a peak in 2014 and has since declined. Gas production has been in decline since 2010, although against this backdrop of province maturity, individual projects such as Tangguh phase 3 may moderate the trend. Since 2012 Indonesia has diverted increasing volumes of LNG (in 2016 16 per cent of its total) to its domestic markets. The outlook for gas demand is for a continued gentle decline (absent a change in domestic policy favouring gas at the expense of coal in power generation). Pipeline exports to Singapore are expected to reduce but this notwithstanding, longer-term gas production decline and continued (and growing) diversion of LNG output to its own domestic market may result in Indonesia becoming a net LNG importer between 2025 and 2030. It is possible that either internal or external challenges may change the trajectory of coal consumption, though whether this is to the benefit of gas, or a belated policy support for renewables, is uncertain.

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). Malaysia has a diversified economy and has become a leading exporter of electrical appliances, electronic parts and components, palm oil, and natural gas. After the Asian financial crisis of 1997/8, Malaysia continued to post solid growth rates, averaging 5.5 per cent per year from 2000 to 2008. Malaysia was hit by the global financial crisis in 2009 but recovered rapidly, posting growth rates averaging 5.7 per cent since 2010.

Malaysia's primary energy consumption is still growing strongly (see Malaysia table below). Gas demand in 2016 was up 3 per cent on 2015. Gas demand is dominated by the power generation sector (around 50 per cent), in which it is government policy to meet incremental demand from coal, from renewables (to a very minor extent), and to allow the share of gas to slowly decline. This suggests that gas demand may plateau at around 47 bcma by 2020. Although production

Malaysia primary energy consumption, 2010–16 (million tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	26.6	31.3	31.9	36.3	38.0	37.6	38.7
Oil	29.3	31.5	32.9	34.9	34.9	35.5	36.3
Coal	14.8	14.8	15.9	15.1	15.4	16.9	19.9
Hydro and renewables	1.7	2.2	2.4	2.9	3.3	3.8	4.5
Total	**72.4**	**79.8**	**83.2**	**89.2**	**91.5**	**93.8**	**99.5**

Source: BP Statistical Review of World Energy 2017.

Singapore primary energy consumption, 2010–16 (million tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	7.9	7.9	8.5	9.5	9.8	11.0	11.3
Oil	60.9	63.7	63.4	64.2	65.8	69.4	72.2
Coal	0.0	0.0	0.0	0.3	0.4	0.4	0.4
Renewables	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Total	**69.0**	**71.7**	**72.0**	**74.1**	**76.2**	**81.0**	**84.1**

Source: BP Statistical Review of World Energy 2017.

has been growing in recent years, in a mature province there is a possibility that this may reach a plateau and decline in the early 2020s. Malaysia imports gas (pipeline) from offshore fields in Indonesia, the Malaysia–Thailand Joint Development Area, and the Malaysia–Vietnam Commercial Arrangement Area. In 2016 such volumes totalled 2.6 bcma, set against 1.7 bcma of pipeline exports from Malaysia to Singapore. Malaysia exports 33 bcma of LNG and imports 2 bcma at present. The prospect of a decline in domestic production would erode Malaysia's LNG export surplus in the 2020s, even with stagnating domestic gas consumption.

Singapore

Although Singapore has historically enjoyed consistently high rates of GDP growth, expectations have been reduced of late, following a slow-down in manufacturing output growth. Nevertheless, its first quarter 2017 GDP growth of 2.5 per cent year-on-year is considered robust.

'SINGAPORE'S FAST-GROWING PRIMARY ENERGY CONSUMPTION IS DOMINATED BY OIL PRODUCTS IN TRANSPORTATION.'

Singapore's fast-growing primary energy consumption is dominated by oil products in transportation (see Singapore table above). Gas prevails in the stationary sector, with minor contributions from coal and renewables, but gas demand is overwhelmingly from power generation. At present, Singapore imports pipeline gas from Indonesia and Malaysia, although these are expected to decline and terminate by 2025. In 2016 LNG met just 22 per cent of the country's gas requirements of 12.5 bcma. By 2025, gas consumption could reach 16 bcma, with LNG meeting most if not all of its requirement in that year.

Thailand

Thailand has moved from a low to an upper-income country in less than a generation. The global financial crisis cut exports, and in late 2011 Thailand's recovery was interrupted by severe flooding in the industrial areas of Bangkok and surrounding provinces. Long-term economic aspirations are laid out in Thailand's recent 20-year strategic plan for attaining developed-country status through broad reforms. Reversing the relative erosion of competitiveness, improving public sector effectiveness, and improving education and skills will be particularly important in moving Thailand from middle to high-income status.

The growth in Thailand's primary energy consumption has slowed in recent years, with gas demand falling back slightly in 2016 compared to 2015. Oil has gained since 2014 but coal has stagnated, and while renewables have grown from a low base they still represent less than 3 per cent of energy consumption (see Thailand table below).

While Thailand's gas consumption may continue to grow modestly (reaching perhaps 55 bcma by 2025) its domestic

Thailand primary energy consumption, 2010–16 (million tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	37.2	38.1	41.8	42.0	42.9	43.8	43.5
Oil	47.7	49.7	52.3	54.5	55.0	57.3	59.0
Coal	15.5	15.8	16.5	16.3	17.9	17.6	17.7
Hydro	1.2	1.8	1.9	1.2	1.2	0.9	0.8
Renewables	0.8	0.9	1.2	1.6	2.0	2.3	2.8
Total	**102.4**	**106.4**	**113.7**	**115.7**	**119.1**	**121.8**	**123.8**

Source: BP Statistical Review of World Energy 2017.

Vietnam primary energy consumption, 2010–16 (million tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	8.5	7.6	8.4	8.8	9.2	9.6	9.6
Oil	15.6	16.9	17.1	17.3	18.0	18.8	20.1
Coal	14.0	16.5	15.0	15.8	18.9	22.3	21.3
Hydro and renewables	6.2	9.3	11.9	12.9	13.6	12.9	13.8
Total	**44.3**	**50.3**	**52.5**	**54.8**	**59.8**	**63.7**	**64.8**

Source: BP Statistical Review of World Energy 2017.

production peaked in 2014 (41.6 bcma) and by 2016 had declined to 38.6 bcma. Thailand imports pipeline gas from Myanmar (8.8 bcma in 2016) although that may also be in long-term decline. On these trends Thailand's 2025 LNG imports could reach some 23 bcma, up significantly from the 2016 figure of 4 bcma.

Vietnam

Economic and political reforms launched in 1986 have spurred rapid economic growth and development and transformed Vietnam from one of the world's poorest nations to a lower–middle-income country. Vietnam has enjoyed strong economic growth; since 1990, its GDP per capita growth has been among the fastest in the world, averaging 6.4 per cent a year in the 2000s. The country's medium-term outlook remains favourable, with GDP expanding by 6 per cent in 2016.

'SOME 90 PER CENT OF VIETNAM'S GAS CONSUMPTION IS IN THE POWER SECTOR, WITH THE BALANCE IN THE INDUSTRIAL AND FERTILIZER SECTORS.'

After growing at an average annual rate of 7.5 per cent between 2010 and 2015, 2016's primary energy consumption was only 1.8 per cent above that of 2015. Oil consumption has grown consistently over the period (see Vietnam table above). Coal and gas consumption in 2016 fell back or remained flat relative to 2015. Some 90 per cent of Vietnam's gas consumption is in the power sector, with the balance in the industrial and fertilizer sectors. If Vietnam's production fails to grow further, it is possible that the country may turn to LNG imports to meet potential gas demand. This has been anticipated for some while, but its two planned regas terminal projects have been subject to rolling delays. By 2025, Vietnam's gas consumption could grow to some 12 bcma which may require up to 4 bcma of LNG imports, subject to the rate of domestic production decline.

The Philippines

While a slower-than-expected global recovery weakened net exports in 2016, surging domestic demand pushed the annual GDP growth rate to 6.8 per cent. The Philippines' growth outlook remains positive – the World Bank projects that real GDP will grow at a rate of 6.9 per cent in 2017 and 2018. Supported by sound domestic macroeconomic fundamentals and an accelerating recovery among other emerging markets and developing economies, the Philippines is expected to remain one of East Asia's top growth performers.

The Philippines' energy mix is dominated by oil and coal, both of which have grown rapidly since 2010 (see the Philippines table below). In 2016 renewables accounted for 12.3 per cent of primary energy, but this was mainly hydro and non-wind/solar. Gas supply remains confined to production from the Malampaya offshore gas field, discovered by Shell in 1992. The field supplied gas-fired power plants, a refinery in Tabangao, and minor quantities to industrial users. Investment between 2011 and 2015 saw infill drilling and additional compression increase the production

The Philippines primary energy consumption, 2010–16 (million tonnes oil equivalent)

	2010	2011	2012	2013	2014	2015	2016
Gas	3.2	3.5	3.3	3.0	3.2	3.0	3.4
Oil	14.6	13.8	14.4	14.9	16.1	18.3	19.9
Coal	7.0	7.7	8.1	10.0	10.6	11.6	13.5
Hydro and renewables	4.0	4.5	4.7	4.5	4.5	4.7	5.2
Total	**28.8**	**29.5**	**30.5**	**32.5**	**34.4**	**37.7**	**42.1**

Source: BP Statistical Review of World Energy 2017.

Myanmar primary energy consumption, 2009–10 to 2013–14 (million tonnes oil equivalent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Coal	0.3	0.3	0.5	0.5	0.3
Oil	0.7	0.9	0.9	0.7	0.6
Gas	1.2	1.5	1.8	1.9	2.0
Hydro and biomass	9.6	8.7	9.7	9.9	9.3
Total	**11.8**	**11.4**	**12.8**	**12.9**	**12.2**

Source: Myanmar Energy Master Plan.

level from this maturing field in 2016. With field production expected to decline significantly from 2024, there is interest in constructing an LNG FSRU (Floating Storage and Regasification Unit), with installation possibly around 2020. The expectation for Philippine gas demand is therefore around 3.5 bcma in 2025, with the possibility of expansion should more than one FSRU proceed.

Myanmar

Given its size, Myanmar does not receive comprehensive coverage in many energy publications, but given its exports of gas to both Thailand and China, it is worthy of inclusion here. The new government, led by State Counsellor Daw Aung San Suu Kyi, has launched new economic policies. Economic growth in Myanmar is expected to moderate from 7.3 per cent in 2015/6 to 6.5 per cent in 2016/7.

In terms of primary energy consumption, gas is second to biomass in the mix and has grown significantly in relative terms since 2009/10 (see Myanmar table above). Myanmar has been a hydrocarbon producer/exporter since 1853; however, decades of isolation, sanctions, a lack of technical capacity, opaque government policies, and insufficient investment have impeded upstream hydrocarbon sector development. In 2016 Myanmar produced 18.9 bcm, of which 8.8 was exported to Thailand and 3.9 to China (figures from *BP Statistical Review of World Energy 2017*). Of the balance consumed internally: 46 per cent is in power generation, 25 per cent industry, 5 per cent fertilizer, 6 per cent transport, and the balance ascribed to 'other'. While statistics need treating with caution and the country's role as a significant exporter is noted, it is worth following the evolving role of Myanmar as the country hopefully emerges from isolation and develops its energy sector.

Conclusions for south-east Asia

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

'… IT IS WORTH FOLLOWING THE EVOLVING ROLE OF MYANMAR AS THE COUNTRY HOPEFULLY EMERGES FROM ISOLATION AND DEVELOPS ITS ENERGY SECTOR.'

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 five to ten years. Countries where a decline in domestic production or pipeline gas supplies will likely lead to increased LNG imports by 2025 are: Singapore (pipeline supply), Indonesia, Thailand, Malaysia, Vietnam, and the Philippines.

The *second* is uncertainty around the future energy mix and government policy. Thus, subject to international pressure, Indonesia and Malaysia may be 'nudged' away from their apparent coal-focused path and increase their domestic gas consumption. Given the maturity of gas production in Indonesia and Malaysia, such a move would hasten the point at which they would become net LNG importers.

Myanmar has been a major regional south-east Asian gas producer and exporter – to Thailand for some years, and more recently to China. It is a country worth observing in the event that its economic development versus its remaining gas prospectivity may require it become an LNG importer.

Asian emerging markets: non-power sector driving gas demand

Sylvie Cornot-Gandolphe

Non-OECD Asia (comprising: Bangladesh, Brunei Darussalam, Cambodia, China, Chinese Taipei, India, Indonesia, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, the Philippines, Singapore, Sri Lanka, Thailand, Vietnam, and other Asian countries and territories) is the world's third-largest gas consuming region and the driver of global gas demand. The region is expected to double its gas demand by 2030, driven by population and economic growth, urbanization, and industrialization trends. One common driver in all countries is electricity growth, and hence rising gas demand by the power sector. However, while this rise is certain, the power sector is not expected to be the main driver of gas demand in coal-producing countries (China, India, Indonesia – also the major energy markets in the region) which have to import gas. Coal has been the dominant source, so far, for their power supplies: it accounts for 67 per cent of non-OECD Asian electricity generation. As coal is widely available in the region and at a relatively low cost (even after its price increase in 2016), economic and security of supply issues will make it hard to substitute coal with gas. Instead, most countries have adopted policies favouring renewables and high-efficiency coal, complemented by gas (for peaking purposes or in niche markets), rather than a combination of renewables and gas. This strategy allows them to reduce air pollution – the number one enemy in Asia – and also to achieve their intended greenhouse gas emission reductions. Hence, while the power sector had been expected to be the driving force in the growth of regional gas demand, this assumption is being reviewed and the largest growth in gas demand is now expected to come from the non-power sector, and notably the industrial sector.

'AS COAL IS WIDELY AVAILABLE IN THE REGION AND AT A RELATIVELY LOW COST … ECONOMIC AND SECURITY OF SUPPLY ISSUES WILL MAKE IT HARD TO SUBSTITUTE COAL WITH GAS.'

'… THE LARGEST GROWTH IN GAS DEMAND IS NOW EXPECTED TO COME FROM THE NON-POWER SECTOR …'

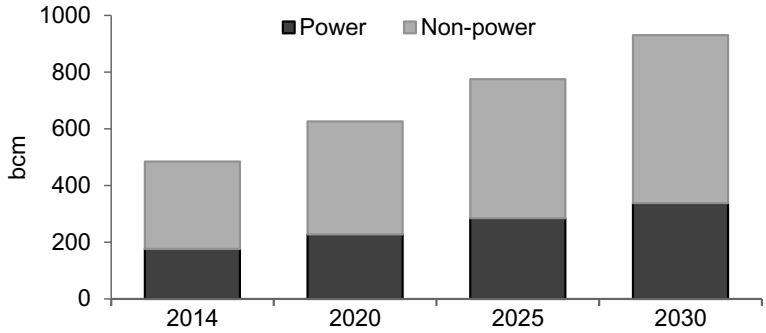
Gas demand driven by non-power sectors

The New Policies Scenario of the IEA's *World Energy Outlook 2016* (WEO 2016) projects non-OECD Asian gas demand to grow from 484 bcm in 2014 to 930 bcm in 2030 (see figure below), which is not significantly different from what was foreseen five years ago (921 bcm in WEO 2011). However, in term of sectoral demand, there has been a significant downward revision in the contribution of the power sector. Gas demand by the sector is now projected at 339 bcm in 2030 compared with 367 bcm in WEO 2011, while projected demand for the industrial sector has been increased from 244 bcm in 2030 in WEO 2011 to 310 bcm in WEO 2016.

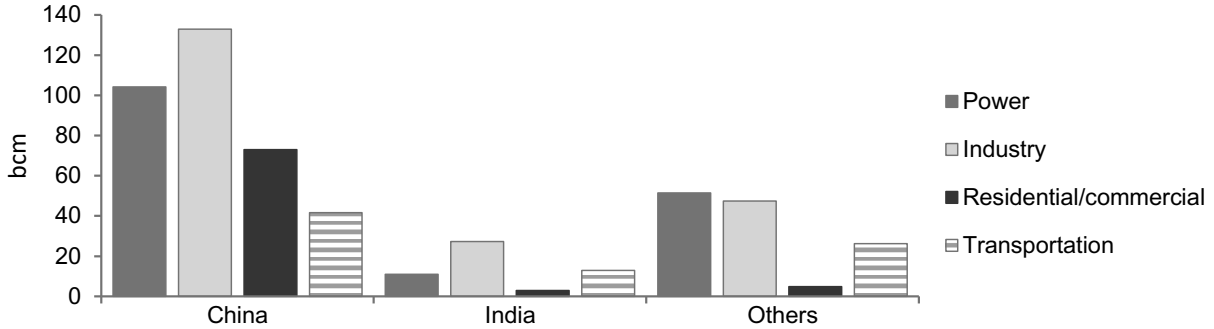
The increase in non-power gas demand is even sharper in the EIA's International Energy Outlook 2016 (IEO 2016). The EIA projects total regional gas demand to increase from 428 bcm in 2013 to 964 bcm in 2030. The industrial sector is the largest contributor, accounting for 39 per cent of the growth, followed by the power sector (31 per cent), and the transportation and residential/commercial sectors (15 per cent each) (see figure overleaf). These projections reflect recent national power development plans adopted in the region.

China

Although gas demand from the power sector in China has increased significantly over the past two decades, the power sector only consumed 18 per cent of China's total natural gas volumes in 2016, much lower than the 44 per cent consumed by the industrial sector (including petrochemicals). Coal still dominates the electricity mix – 65 per cent in 2016, compared with 3 per cent for gas (according to: China Energy Portal, 2016 detailed electricity statistics, 20 January 2017). In the 13th



Outlook for gas demand in non-OECD Asia (power and non-power sectors)
Source: IEA WEO 2016 (original data in Mtoe).



Increase in sectoral gas demand between 2013 and 2030 in major emerging Asian markets

Source: EIA, IEO 2016 (original data in quadrillion Btu).

Five-Year Plan (FYP), the government plans to boost gas use in electricity power generation, increasing gas-fired installed capacity from 66 GW in 2015 to 110 GW in 2020 (according to: 'Five Year Plan (2016–2020) for power', National Energy Administration, 2017). Although significant, the planned capacity is modest compared with coal and renewables (1,100 GW and 700 GW of total capacity by 2020 respectively). Coal-to-gas switching will be limited to niche markets, especially in the four major highly polluted urban areas of eastern China.

'COAL-TO-GAS SWITCHING [IN CHINA] WILL BE LIMITED TO NICHE MARKETS, ESPECIALLY IN THE FOUR MAJOR HIGHLY POLLUTED URBAN AREAS OF EASTERN CHINA.'

India

Despite a small increase in 2015/16, gas demand by India's power sector accounted for only 23 per cent of total gas demand in 2015, far behind the industrial sector's 53 per cent. Gas remains a modest contributor to electricity generation (5 per cent in 2015), which is dominated by coal (77 per cent) (according to: 'Power Sector, Executive summary', Central Electricity Authority (CEA), Government of India, April 2017). The Draft National Electricity Plan, which states that no coal power plant is needed until 2022, focuses on a rapid development of renewables, including hydro (see: 'Draft National Electricity Plan', Central Electricity Authority, Government of India). According to the plan, gas capacity only rises by about 5 GW to 30 GW by 2022. Gas plays a limited role, mostly for peak load purposes to complement the development of renewables. This role could be higher should the government miss its renewables target of 175 GW by 2022 (see: 'India's gas market post-COP21', Anupama Sen, OIES Paper NG120, June 2017). However, the current low utilization factors of coal capacity mean that India has a buffer should this case arise.

Indonesia

Gas accounts for 24 per cent of Indonesia's electricity generation, which is also dominated by coal (56 per cent). The latest electricity supply business plan ('2017–2026 Electricity Supply Business Plan', (RUPTL), PLN, Minister of Energy and Mineral Resources, Directorate General of Electricity, 2017) produced by PLN (the national power utility), has set a higher target for the amount of electricity generated from renewable sources (22.6 per cent by 2026, up from the 19.7 per cent in the previous plan). In turn, the share of gas-fired electricity generation has been reduced to 26.6 per cent, down from 29.4 per cent.

Challenges to increased regional gas use in power generation

Despite the clear role that natural gas can play in reducing CO_2 emissions and air pollution, there are economic, financial, and security of supply issues that conflict with its increased use in the region's power generation.

'THE GAP BETWEEN COAL AND GAS PRICES HAS NARROWED, BUT COAL REMAINS MORE COMPETITIVE THAN GAS …'

Price competitiveness

In most countries, natural gas prices are regulated by governments and are much higher than coal prices. In Asia, wholesale gas prices averaged US$5.8/MMBtu in 2016 (and as high as US$8.3 for the power sector in China), while international coal prices rose to an average of US$80/t (around US$3/MMBtu) in the second half of 2016 (see: '2017 Wholesale gas price survey', International Gas Union). The gap between coal and gas prices has narrowed, but coal remains more competitive than gas, even when the higher efficiency of CCGTs is taken into account. In addition, domestic coal prices do not necessarily follow international prices. For instance, in India, Coal India Limited (the state-owned company) sells nearly 85 per cent of coal through regulated channel

to power plants where prices are fixed annually (less than US$20/t in 2016).

The gap between coal and gas prices will be further narrowed when coal externalities are included. Pricing reforms in that direction have started (cap-and-trade system in China, environmental tax in India), but their full effect is likely to be a long-term one, and not necessarily a factor of coal-to-gas switching in the power sector. An MIT study found that the cap-and-trade system put in place in China would have the effect of decreasing the consumption of coal, but also that of natural gas, and at the current relative prices of fuels, the policy would not result in a switch from coal to natural gas (see: 'The Future of Natural Gas in China: Effects of Pricing Reform and Climate Policy', Danwei Zhang and Sergey Paltsev, *Climate Change Economics*, vol. 7, 1650012, 2016).

'THE REGION LACKS WELL-DEVELOPED GAS INFRASTRUCTURE, TRANSMISSION AND DISTRIBUTION PIPELINES, AND STORAGE.'

Currently, coal-to-gas switching in the power sector hinges entirely on government policies and interventions, since gas is unable to economically compete with coal. Central or local governments have to subsidize gas demand in gas-fired power plants for this demand to remain viable. These subsidies impede the development of a robust and sustainable natural gas market in the power sector.

Security of supply considerations

Although the region has significant natural gas resources, they are not sufficient to cover rising gas demand. Thus, the region is faced with growing imports. Simultaneously, governments in the region promote energy independence and have plans to reduce their energy dependency. This protectionism is a major factor limiting the use of gas in the power sector as other fuels and options are readily available in this sector. On the other hand, it is a powerful argument towards the development of non-fossil fuel energy sources for power generation, especially wind, solar, and nuclear which are domestically controlled resources. Recent changes in upstream policies in the region, which promote the entry of foreign investors, have the potential to reinvigorate the development of domestic gas production, and in turn gas demand by the power sector.

Lack of, or nascent, gas infrastructure

The region lacks well-developed gas infrastructure, transmission and distribution pipelines, and storage. China is the most advanced, but infrastructure is still a bottleneck to gas market penetration even there. Required investment in gas infrastructure is huge in the region. For instance, Indonesia needs to invest US$70–80 billion in gas infrastructure through 2030 to avoid a potential gas shortage, as domestic consumption growth outpaces supply.

This is another constraint on the development of gas in power generation. As underlined by the IEA, investment needs associated with gas-fired power are much larger than those associated with coal-fired power when the outlays required for the full supply chain are taken into account. This explains why coal-fired power generation has been favoured in the region's importing countries. FSRU can bring a viable solution, provided natural gas prices remain relatively low.

Central government allocation of gas to strategic consuming sectors

In most non-OECD Asian countries, the gas market is under the control of governments which direct gas supplies to certain key sectors and prohibit or restrain its use in other sectors.

'… THE GAS MARKET IS UNDER THE CONTROL OF GOVERNMENTS WHICH DIRECT GAS SUPPLIES TO CERTAIN KEY SECTORS AND PROHIBIT OR RESTRAIN ITS USE IN OTHER SECTORS.'

These supply allocations have not favoured the use of gas in the power sector. In *China*, where gas in the power sector was prohibited except for CHP and peaking plants until 2012, the gas utilization policy was reviewed at the end of 2012 and the use of gas in power generation is now permitted, except in major coal producing regions. In *India*, according to its 'Gas Utilization Policy', domestic gas production is allocated in priority to Tier-1 sectors, (which consume about 90 per cent of total domestic production): city gas distribution for households and transport, then the production of fertilizers, LPG plants, and finally grid-connected gas-based power plants. The remaining demand is mostly supplied by LNG. Gas-fired merchant power plants are supplied with LNG to produce power that is often too expensive for the almost-bankrupt electricity distribution companies to purchase (see: 'Current and future natural gas demand in China and India', BEG/CEE, April 2017). This is illustrated by the fact that despite a temporary subsidy scheme launched in 2015 for two years (to facilitate the use of gas in the power sector and avoid gas plants becoming stranded assets), their load factors only increased marginally. In *Indonesia*, the 'Regulation on Determination of Natural Gas Prices', issued in 2016, sets allocation priorities: first, own use and field operation (enhanced oil recovery), second, fertilizer and petrochemical feedstock, then power generation. New rules for the use of gas in the power sector, adopted in March 2017, should boost the use of gas in the sector and facilitate the fulfilment of PLN's recent electricity plan.

Drivers for gas demand increasingly geared towards industry

In non-OECD Asia, the structural demand for natural gas is therefore mainly an alternative to fuel oil products (and to coal in China) in the industrial sector (including petrochemicals). To a lesser extent, it represents an alternative to fuel oil products in the transportation sector. The residential/commercial sector is only expected to rise significantly in China (boosted by the extension of distribution networks and the replacement of small coal boilers used for heating purposes in big cities and their suburbs, as well as in rural areas).

In *China*, coal-to-gas switching in the industrial sector is expected to play a key role to combat air pollution. The 13th FYP calls for using gas instead of coal in industrial boilers throughout the four major highly polluted urban areas in eastern China. This is an important evolution in the energy demand structure, because the share of coal in final energy use, mainly in the industrial sector, is still very high in China (30 per cent in 2015). While local pollution from large coal plants can be controlled with investment in depollution equipment and regulation to enforce stringent standards on local pollutants, the air pollution from the dispersed use of coal is much more difficult to control. Around 700 million tonnes of coal are burned annually in half a million boilers for residential and dispersed industrial sectors (see: 'Medium-term Gas Market Report', IEA, 2016). These boilers, often small, highly polluting, and difficult to retrofit, are a significant factor in local air pollution (see: 'China's coal market: can Beijing tame "King Coal"?', Sylvie Cornot-Gandolphe, OIES Paper CL1, December 2014). Hence, coal-to-gas switching in the non-power sector offers great opportunities for reducing air pollution and increasing gas demand. The potential incremental demand during 2016–20 from coal-to-gas switching in the industrial sector is estimated at 53 bcm (see: 16th U.S.–China Oil & Gas Industry Forum, China's Natural Gas Market Overview, CNPC/ETRI, September 2016). China's provincial governments are supporting the efforts by subsidizing gas supply connections and boiler replacements. The strategic social and economic importance of improving air quality should be a sufficient factor to overcome price and security obstacles and to achieve the coal-to-gas switching potential.

In *India*, fertilizer production (the largest industrial user of gas) is an integral part of New Delhi's emphasis on food production security. This explains why the fertilizer sector receives priority access to domestically produced gas and subsidized prices through the 'gas pooling policy' of March 2015. The fall in natural gas prices since mid-2014, together with the gas pooling policy, have boosted gas demand for the production of ammonia and urea. The government wants to make India self-sufficient in fertilizer production, which will further boost gas demand by the sector. Numerous projects and plans have been announced to re-open idled plants, convert naphtha-based plants to gas, and build new gas-based plants. However, securing capital investment is a major hurdle and none of the announced plants have achieved financial closure so far. In other industrial sectors, future gas demand relies on the success of the 'Make in India' policy, which aims at raising the manufacturing growth rate to 12–14 per cent by 2025. Progress has been muted to date. However, if growth in manufacturing accelerates from current levels, there are significant opportunities to increase gas demand in the non-energy intensive industries such as textiles, food and beverages, transport equipment, and electronics.

'THE INDUSTRIAL SECTOR THEREFORE EMERGES AS THE DRIVING FORCE OF FUTURE GAS DEMAND.'

In other emerging Asian countries, the success of industrialization policies will dictate potential outcomes for gas demand in the industrial sector. In *Indonesia*, demand from the industrial sector is likely to expand as a result of much lower gas prices and new regasification capacity, allowing the country to supplement its indigenous production with imports. Recently, the government adopted regulation to decrease gas prices (less than US$6/MMBtu) to the steel, petrochemicals, and fertilizer industries. To boost price competitiveness, imported LNG has been allowed for these sectors.

Conclusion: different drivers for industrial gas demand

In emerging Asian countries, rising gas demand by the power sector is constrained by economic, financial, and security of supply considerations. The industrial sector therefore emerges as the driving force of future gas demand. In China, this is mainly due to the replacement of coal in industrial applications, driven by the need to improve air quality. In other emerging Asian countries, the rise mainly relies on industrialization policies and the strategic importance of some industries for the economy, such as fertilizers, petrochemicals, and steel.

Prospecting Chinese gas demand

Donna Peng

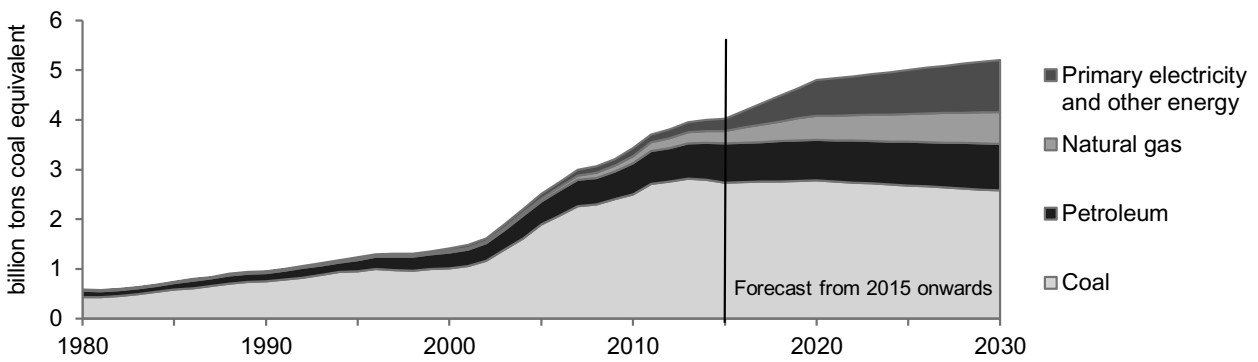
The 12th Five Year Plan for Natural Gas Development (FYP 12, released in 2012) predicted that China's annual natural gas consumption would increase to 230 bcm by 2015, from 110 bcm in 2010 (see: 国家发改委 (2012). 天然气发展"十二五"规划, only available in Chinese). However, the value realized in 2015 was only 193 bcm. Full statistics for 2016 were not available at the time of writing, but a year-on-year increase of 6.6 per cent in demand (giving a figure for gas consumption of 205.8 bcm) was reported by the National Development and Reform Commission (NDRC), indicating a continuation of lower growth relative to the previous decade of double-digit growth. The 13th Five Year Plan (FYP 13) for natural gas, published by the NDRC in January 2017, revised the 2020 target for the share of gas in China's primary energy supply to 8.3–10 per cent. This indicates a downward shift in expectations compared to the FYP 13 for the energy sector in general (published in December 2016), where the target was announced to be 10 per cent. Is slowing gas consumption temporary or a lasting trend? In this brief outlook, we explore the factors that influence Chinese gas demand in the short term (up to 2020) and the long term (up to 2030).

Chinese energy consumption

The five years (2016–20) covered by FYP 13 are critical to the Chinese economy, as the government manages the immediate effects of transitioning to the 'New Normal' – an age of slower and qualitatively different economic growth. Planned macro policies aimed at transforming industry structure and rebalancing the Chinese economy are expected to slow the growth of the country's energy consumption, energy intensity, and carbon emissions, a departure from the rapid industry-driven growth powered by coal seen in the previous three decades. In 'China Energy Outlook 2030', the China Energy Research Society forecasts an average annual energy consumption increase of 1.4 per cent between 2016 and 2030, much lower than the average annual growth rate for the preceding 15-year period (7.6 per cent). Combining their 2030 forecast with the FYP 13 for the energy sector, we obtain the energy consumption structure illustrated in the figure below: stabilized coal and petroleum consumption, with natural gas and non-fossil fuel energy contributing to the bulk of the increase in energy demand. This forecast embodies Beijing's strong preference for gas as part of its future energy mix. The forecast of natural gas demand within such an energy mix trajectory amounts to about 360 bcm for 2020 (10 per cent of total energy consumption) and 480 bcm for 2030 (12 per cent of total energy consumption). The forecast for the relative share of gas in 2030 remains well below the figure for the world average (23.7 per cent in 2013). However, how does such a top-down forecast compare with a bottom-up view based on potential developments in sectoral gas demand?

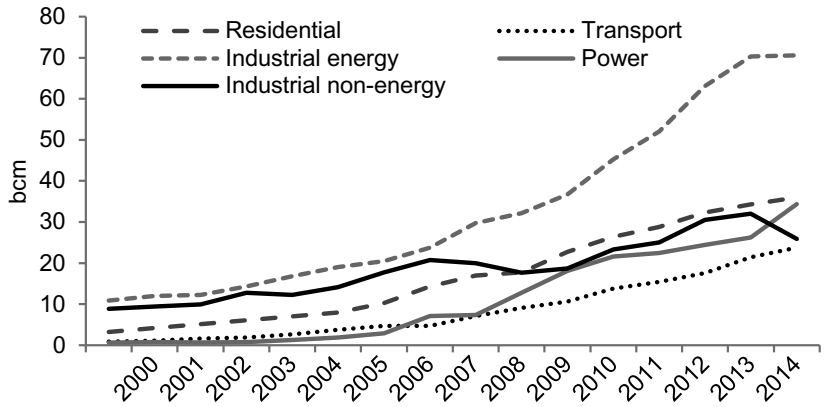
'THE FORECAST FOR THE RELATIVE SHARE OF GAS IN 2030 REMAINS WELL BELOW THE FIGURE FOR THE WORLD AVERAGE.'

In 2015, natural gas demand reached 193 bcm. The industrial energy sector was the main consumer and historically the fastest growing market, as illustrated in the figure overleaf. It accounted for 37 per cent of total gas consumption in 2015. The residential sector was second with 18.9 per cent, followed by power (18 per cent), industrial non-energy (13.6 per cent), and finally transport (12.5 per cent).



Chinese energy consumption by fuels, 1980–2030

Source: Based on data from China Energy Statistical Year Book 2016, FYP 13 for energy, and 'China Energy Outlook 2030'.



Breakdown of Chinese gas demand by sector

Source: Based on data from China Energy Statistical Year Book 2016, database of the National Bureau of Statistics.

The Natural Gas Utilization Policy of 2007, representing the Chinese central government's perception of the efficient use of natural gas, allocated different priorities (prioritized, permitted, restricted, prohibited) to gas utilization projects in different sectors. Despite updates in 2012, the priorities remain clear: gas demand from the residential and transport sectors is prioritized, fuel switching in the industrial sector from oil and coal to gas and gas-fired generation are permitted, whereas low-value use of gas as chemical feedstock and gas-fired generation in major coal producing regions is restricted or prohibited.

Outlook for sectoral gas demand

Gas sector reform

The gas pricing reform of 2013 introduced some market mechanisms into a previously highly regulated regime (see: 'The development of Chinese gas pricing: drivers, challenges and implications for demand', Michael Chen, OIES Paper NG 89, July 2014; 'Natural gas pricing reform in China: Getting closer to a market system?', Sergey Paltsev and Danwei Zhang *Energy Policy, 86, 43–56, November 2015*; 王璐 (2016, June). 天然气价格改革再获推进. 经济参考报 ('Natural gas price reform is advanced'), *Energy People, 27 June 2016*). The plan was to gradually increase the price of non-residential gas to resolve misalignment between import and end-user prices and to provide incentives for the expansion of domestic supply. However, the sharp decline of the global oil price in late 2014 required a change in planned price movements: in 2015, the price of non-residential gas was revised downward.

'THE GAS PRICING REFORM OF 2013 INTRODUCED SOME MARKET MECHANISMS INTO A PREVIOUSLY HIGHLY REGULATED REGIME.'

By 2017, we can differentiate three forms of pricing practice in China.

1 The price of gas supplied to direct users (which are mainly power generators and industry customers), as well as the price charged for select gas supplies, is now open to bilateral negotiation.

2 The price charged by gas suppliers to non-residential customers which remain under regulation (small industry and transport users purchasing gas from local distribution companies) is loosely anchored by a centrally determined city gate price, periodically updated according to the price of competing fuels.

3 The gas supplied to residential customers remains subject to more stringent regulation and is not subject to regular updates.

In November 2015, after the downward revision, the centrally determined city gate price for Beijing was US$8.4/MMBtu (exchange rate used: 1 US$ ≡ 0.16 RMB). According to the Beijing Municipal Commission of Development and Reform (a regional price setting authority), gas distributed to power generators in Beijing is capped at US$10.6/MMBtu, industry gas is capped at US$13.3/MMBtu, and compressed natural gas for non-residential use (such as transport) at US$10.4/MMBtu. Tiered prices for residential customers range from US$9.6 (household annual consumption $<350\ m^3$) to US$16.5/MMBtu (household annual consumption $>500\ m^3$).

Residential sector: growing for now

Despite the slowdown of economic growth, the size of the urban population relative to the total is expected to grow steadily. Meanwhile, the planned increase in urban distribution infrastructure will continue to increase this population's access to natural gas. Between 2015 and 2020, the size of the population with access to gas is projected to increase from 330 million to 470 million. Given the policy priority of increasing residential gas consumption and regulating residential gas prices stringently, the price of natural gas for residential consumers is expected to remain competitive relative to LPG in the short term. All these factors contribute positively to growth in residential gas demand from now to 2020.

Although the relatively low residential gas price is favourable to short-term growth in this sector, the sustainability of such an approach is questionable because gas distribution companies

will need to compensate the low regulated residential price by cross subsidy from non-residential customers connected to the distribution grid (embedded industry customers and natural gas vehicles users). Another consequence of growing residential gas consumption is the increasing strain being put on existing gas infrastructure: during winter when heating demand for gas is high, regional scarcity-induced outage is often observed due to inadequate storage capacity. Therefore, growth in areas where residential consumption is already significant may become constrained. Tiered pricing, designed by regional authorities based on central guidelines, has been rolled out in an increasing number of cities to promote more efficient residential gas consumption. The increased revenue collected from those with above-average consumption is to be used to reduce cross subsidy to the residential sector and to invest in gas peaking/storage infrastructure. The successful implementation of such retail-end price reform underpins the development of residential demand in the long term.

Transport sector: on its feet

Between 2010 and 2015, the number of natural gas vehicles in China increased from 1.1 million to 5 million, making China the country with the highest number of such vehicles in the world (see: 王韬 (2016). 天然气在中国交通运输领域的应用 ('Natural gas in China's transportation'), Gas Technology Institute, CBN Research Institute, March 2016). Despite being prioritized among gas utilization applications in national policy, and a FYP 13 plan to increase the number of gas vehicles to 10 million by 2020, policy support to natural gas vehicles is being eclipsed by support to electric vehicles. Generous subsidies to manufacturers and users of electric vehicles, dubbed 'new energy vehicles', are handed out by both central and regional governments, while support to gas vehicles has been less focused and more indirect, either in the form of grants for regional emission reduction projects or tax credits to LNG-fuelled trucks. Some regional efforts – such as public procurement of gas-fuelled buses – have been phased out in favour of electricity-powered buses. This suggests that government financial support cannot be relied on to boost transport sector gas demand. Instead, gas vehicles will need to compete on the basis of their own merits in the market.

'BETWEEN 2010 AND 2015, THE NUMBER OF NATURAL GAS VEHICLES IN CHINA INCREASED FROM 1.1 MILLION TO 5 MILLION …'

Compared to conventional oil-fuelled vehicles, natural gas vehicles have a higher upfront purchase cost, but lower operation and maintenance costs and lower fuel costs for the same distance travelled. Most natural gas vehicles in use are converted dual-fuel passenger cars, whose demand for gas is highly sensitive to the price ratio between gas and gasoline or diesel. The remainder of the gas fleet consists mainly of gas-fuelled buses and heavy-duty trucks, which benefit from lowered operational costs given the long distances they travel. The relative price competitiveness of natural gas in transport was disrupted in 2014 when the oil price fell, while the anchoring city gate price for non-residential gas use increased as part of the gas pricing reform. In 2015, falls in the newly oil-linked city gate price helped to re-balance the price ratio between the two fuels. Since most existing users of natural gas vehicles are motivated by fuel cost savings relative to gasoline, consumption of gas in this sector will continue to be driven by the relative difference between the prices of the two fuels. The current price competitiveness of gas, and thus transport sector consumption growth, is expected to be maintained into the 2020s. But, as the Chinese economy slows, the speed at which new natural gas vehicles are added is expected to slow.

Power generation: a pending reform

The 2007 Natural Gas Utilization Policy categorized the use of gas by peaking gas power plants in important load centres (such as Beijing–Tianjin–Hebei, Yangtze River Delta, and Pearl River Delta) as one of its priorities. Gas-fired generation in non-important load centres was permitted, whereas baseload gas-fired power generation in major coal-producing areas was prohibited. The 2012 update maintains a mixed attitude toward power generation using gas. Both the short-term and long-term development of gas-fired generation is mired in uncertainty.

'BOTH THE SHORT-TERM AND LONG-TERM DEVELOPMENT OF GAS-FIRED GENERATION IS MIRED IN UNCERTAINTY.'

Since 2004, power generators in China have been selling their output to regional grid companies at regionally determined and centrally approved cost-based wholesale prices, differentiated by fuel type. The grid operators then sell electricity to retail customers at regulated prices differentiated by end use and voltage level. Wholesale and retail prices across regions are significantly different: in the remote Qinghai province, the approved wholesale price for coal generators is US$0.05/kWh and the retail price for small commercial users is US$0.09/kWh; in Guangdong province, the corresponding prices are US$0.07/kWh and US$0.14/kWh. Wholesale prices for gas-fired power plants are determined

on a case-by-case basis by regional authorities. Allocation of generation quotas is determined administratively by provincial governments based on a 'fair dispatch' principle, with the aim of providing all investors with an equitable chance of cost recovery (see: 'China's power generation dispatch', Mun S. Ho, Zhongmin Wang, and Zichao Yu, RFF Report, April 2017).

In the short term, since gas-fired generators are now able to directly negotiate with suppliers to procure their fuel (as part of the gas pricing reform), the competitiveness of gas-fired generation has improved. This explains the rebound in power sector gas consumption in 2015. However, the cost of gas-fired generation remains above that of coal-fired generation: for a coal price of US$45–75/ton (applicable from 2015 to now) the fuel cost of coal-fired generation is US$0.014–0.02/kWh; whereas for a gas price of US$8–10/MMBtu, the fuel cost of gas-fired generation is US$0.057–0.07/kWh. In 2015, the average wholesale price realized by gas generators was US$0.12/kWh, while that realized by coal generators was US$0.06/kWh (see: 国家能源局 (2016). 2015年度全国电力价格情况监管通报 (National Energy Price Regulatory Bulletin), 1 November 2016). Therefore, only developed regions with higher retail electricity prices can afford the high wholesale prices required by gas-fired generators to recover costs. Also, the use of existing gas peaking plants in some areas is constrained by the lack of flexibility in gas infrastructure, because electricity peak demand often coincides with gas peak demand in winter.

In the long term, the outlook for gas-fired generation depends on the fundamental shifts currently occurring in the power sector. China has the world's largest power system by installed capacity and generation, and its industrial demand, expanding rapidly between the early 2000s until 2012 (when the Chinese economic slowdown became observable) dominates all other sources of electricity consumption. Since the early 2010s, investment in predominantly coal-based new power generation has outpaced slowing demand growth. A 2015 report from North China Electric Power University, commissioned by Greenpeace 袁立海 (2015). 中国煤电产能过剩与投资泡沫研究, Greenpeace, 8 November 2015) forecasts that by 2020, assuming the projects planned by 2015 all come online, the surplus in coal-fired capacity will be 200 GW (about 13 per cent of total installed capacity in 2015, or almost four times higher than UK peak power demand). The over zealousness of investment in coal-fired power plants is attributed to the devolution of coal power plant approval rights to provincial governments, such that projects were approved to boost regional GDP growth despite warnings from the centre. FYP 13 for electricity announced that the central government plans to cancel or delay 150 GW of coal projects under construction and planning. The success of such efforts to curb the building of coal projects may reduce absolute surplus, but the supply/demand balance in the power system will remain loose until at least 2020, depressing the utilization of power plants in general and discouraging new investment.

Given that previous attempts at power sector reform were repeatedly thwarted by power shortages, the surplus situation is perceived as being favourable to the latest round of reform – aimed at introducing competition. Like its counterpart in the gas sector, power sector reform starts with enabling bilateral negotiations between generators and direct users, freeing them from the need to adopt regulated wholesale prices which do not accurately reflect supply/demand situations. In the long term, if power sector reform is successful in introducing more competition and the cost of gas-fired generation is competitive, we could see more market-driven growth in gas consumption. By July 2017, China will be launching its national carbon trading scheme, a development which, in theory, can make gas generation significantly more attractive.

Industrial energy use: growing, but at what pace?

Upward changes in the gas price for industry in 2013/14 decreased the competitiveness of gas as an industrial fuel. But, after the downward adjustment of the gas price in 2015 and the introduction of bilateral contracting for large grid-connected industrial customers, industrial energy demand is expected to rebound. However, this rebound is delimited by the growth in overall industrial energy consumption, which is slowing as part of the 'New Normal' economic transition.

'… BY 2016, THE URGENCY OF COAL-INDUCED AIR POLLUTION PROBLEM WAS DEEPLY FELT THROUGHOUT CHINA …'

The long-term development of industrial energy demand is more uncertain, for it is dependent on the successful implementation of policy-pushed (as opposed to demand-pulled) coal-to-gas conversion. Fuel switching in the industrial sector was permitted, but not prioritized, by the 2007/2012 Gas Utilization Policy. However, by 2016, the urgency of coal-induced air pollution problem was deeply felt throughout China – such that 18 provinces and regions announced policies to enforce coal-to-gas or coal-to-electricity switching in residential and industrial sectors. Capital grants and/or fuel subsidies

have been offered to promote such conversion projects. However, the extent to which these will suffice as an incentive for industry is uncertain. The launch of a national carbon trading scheme in July is expected to decrease the economic obstacles to fuel switching. Nevertheless, we do not expect the ambitious administrative targets to be met on time.

Industrial non-energy use: stagnation

The production of natural gas-derived compounds is very sensitive to variations in the price of the feedstock. The abrupt fall in non-energy consumption of gas in 2015 by 6 bcm (19 per cent) reflects the upward adjustment in the industrial city gate price as part of the gas sector reform in 2013/14. Downward revision of the gas price in 2015 is expected to have alleviated part of this pressure, leading to some rebound in consumption. But because the 2007 and 2012 Natural Gas Utilization Policies either restrict or prohibit investment in new chemical manufacturing capacity using natural gas as a feedstock, no significant growth in this sector is expected in the long term.

Conclusions

Our analysis of sectoral gas demand suggests that the unrevised FYP 2013 target (360 bcm for 2020) is rather optimistic, representing a view that policy-pushed coal-to-gas conversion in the industrial sector will occur promptly. On the other hand, the long-term forecast (480 bcm for 2030) is more realistic; although demand for industrial non-energy use is expected to stagnate, residential and transport sector demand is expected to continue growing. Also, more coal-to-gas conversion in the industrial sector will have been completed within that time frame. Long-term demand for power generation, however, remains most uncertain, given significant oversupply and pending reform in the power sector.

Disentangling short and long-term determinants of gas demand in India

Anupama Sen

A number of factors have put India in the spotlight as a potential future growth market for gas. Among these are: the decline of gas in European energy balances, the USA's transformation from energy importer to exporter, a tempering in China's rapid pace of economic expansion, and the expectation of an oversupplied gas market up to the mid-2020s.

The view on gas from within India has, on the other hand, been in constant flux, with no realistic vision or long-term objectives on its role in the energy mix. No confident assessment of gas demand in India has been possible, as its gas market as a whole has comprised two segments:

- one segment using gas allocated at regulated prices,
- the other sourcing imported LNG at market prices.

Some degree of overlap between the two segments makes the picture even messier. Consequently, government projections of future demand have tended to be overly optimistic, and international assessments cautious. India's ratification of the COP21 agreement and its globally publicized push towards ramping up renewables have thrown further doubt over the role of gas in its future energy mix.

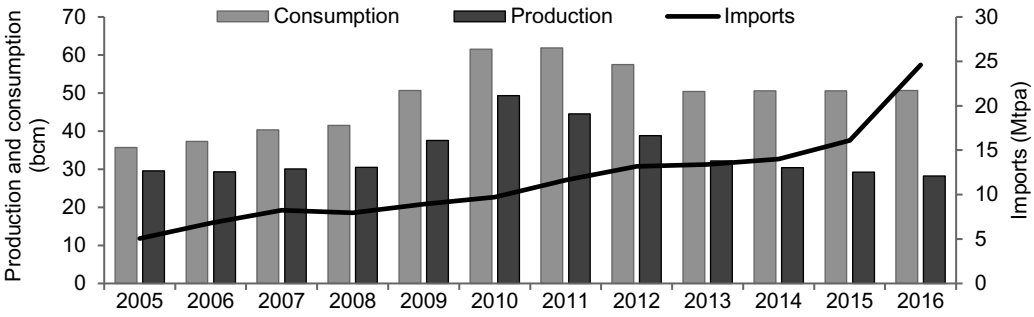
'INDIA IS A "WILDCARD" IN THE GLOBAL GAS MARKET.'

Yet a developing country of over one billion people cannot be confidently dismissed as an important future centre of gas demand. In other words, India is a 'wildcard' in the global gas market. Rather than making predictions, this article aims to disentangle the multiple determinants of India's gas demand into short and long-term factors, and present a broad yet informed framework for assessing its future prospects.

Recent developments

A surge in LNG imports (2015/16) propelled India back onto the radar of international gas markets (see figure overleaf). In March 2014, India imported around 27 per cent of consumption; by September 2015 this had risen to a three-year (2014–17) peak of 50 per cent, dropping marginally to 47 per cent by February 2017. An important feature of the upsurge related to the composition of imports: while percentages of spot/short-term and long-term contracted imports were 18 and 82 per cent in 2010, by 2015/16 the proportions had nearly equalized. This reflected a wider preference amongst Asian buyers for flexible supplies, following the global

'A SURGE IN LNG IMPORTS (2015/16) PROPELLED INDIA BACK ONTO THE RADAR OF INTERNATIONAL GAS MARKETS.'



Indian gas production, consumption and imports

Source: BP Statistical Review of World Energy 2016; Petroleum Planning and Analysis Cell (2016).

gas price downturn. This was also evident in India's 2014 domestic gas pricing reforms, under which prices were delinked from crude oil and linked to a volume-weighted average of international price benchmarks including three hubs – Henry Hub, NBP, and Alberta. (Incidentally, the low price produced by these reforms did not encourage a revival in domestic production, down by 43 per cent since 2010).

In absolute terms, LNG imports grew by 70 per cent from 2014 to 2016 (from 13.9 Mtpa to 24.6 Mtpa), with 2016's imports more than twice their 2010 level. This raises questions around whether the upsurge is sustainable, or merely a short-term outcome of low LNG prices. The answers would need to consider India's two-tier structure of gas demand.

All domestically produced gas is first released to 'Tier-1' consumers consisting, in order of priority:

1 City gas for households and transport.

2 Fertilizer plants.

3 LPG shrinkage plants.

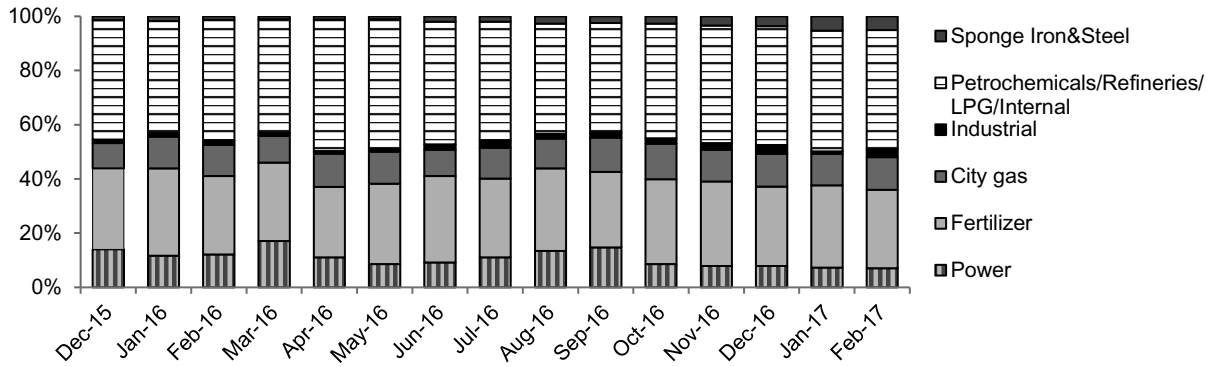
4 Grid-connected gas-based power plants.

The remainder is then released into a general 'Tier-2' group comprising: steel, refineries and petrochemical plants, city gas for commerce and industry, captive/merchant power plants, and other commercial consumers. The LNG upsurge was driven in large part by Tier-2 consumers (see figure below).

Short-term drivers of demand

A better understanding of short-term drivers can be gained from looking at the underpinning economics of demand in the fertilizers, power, city gas, and industry sectors.

In fertilizers, gas competes on price with imported naphtha and imported urea in the manufacture of 25 Mtpa of urea (comprising the major proportion of fertilizer products produced in India), towards meeting India's total urea demand of 33 Mtpa. India's urea manufacturing capacity is 90 per cent gas based, with plans to convert the entire fleet to gas, creating a 'captive' market. Since January 2015, the Indian government has operated a pooling mechanism under which urea plants communicate their gas requirements to a pool operator, which sources incremental supply from LNG imports, pools it with domestic gas, and sells it to urea producers at a uniform average price. There is a 50 per cent subsidy on the retail price of urea to the farmer



Sector-wise consumption of LNG imports, December 2015–February 2017

Source: Petroleum Planning and Analysis Cell (2016).

– an important electoral constituency – amounting to a fiscal cost of US$8 billion/year. Demand in this sector is underpinned by short-term targets to expand domestic urea manufacturing capacity to 38 Mtpa by 2024, and end urea imports. Going forward, the subsidy is likely to be streamlined rather than removed, with payments going directly into the bank accounts of farmers and fertilizer marketing companies under a major ongoing social security reform.

Analyses from a paper by the author ('India's gas market post-COP21', Anupama Sen, OIES Paper NG120, June 2017) show that gas struggles to compete with coal in the power sector at a price beyond US$4.55/MMBtu (at an electricity price of around 3 rupee/kWh on a variable cost basis for existing plant) in the merit order dispatch. Furthermore, electricity tariffs to end users are regulated by state governments and are on average 20 per cent below the cost of supply, making pass-through of higher-priced LNG politically difficult. Consequently, although electricity presents the most substantial short and long-term prospect for gas (India's government has set a goal of extending electricity access to all of India's 1.2 billion citizens by the end of the decade) around 18 GW of 25 GW of gas-fired capacity has remained idle, with gas languishing at 8 per cent of total installed capacity (of 329 GW). A 'pooling' mechanism (similar to fertilizers) was adopted for gas-based power in January 2015 to moderate the price, supported by state tax exemptions and discounts on transportation tariffs, but this was ended in February 2017, partly due to its failure to lift gas-based plant load factors (23 per cent in late 2016) substantially, and partly to the reluctance of states to continue offering tax exemptions.

In contrast, the economics of demand in the city gas sector are more favourable; an analysis from the aforementioned paper shows that Compressed Natural Gas (CNG) remains competitive with its main substitute – diesel – in transportation, at gas prices up to US$5.50/MMBtu, despite the comparative advantage that diesel has had with low international oil prices. This is largely because India's state and federal taxes make up a major component (48 per cent) of the retail prices of diesel, on which states rely for fiscal revenues. Piped Natural Gas (PNG) used by households for cooking is competitive with its main substitute, Liquefied Petroleum Gas (LPG), which is sold at both subsidized and commercial prices, at gas prices of US$3.50–4.50/MMBtu. Retail prices of city gas are deregulated, and distribution companies can pass-through costs to consumers. The expansion of the city gas sector is underpinned by government plans to extend it to 228 new cities (from around 55). This expansion is primarily to combat worsening urban air quality, and gas demand has grown at double digits, albeit from a low base (CNG vehicles have, for instance, grown to 12 per cent of the car-plus-bus fleet over the last few years). However, slow infrastructure development has impeded the scaling up of the sector – for instance, there is just one CNG filling station for every 2,438 vehicles. Consequently, in 2015 and 2016 only a third of forecasted demand was achieved in this sector.

'THE EXPANSION OF THE CITY GAS SECTOR IS UNDERPINNED BY GOVERNMENT PLANS TO EXTEND IT TO 228 NEW CITIES.'

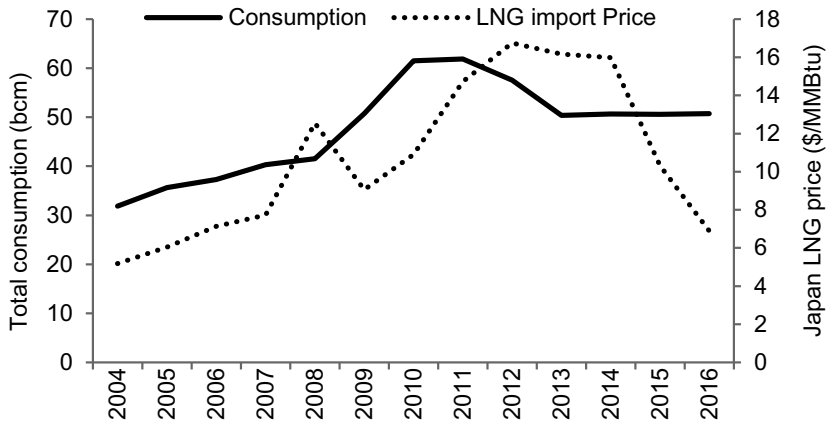
Industrial sector demand covers: petrochemicals, refineries, sponge iron and steel, and LPG shrinkage. Gas competes primarily with naphtha, domestic coal, fuel oil, and imported ethane in these sectors. The outlook for growth in the petrochemical, refinery, and LPG shrinkage sectors is strong – the first two are underpinned by targets aimed at increasing the share of manufacturing in GDP from 15 to 25 per cent of GDP by 2022, while LPG growth is being driven by a goal to replace the use of kerosene in rural areas and increase the number of consumers by 42 per cent from current levels (around 190 million) by 2020. Gas demand in the sponge iron and steel sector will, on the other hand, be limited in the short term, largely due to the global overcapacity in steel.

Long-term determinants of the prospects for gas

The discussion above has discussed the short-term economics of demand; however, there are four long-term factors that are likely to influence the same, shaping the broader outlook for gas.

Global gas prices

As Howard Rogers points out (see: 'The forthcoming LNG supply wave: a case of "Crying Wolf?"', Howard Rogers, OIES Energy Insight, February 2017), given the less than firm commitment to the growth of gas seen in the energy polies of many Asian countries, future LNG price levels will be an important determinant of demand. As is shown in the figure overleaf, Indian gas consumption has a lagged inverse relationship to LNG prices. Should prices remain low in the short to medium term (five year), consumption in key economic sectors should continue to rise. However, not just levels, but price formation mechanisms are critical to the outcome. If the majority of imports are based on oil-linked contracts, low LNG prices would presumably lag low oil prices – and given that oil products are substitutes to gas in industry (for example in petrochemicals and refineries) this would limit the potential for gas growth, even at low LNG prices.



Indian gas consumption and LNG prices

Source: BP Statistical Review of World Energy 2016.

Renewables policy

India has adopted a target to increase the share of renewables (excluding large hydro but also low-carbon nuclear) in installed electric power capacity to 175 GW (100 GW solar, 60 GW wind and 15 GW others) by 2022, from current levels (57 GW at present – or 17.4 per cent of installed capacity). This complements its international commitments under COP21, which include reducing the emissions intensity of GDP by a third by 2030 from 2005 levels, and procuring 40 per cent of 'non-fossil-fuel' electric capacity by the same date. The successful achievement of this target could exclude a long-term role for gas in power, limiting it to a balancing function alongside hydro, adding only 4.34 GW to the existing 24 GW of gas-based capacity through to 2027 (see: Draft National Electricity Plan, Government of India, December 2016).

India will, however, need to add roughly 20 GW of renewables capacity every year to achieve this ambitious target. Although solar tenders/auctions in India have yielded some of the lowest global tariffs (at US$0.04/kWh), there are questions around 'aggressive' bidding by solar companies offering low tariffs which do not adequately price in risk, their ability to deliver contracted capacity on schedule, and the ability of Indian power distribution utilities (which have been negatively impacted by electricity subsidies to consumers) to offtake the electricity. As current auctions are based on a 17 per cent plant capacity utilization factor, there are also questions around whether tariffs could later rise as the costs of integration rise with the scaling up of intermittent renewables. Combined with a history of 'slippage' in the completion of large hydro projects (due to delays in land acquisition and environmental clearances), this could imply a larger long-term role for gas in electricity.

Coal and environmental air pollution

At 300 billion tonnes, India has the world's fourth-largest coal reserves, and 60 per cent of the country's installed power capacity is coal-based, directly competing with gas in power generation. There are two main countervailing factors in coal which will shape the future outlook for gas:

- on the one hand, a push to increase coal production, cease coal imports, mitigate electricity shortages, and provide universal electricity access to all households by the end of this decade; and,
- on the other, fiscal and environmental restrictions on burning coal in order to reduce air pollution and particulate matter emissions, in response to litigation by citizens over inaction on worsening urban air quality.

'INDIA HAS THE WORLD'S FOURTH-LARGEST COAL RESERVES, AND 60 PER CENT OF THE COUNTRY'S INSTALLED POWER CAPACITY IS COAL-BASED…'

India has successfully managed to increase coal production over the last three years, potentially having reduced imports by 20 per cent in 2017 (from 2016 levels), through a slew of reforms aimed at removing inefficiencies in the supply of coal to power plants. These reforms have helped narrow India's overall power deficit to a record low of 1.6 per cent in 2017. India has been less successful in enforcing new regulations on coal-fired power plants aimed at reducing particulate emissions by 90 per cent, nitrogen oxide emissions by 70 per cent, and mercury emissions by 75 per cent, from 2017 onwards (to improve ambient air quality). One of the reasons for the delay is continuing uncertainty over whether the associated costs of compliance for firms will be passable into electricity tariffs. India introduced a tax per tonne of coal production in 2014; this currently stands at US$6, nowhere near enough to dis-incentivize the use of coal relative to gas, which would require a fivefold increase, to nearly US$30/tonne.

Although there have been delays in enforcing environmental regulations, Indian policymakers are banking heavily on achieving the renewables target to mitigate any increased requirements for (and negative externalities from) coal, rather than considering gas as a transition fuel. India's Draft National Electricity Plan (2016) assumes that the 175 GW renewables target will be met, then grow to 275 GW by 2027; therefore no new coal-based power plants, beyond

those already under construction (amounting to roughly 50 GW and expected to be made operational during 2017–22), will be required until at least 2026/7. India had around 178 GW of coal project proposals in the pipeline in 2016, but since then there has been a spate of cancellations of coal projects – for instance in May 2017 alone, coal projects amounting to 14 GW were cancelled across three states.

Infrastructure

Infrastructure lies at the heart of optimizing India's potential as a major gas market and is worthy of a separate discussion beyond the scope of this article. But there are two main bottlenecks: first, pipeline infrastructure is not being built quickly enough to support demand in growing regional markets; and second, parts of existing infrastructure remain underutilized (average capacity utilization of around 141 bcm of pipelines covering 16,000 km is 40 per cent). Two of India's four regasification terminals (25 Mtpa) are running at low capacity – Dabhol due to the prolonged delay in constructing a breakwater facility and Kochi due to the delay in laying connecting pipelines. Overall, three factors are impeding the development of infrastructure:

- The 'commodity versus carrier' problem, where infrastructure companies are reluctant to lay pipelines without anchor consumers, and the latter are reluctant to enter into offtake agreements before infrastructure has been completed.
- Legislative problems at the state level, affecting the right to use land for pipeline construction.
- The lack of a clear regulatory framework and strong mandate for the downstream regulator (India's Petroleum and Natural Gas Regulatory Board) which administers the tenders for building city gas infrastructure.

'INFRASTRUCTURE LIES AT THE HEART OF OPTIMIZING INDIA'S POTENTIAL AS A MAJOR GAS MARKET …'

Outlook for natural gas demand in India: drivers and determinants

	(A) Main driver(s)	(B) Determinants	(C) Relative influence of (B)
Short-term outlook	> Fertilizers > Industry > City gas	• Prices	*Low*
		• Renewables policy	*Low*
		• Coal and environmental policy	*Low*
		• Infrastructure	*High*
Medium-term outlook	> Power	• Prices	*High*
		• Renewables policy	*High*
		• Coal and environmental policy	*High*
		• Infrastructure	*High*
Long-term outlook	> Power	• Prices	*Low*
		• Renewables policy	*High*
		• Coal and environmental policy	*High*
		• Infrastructure	*Low*

Source: Author.

Arguably, a resolution of the third factor would enable resolution of the first two.

Broad framework for assessing gas demand prospects

The table above summarizes the interplay of the short-term drivers and the long-term determinants in a suggested framework for assessing gas demand prospects. These three broad 'outlooks' are more thoroughly discussed in the aforementioned paper by the author ('India's gas market post-COP21').

- *Outlook 1 – A continuation of the status quo to 2024, underpinned by sector-specific growth targets*. Gas demand growth will continue to be driven by the underpinning policy targets in fertilizers, industry, and city gas discussed earlier. This would form a limited but reliable demand base for gas, demand for which will continue to grow comfortably in the short term to 2020 (potentially increasing by 30 per cent from 2015 levels of 37.8 bcm), but there is also some potential to scale up thereafter (growing by around 40 per cent from 2015 levels to 2024). The main constraint to this outlook is the speed of building infrastructure.
- *Outlook 2 – Renewables targets are not met, potential for gas to fill the gap to 2027*: This is predicated on a failure to fully achieve the renewables target, with significant opportunities for gas in the power sector. The projections in Outlook 2 could imply a requirement for 35 bcm of additional gas in the power sector by 2022, rising to nearly 100 bcm by 2027. However, this is also a highly uncertain outlook constrained by prices, infrastructure, renewables policy, and coal policy – particularly as very little additional gas power infrastructure is currently being planned for.
- *Outlook 3 – Coal is actively discouraged in the power sector, opening an important and immediate role for gas in the power sector to 2027 and beyond*: This is based on proactive fiscal policies to promote coal-to-gas switching in the power sector, resulting in the most substantial, and anchoring role, for

gas in the power sector. However, it would require a nearly fivefold increase in the current US$6/tonne tax on coal production and a potential 30 per cent increase in associated electricity tariffs (or equivalent subsidy) – also making this a highly improbable outlook. It is difficult to put firm estimates on this outlook, although theoretically the potential could be as much as 198 GW (coal-based capacity which could potentially be substituted by gas) as of 2017 plus a further 50 GW of coal-based capacity under construction. This outlook is, however, entirely constrained by renewables policy and policy on coal and air pollution.

The most likely outcome is potentially some combination of the first (short-term) and second (medium-term) outlooks. This article has emphasized the highly dynamic nature of the Indian market post-COP21, making the point that the short-term dynamics and longer-term determinants could effectively be studied in a number of combinations and permutations, in order to garner a better understanding of the Indian market as it evolves and develops towards meeting India's key energy policy goals.

Natural gas demand in the Middle East: trends and issues

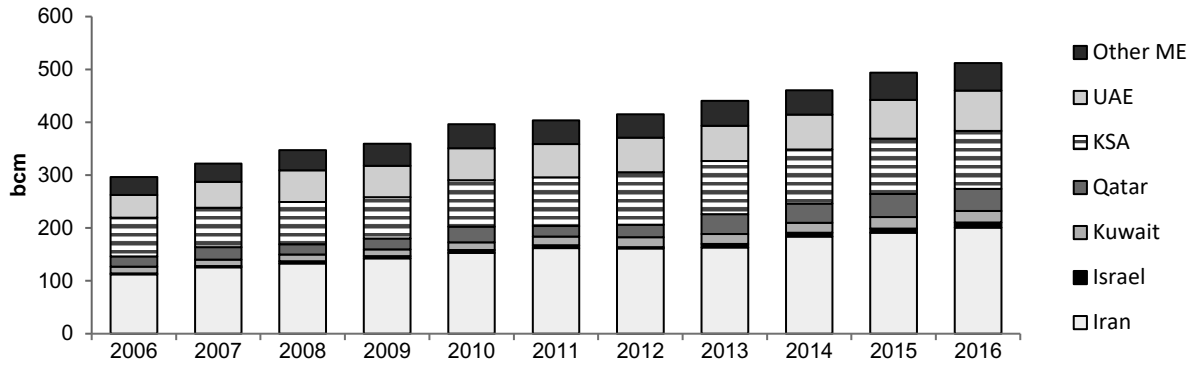
Ieda Gomes

The Middle East comprises 13 countries with a total population of around 200 million people, approximately 2.6 per cent of the world's population. The region is split into two main sub-regions: the relatively gas poor Levant (Syria, Lebanon, Iraq, Israel, and Jordan), and the gas-richer countries in the Gulf area (UAE, Qatar, Bahrain, Saudi Arabia, Kuwait, Oman, Yemen, and Iran). In 2016, the Middle East accounted for 14.5 per cent of world gas consumption (512.3 bcm), 18 per cent of world gas production (637.8 bcm), and 42.5 per cent of the world's proved gas reserves of 79.4 trillion cubic metres (tcm) (*BP Statistical Review of World Energy 2017*).

'DEMAND IN THE MIDDLE EAST IS DRIVEN BY POWER, DESALINATION, AND ENERGY INTENSIVE INDUSTRIES.'

Increased demand for gas

In the period 2006–16, the growth in gas consumption in the Middle East averaged 5.63 per cent per year (see figure below), compared to the world's average consumption growth rate of 2.2 per cent. Demand in the Middle East is driven by power, desalination, and energy intensive industries. To put it in context, gas consumption in Iran was nearly equivalent to China's, whereas consumption in Saudi Arabia (KSA) was slightly lower than Japan's (*BP Statistical Review of World Energy 2017*). Overall, according to figures from the US Energy Information Administration, the industrial sector (petrochemicals, fertilizer, and aluminium) accounts for approximately 54 per cent of the region's consumption, followed by power at 32 per cent. Iran is the sole country in the region where gas is widely consumed in the residential sector, which takes approximately 50 per cent of the country's marketed gas production of 202.4 bcma (2016). In addition, according to figures from OPEC, out of Iran's gross production of 257 bcma, nearly 31 bcma is used for reinjection in oil fields.



Middle East: gas demand growth by country

Source: BP Statistical Review of World Energy 2017.

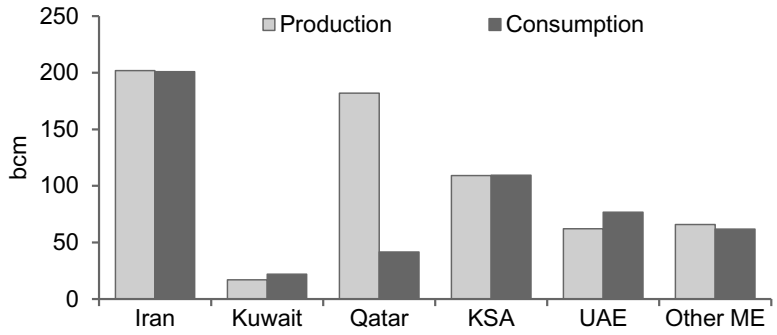
Until the early 2000s the region exported LNG, led by Abu Dhabi, Oman, and Qatar – with Yemen joining the exporting club in 2008 – and there were no imports, except for small volumes imported by Iran from Azerbaijan and Turkmenistan, via pipelines, to meet demand in the north of the country.

The ambitious industrialization projects in the Gulf Cooperation countries called for an increase in gas utilization, which was not supported by domestic production. In the early 2000s, the construction of the Arab Gas pipeline and the Arish–Ashkelon spur line allowed Egypt to export gas to Jordan, Syria, Lebanon, and Israel, whereas the Dolphin Energy 20 bcma pipeline allowed for the supply of gas from Qatar to the UAE (10.4 bcma to Abu Dhabi, 7.6 bcma to Dubai, and 0. 8 bcma to the other emirates) and Oman (2.1 bcma).

In the period 2009–16 gas demand in the Middle East increased by an impressive volume of 153 bcma, but except for Qatar, Iran, and KSA, this was not followed by a substantial increase in domestic production. In addition, due to persistent gas shortages and attacks on the Jordan and Israel pipelines (which started in 2011), Egypt stopped exporting pipeline gas in 2013.

In order to meet growing demand, several Middle Eastern countries embarked on the construction of LNG import terminals: Dubai, Kuwait, Israel, Jordan, and Abu Dhabi, all based their plans on floating regasification schemes (FSRU). Bahrain is joining the LNG importation club, with first cargo expected by 2019.

'… ON A COUNTRY-BY-COUNTRY BASIS, ONLY IRAN, QATAR, AND THE KSA ARE BALANCED OR NET GAS EXPORTERS …'



Middle East: gas production and consumption, 2016

Source: BP Statistical Review of World Energy 2017.

On a regional basis, gas production in 2016 exceeded demand by 126 bcm (*BP Statistical Review of World Energy 2017*), but on a country-by-country basis, only Iran, Qatar, and the KSA are balanced or net gas exporters – as can be seen in the figure above. The remaining countries imported approximately 41 bcma in 2016 (*BP Statistical Review of World Energy 2017*). Although Oman is not currently importing gas, it has started conversations to import from Iran; it has also curtailed further demand growth and rationalized its LNG exports.

According to a report on LNG by the International Gas Union (IGU), in 2016 the Middle East exported 90.9 Mt of LNG (118.2 bcm), and imported 9.5 Mt (12.4 bcm). Abu Dhabi is the most singular case, as it exported 5.6 Mtpa but also commissioned an LNG import terminal (based on FSRU) in Ruwais in 2016 to meet growing power demand, in addition to importing 10 bcma from the Dolphin Energy pipeline.

Taking into account the rich gas resources in the region, its transformation into a growing import hub for pipeline gas and LNG is quite remarkable. Gas reserves in the Middle East have stayed stable at around 80 tcm over the last four years – with the exception of Israel and Bahrain which declined at 13.9 per cent and 5.2 per cent respectively in the period 2015–16.

Prices, actions, and trends

As mentioned previously, a few Middle Eastern countries are constrained by the lack of domestic gas resources – Jordan which, in addition to importing LNG to meet its own demand, is also re-exporting to Egypt via the reversed flow Arab Gas Pipeline, is one example. Others, such as the UAE, have large reserves but use a third of their gross production for oilfield reinjection and process shrinkage, and are still in the early days of developing expensive-to-produce non-associated sour gas.

Growth in gas demand has been fuelled by very low prices for both domestic gas and imported pipeline gas, the latter negotiated when oil prices were in a dip in the early 2000s. It has been reported that the Dolphin Energy pipeline project announced initial prices in the range of US$1.2–1.3/MMBtu to the UAE, whereas Egypt agreed to supply pipeline gas to Jordan and Israel at preferential prices of US$2.0–2.75/MMBtu under deals signed respectively in 2001 and 2005.

According to a 2015 IGU report, gas prices in the Middle East are either regulated below cost for social/political reasons or set up bilaterally by the monopolistic incumbent. These low gas prices reflect the fact that most of the region's gas production is associated gas (with relatively lower gathering and treatment costs), as well as the desire

'… GAS PRICES IN THE MIDDLE EAST ARE EITHER REGULATED BELOW COST FOR SOCIAL/POLITICAL REASONS OR SET UP BILATERALLY BY THE MONOPOLISTIC INCUMBENT.'

of the region's governments to provide a competitive advantage to their gas-intensive exporting industries. Such low gas prices have not encouraged investment in the development of non-associated gas and have also resulted in increased inefficiencies in gas and electricity consumption.

Most economies in the Middle East are heavily dependent on high oil prices to balance their budgets. For instance, according to data from Bloomberg, in 2017, the Middle East OPEC countries need oil prices ranging from US$45/barrel (Kuwait) to US84/barrel (Bahrain) to balance their budgets. The *Times of Oman* states that the Oman budget for 2017 signals a deficit of 30 per cent at predicted oil prices of US$45/barrel; a balanced budget would require oil prices of US$67/barrel in 2017.

In order to adapt to the loss of revenues resulting from the drop in oil prices, governments in the region decided to implement policies to gradually remove price subsidies and rationalize the industry. Following government price hikes in several countries in the period 2015–16, end users' prices currently range from US$1.0–3.0/MMBtu, which is much lower than imported LNG spot prices of US$5.8/MMBtu (June 2017) or breakeven prices for new production, US$1.5–4.5/MMBtu, according to data from the Arab Petroleum Investments Corporation (APICORP) and an IGU seminar on Oman.

- In Oman, the government pushed for the merger of Qalhat and Oman LNG, decreed a moratorium on additional gas supplies to power plants, and increased prices to industrial and power consumers from US$1.5–2.0/MMBtu to US$3.0/MMBtu.
- Saudi Arabia increased methane prices from US$0.75/MMBtu to US$1.25/MMBtu, whereas Bahrain is increasing prices by US$0.25/MMBtu every year until 2021.
- Qatar is also rationalizing its industry – by merging the existing LNG companies, Rasgas and Qatargas – and it has also announced the end of its 10-year gas moratorium with a 20.7 bcma planned increase in production from 2020 (see: 'Qatar lifts its LNG moratorium', Howard Rogers, OIES Energy Comment, April 2017).
- In Iraq there has not been much improvement in gas utilization since the oil bid rounds in 2009, as the country continues to flare large amounts of gas (approximately 14 bcma in 2015, out of a gross production of 23.5 bcma, according to OPEC statistics). The lack of an adequate regulatory framework, together with security issues, have impeded the development of enabling gas infrastructure and much-needed power plants.
- In 2016 Iran imported 6.9 bcm from Azerbaijan and Turkmenistan, due to the lack of gas transportation infrastructure in the north of the country. Iran expects to overtake Qatar's production in the South Pars field by March 2018, which may allow some room for exports, but oil reinjection and the domestic market are their key priorities. In 2015, according to The Iran Project, the government increased the price to households and commercial consumers from US$0.96/MMBtu to US$1.11/MMBtu.
- The UAE have also increased gas and electricity prices as of January zreportedly paying 56–73 per cent more for their electricity. The UAE, Jordan, and Oman are also encouraging investment in renewable energy. According to BP figures, in 2015 the installed wind capacity in the Middle East (excluding Iran) jumped from 157 to 274 MW.

'THERE IS GROWING CONCERN ABOUT THE UAE'S DEPENDENCY ON NATURAL GAS, AS A MATTER OF NATIONAL SECURITY.'

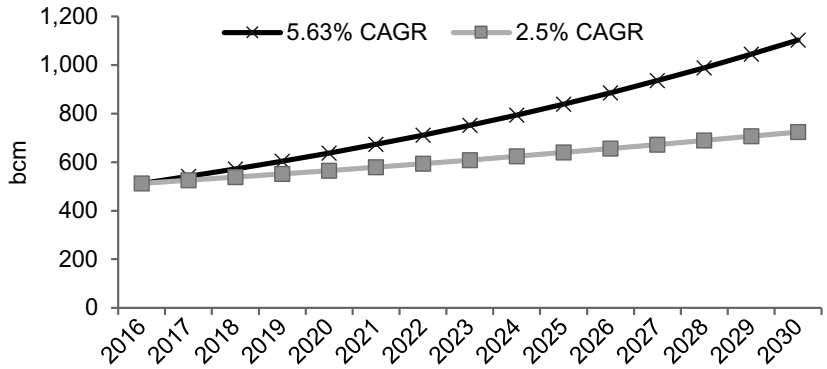
There is growing concern about *the UAE's* dependency on natural gas, as a matter of national security. In January 2017 Sheikh Mohammed bin Rashid Al Maktoum, vice-president and prime minister of the UAE and ruler of Dubai, announced the *UAE Energy Plan 2050*, which aims to increase clean energy utilization by 50 per cent, improve energy efficiency by 40 per cent, and reduce the contribution of natural gas from 90 per cent to 38 per cent. The *Plan* calls for the contribution of clean fossil fuels, nuclear, and renewable energy to be respectively increased to 12 per cent, 6 per cent, and 44 per cent.

Renewable energy is also gaining traction in *Jordan*, as the country imports 97 per cent of its energy needs. Jordan's *National Energy Strategy 2007–20* established a sharp increase in the contribution of renewable energy to the national energy supply. According to the *Strategy*, the share of renewable energy is expected to grow, reaching 10 per cent by 2020. In 2012 the Government enacted the *Renewable Energy and Efficiency Law* which requires the national electricity company (NEPCO) to purchase electricity from renewable energy projects and for the government to cover the cost of grid connection. In addition, the law also provides tax exemptions and incentives on equipment used for renewable energy projects. In 2012, Jordan also introduced ceiling feed-in tariffs for renewable energy projects – ranging from US$85/MWh (biogas) to

US$190/MWh (concentrated solar projects), according to the US export service Export.gov.

In 2015 Jordan commissioned the 117 MW Tafila wind project and is promoting the development of two other wind projects, Fujeij (89 MW) and Al Rajef (86 MW), slated for completion respectively in 2018 and 2019. The projects operate under Build, Own, Operate, and Transfer (BOOT) schemes with the government guaranteeing the purchase of electricity under 20-year PPAs. According to APICORP, the government has also set up a new target for solar PV projects (1000 MW by 2020).

In 2017, according to APICORP, the *Kingdom of Saudi Arabia* (KSA) announced plans to seek investments of up to US$50 billion by 2023 to build up to 10,000 MW of solar and wind projects, backed by 20–25-year PPAs provided by the Ministry of Energy.



Middle East: gas demand projection to 2030

Source: Author, based on BP and EIA data.

Looking ahead for demand growth

If natural gas demand continues to grow at the historic 10-year (2006–16) compound annual growth rate (CAGR) of 5.63 per cent per annum, consumption in the Middle East will increase to 1,103 bcma by 2030, requiring 11.1 tcm of accumulated gas production and imports from other regions. A lower demand growth of 2.5 per cent per annum would see an increase to 724 bcma and require accumulated supplies of 8.7 tcm in the period 2017–30 (see figure above).

Qatar, Iran, and the KSA have been able to add 21 bcma of marketed production in the period 2015–16, but most of Qatar's production is exported to markets outside the Middle East.

'THE RECENT DIPLOMATIC CRISIS, WHERE SEVEN COUNTRIES … SEVERED TIES WITH QATAR MAY HAVE A SIGNIFICANT IMPACT IN THE UAE GAS MARKET.'

The recent diplomatic crisis, where seven countries (Libya, Saudi Arabia, Yemen, Egypt, the UAE, Bahrain, and The Maldives) severed ties with Qatar may have a significant impact in the UAE gas market – and in Oman to a lesser extent because it is served by the same pipeline as that serving Abu Dhabi and Dubai. In 2016 Qatar exported 23.3 bcm to the UAE, Oman, Kuwait, and Jordan (19.8 bcma via the Dolphin pipeline and 3.5 bcm as LNG). Although Qatar could redirect UAE-bound LNG to other markets, the country currently does not have spare liquefaction capacity to accommodate the surplus volumes arising from a potential halt of its pipeline exports to the UAE – at least until 2020, when the expansion of the Ras Laffan LNG complex will be completed. The suspension of pipeline exports would require the UAE (and Oman) to procure replacement volumes of 15 Mtpa from other regions, which in turn would result in a potential boost to LNG prices globally. If the UAE implements an embargo on Qatar pipeline gas and LNG imports, the latter would suffer losses in excess of US$1 billion in export revenues.

In summary, the Middle East has been, until recently, one of the fastest growing gas markets in the world. However, uncertainties relating to geopolitics, a low-price investment-deterring regulatory framework, and the threat of an increased share of nuclear and renewable energy may change the energy landscape significantly over the next five years, with a potential slowdown in gas demand.

MENA: LNG's top growth target

Mustafa Ansari

The MENA region will continue to rely heavily on LNG in 2017 to meet regional power and industry demand. Egypt and Jordan received their first LNG shipments in 2015; Kuwait, the Gulf's first LNG importer, and Bahrain, are looking to construct permanent import terminals; and Abu Dhabi has opted to import LNG via a floating storage and regasification unit (FSRU). Regional LNG importers are seeking to tie up term supply deals, making the most of structural oversupply to lock in favourable pricing and flexibility. It will all make MENA a growing demand-side force in the global LNG sector.

Despite its dominant role in terms of hydrocarbons reserves (47 per cent of global gas reserves according to the *BP Statistical Review of World Energy 2017*), MENA will become the world's second-largest gas-importing region, according to the International Energy Agency (IEA). Consumption of natural gas in the Middle East, the agency forecasts, will rise from 512 billion cubic metres (bcm) in 2016 (*BP Statistical Review of World Energy 2017*) to 804 bcm in 2040 (IEA's *World Energy Outlook 2016* (WEO 2016), p.169). Yet despite its large gas reserves base, production has largely failed to keep pace with evolving demand growth, nor is it likely to do so in the coming years. Absent also is a large regional gas pipeline import network; the potential for LNG to make up some of the balance is therefore strong. LNG imports in the region in 2016 amounted to just 23 bcm, of which 40 per cent arrived from Qatar. But these levels will rise sharply, spurred by the present global supply overhang, which should allow regional buyers to lock in preferential prices and allow them to choose from a wider range of suppliers. Most MENA countries will take a 'wait and see' approach before building expensive permanent LNG-import terminals, wary of a looming tightening in LNG balances and the potential for price increases in the second half of the next decade – although around US$7.6 billion will still be invested by MENA countries in permanent LNG-importing facilities over the next five years, to cater for growing demand. But the advent of FSRUs has changed this picture, especially as many of these are secured on a leased basis, presenting a lower-cost option; they thus break down the barriers to countries becoming LNG importers.

'MENA WILL BECOME THE WORLD'S SECOND-LARGEST GAS-IMPORTING REGION, ACCORDING TO THE INTERNATIONAL ENERGY AGENCY.'

MENA gas demand

Global gas demand has increased by 700 bcm over the past decade, with 70 per cent of this increase coming from Asia Pacific and Middle East countries; according to the WEO 2016 (page 550) gas is expected to be the only fossil fuel whose share in the global energy mix will grow between now and 2040. Within that market segment, LNG's share has been rising for the past ten years, driven by the need to transport gas efficiently over longer distances to a more diverse customer base. Expectations of rising LNG demand from Asian countries have been a key driver for investment in liquefaction capacity.

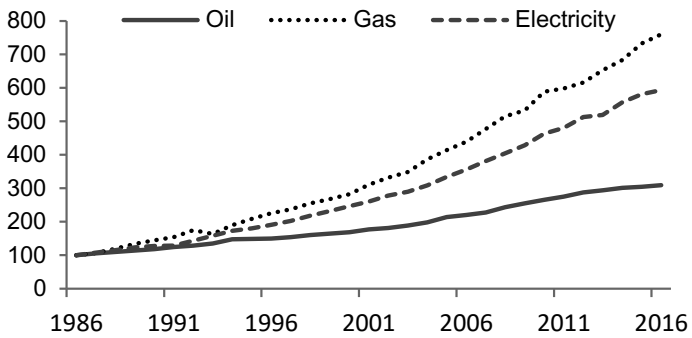
Despite these bullish projections for long-term demand, the short-term picture, at least until 2019, is different, characterized by weaker than expected consumption growth and rising supplies, turning a sellers' market into a buyers' one. With the exception of a modest recovery in the second half of 2016, gas prices have been falling for the past three years – north-east Asian spot prices fell from a little over US$19/MMBtu in 2014 to US$5.52/MMBtu in 2016. Regional prices can also be expected to converge, as the price differential between north-east Asian spot and NBP narrowed to an average of US$0.91/MMBtu in 2016, according to the International Gas Union's *2017 World LNG Report*, (p. 4). This creates an opportunity for MENA importers to benefit from low prices at a time when budgets are tightening.

In the MENA region, demand for gas has grown more quickly than for either oil or electricity over the past three decades (see figure opposite).

- Gas has been prioritized in power generation, which has risen strongly to meet the needs of a growing population whose per capita income levels have also continued to rise.
- Gas-intensive industrialization has been encouraged in MENA countries, partly to capture value and, in the case of oil-producing countries, to help industrialize and diversify their economies. Indeed, petrochemicals and energy-intensive industries have been beneficiaries of policies designed to increase the use of cheap gas.

OPEC countries, in maximizing the use of associated and non-associated gas production in the domestic energy mix, will allow more of their OPEC oil quota to be exported.

The MENA region's reputation as a supplier of global energy obscures a looming domestic supply crunch for natural gas, which will be mostly met by LNG imports. By the end of 2016,



Middle East energy demand growth since 1986 (base 100 in 1986)

Source: BP Statistical Review of World Energy 2017.

countries of the Middle East accounted for 7.9 per cent of global LNG demand – a sharp rise from just under 2 per cent at the end of 2014 (Middle East emerges as LNG demand center, Natural Gas Special Report, Platts March 2017 p. 2).

Qatar aside, the GCC is short of gas

While the Gulf Cooperation Council (GCC)'s per capita gas demand ranks among the highest in the world, its domestic production has mostly failed to keep pace. Most GCC countries have initiated energy-pricing reforms, but the short-term impact on demand is not expected to be significant, at least at current price levels. This means that the onus is on supply-side solutions, notably the securing of LNG imports for the next five years.

Kuwait is a case in point. Domestic production has not kept pace with the rise in gas consumption in the country, a situation exacerbated by the relatively unattractive terms offered to IOCs for development of sour gas and high-cost non-associated gas reserves. So Kuwait was the GCC's first LNG importer (LNG imports amounted to 4.4 bcm in 2016).

'MOST GCC COUNTRIES HAVE INITIATED ENERGY-PRICING REFORMS, BUT THE SHORT-TERM IMPACT ON DEMAND IS NOT EXPECTED TO BE SIGNIFICANT …'

Kuwait also plans to build a permanent LNG-import terminal in Mina Al-Ahmadi. The US$3.3 billion terminal will have a processing capacity of 15 bcma (with the option of expansion to 30 bcma) and is due for completion by 2020.

The UAE is in a slightly different position. It has relatively large reserves of natural gas, but relies on imports to meet peak summer demand. Despite attempts to incorporate renewables in the energy mix and Dubai's commitment to reduce the share of gas in power generation to 70 per cent by 2030, gas demand across the UAE is still expected to rise. Falling oil prices have also hindered the prospects for domestic gas development. Shell, for example, announced its withdrawal from Abu Dhabi's landmark Bab sour gas project in January 2016.

Imports of LNG by the UAE totalled 4 bcm in 2016. Emirates LNG has put on hold plans to install a 12.3 bcma LNG regasification-and-storage facility in Fujairah, and has instead opted to boost imports by chartering an FSRU. Abu Dhabi was the most recent addition to the region's LNG importers, taking delivery of the 138,000 m^3 FSRU *Excelerate* in August 2016 (Dubai began importing LNG in 2014). This option offers a flexible solution to meet power shortfalls, until completion of the UAE's four nuclear reactors in the early 2020s. (The first reactor is expected to come online as early as this year.)

Bahrain produced 19 bcm of gas in 2016, a third of which was used for domestic power generation, as electricity demand almost reached maximum utilization of the country's 4 GW of installed generation capacity. But government plans to expand generation capacity by 1.5 GW, together with a proposal from the aluminium producer Alba to build a 1.8 GW plant by 2019, will require an additional 3.5 bcma of supply. Bahrain's National Oil and Gas Company signed a US$650 million deal with Teekay LNG, Samsung C&T, and Gulf Investment Corp. in December 2015 for the development of an offshore LNG-import terminal, to be commissioned in 2019. The terminal will have a capacity of 4.1 bcma with an option to double this to 8.2 bcma.

Saudi Arabia has the third-largest gas reserves in the Middle East after Iran and Qatar, but has not established itself as a gas producer. All the expected increase in production is committed to power generation and industry. Gas consumption in 2016 reached 109 bcm – a growth of 4.4 per cent on the previous year – meaning that the Kingdom will have to continue producing at an accelerated pace in order to keep up with rising demand. Saudi Arabia has indicated that it is open to LNG imports as part of an effort to displace oil used in electricity generation and raise the share of gas in the generation mix from 50 per cent to 70 per cent by 2030.

North Africa: new LNG importers

Decades of low gas prices in *Egypt* yielded rapid demand growth. Yet domestic output stagnated, and political unrest after 2011 hit investor confidence. Both of Egypt's LNG-export projects, at Idku and Damietta, ran dry of feedstock and the country began importing gas in 2013. It chartered its first FSRU from Norway's Hoegh and a second from

BW Group in 2015. These imports are rising fast: in 2016 they reached 10 bcm compared to 4.1 bcm in 2015. The discovery of the giant 800 bcm Al-Zohr gas field last year, and plans to fast track its development, have raised hopes that LNG imports can be contained. But even if production from new finds reaches full capacity by 2020, domestic gas demand is still expected to outstrip supply by 2 bcma by 2021. A bid to charter a third FSRU in June 2017 (taking total import capacity up to 21 bcma) was postponed last year. A re-evaluation of natural gas projects in the country produced little evidence in favour of higher import requirements in 2017. The Egyptian Natural Gas Holding Company has already signed contracts with suppliers such as Gazprom, Trafigura, and Sonatrach to import up to 15 bcma by 2020. Nevertheless, given the scale of the Zohr field and other recent discoveries, the scale of future Egyptian LNG imports is uncertain. The inevitable move towards more cost-reflective domestic market pricing at some point should also moderate consumption growth.

Morocco produces just 0.06 bcma, and recent exploration efforts have been disappointing, yielding no significant discoveries from the ten wells drilled since 2013. But the Kingdom has been active in reforming its energy sector, and in 2015 phased out all energy subsidies apart from those for LPG. Morocco currently imports 0.6 bcma of pipeline gas from Algeria to feed its power plants, but the construction of two 1200 MW combined-cycle gas plants in Jorf Lasfar and Dhar Doum will mean that the country's gas consumption could rise from 0.9 bcm in 2014 to 3.5 bcma by 2025. The Moroccan utility ONEE selected HSBC Middle East and Ashurst as advisors for the development of the country's LNG-to-power project, estimated to be worth US$4.6 billion. The project includes the construction of an onshore regasification terminal on a Public–Private Partnership basis, enabling Morocco to import up to 5 bcma by 2025. Morocco's reliance on renewables in the power sector makes its future LNG demand difficult to forecast and ONEE plans to purchase 20 per cent of its requirements on the spot market.

Jordan: LNG importer with options

Jordan used to rely on gas supplies from Egypt and Iraq for power generation. Disruptions to Iraqi supplies after 2003 and the collapse of Egypt as a gas exporter prompted the Kingdom to switch some power generation to diesel and fuel oil. At present, gas still accounts for 80 per cent of Jordan's power-generation mix and planned LNG imports should, over time, displace liquids. In May 2015, Jordan began importing LNG after chartering the 7.5 bcma *Golar Eskimo* FSRU for ten years. But the prospect of Israeli gas pipeline imports from 2018 means that Jordan will not expand this LNG-import capacity. Noble Energy, which produces gas in Israel, announced a US$500 million contract to supply 2.2 bcm, spread over 15 years. In September 2016, shareholders in Israel's offshore field Leviathan signed a US$10 billion deal to supply Jordan's Electric Power Co. (Nepco) with 45 bcm over a similar duration, roughly equivalent to the supply it received from Egypt.

Lebanon: delays

LNG would be *Lebanon*'s only gas-import option, after Egyptian gas imports via the Arab Gas Pipeline ended in 2010. In 2013, the government issued a tender to charter a 7.7 bcma FSRU, with imports expected in the region of 1.6 bcm in 2016 rising to 4.8 bcma by 2022. But the lack of progress has pushed plans back towards the end of the decade (if ever) at the very least.

Iraq: missed opportunity

In 2016, *Iraq* produced 27 bcm of natural gas but flared more than 60 per cent of it – volumes that would have been sufficient to power its 15 GW of installed power-generation capacity. Lack of gas-recovery equipment at major oil fields, together with delayed plans for gas gathering and processing by Basra Gas Company, have held up plans to reduce flaring, and forced power companies to burn liquids instead. With 9 GW of gas-fired generation capacity expected to come on line over the next five years, demand for gas is likely to rise steeply over and above existing shortfalls. Permanent import facilities are perhaps a stretch in a country where the government is struggling to sustain public spending, but Iraq could take advantage of low spot prices and follow other neighbouring countries by chartering an FSRU to meet demand shortfalls. There are two pipeline agreements to import gas from Iran, each estimated at around 10 bcma, but security and infrastructure holdups continue to delay imports. Plans for a pipeline to ensure gas recovery in Basra are more likely to materialize than imports over the next five years.

Conclusions

While low LNG prices present opportunities, there are also challenges:

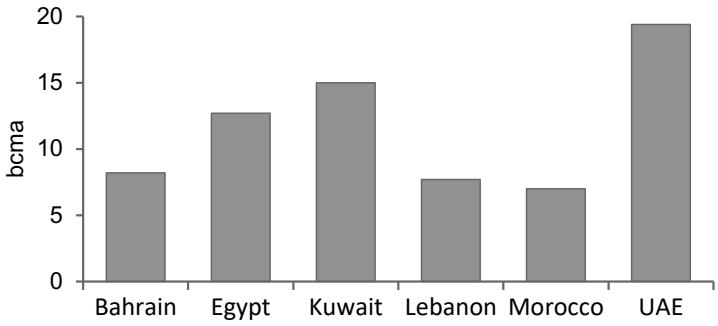
- Creditworthiness continues to fall within the region, raising the cost of finance.
- Lower domestic energy prices reduce the attractiveness of investments in long-term LNG import infrastructure.
- For countries such as Egypt, LNG suppliers are wary of agreeing long-term contracts, given the state's

poor payment history. (Egypt still owes more than US$3 billion to companies involved in its gas sector, despite repaying some arrears.)

- Capital constraints and uncertainties in the LNG market mean that many are opting for FSRUs as a temporary option, taking advantage of low prices before considering more expensive long-term options.

But in the longer term, confronting the gas challenge requires a pragmatic approach to domestic prices for gas (and power) – allowing prices to rise sufficiently to incentivize the development of the region's considerable gas resources. Despite its large reserves, MENA has not deployed sufficient investment to bring these reserves into production, while prospects for regional gas pipeline trade remain limited, due as much to geopolitical uncertainties as underlying project economics.

MENA countries will seek to reinforce gas security by prioritizing gas for the domestic market and by expanding import infrastructure and capacity (see figure above). Low spot LNG prices combined with FSRUs offer a welcome quick fix. Diversified imports in the UAE, Kuwait, and Egypt show that under current market conditions MENA importers can meet seasonal demand peaks. Favourable market conditions should incentivize new MENA importers to do more to ensure that they do not miss the opportunity to install import infrastructure and sign cheap and flexible LNG deals, but the impacts on LNG imports (volume and timescale) are as yet largely uncertain.



MENA planned regasification capacity increase 2017–25

Source: APICORP Research.

'MENA COUNTRIES WILL SEEK TO REINFORCE GAS SECURITY BY PRIORITIZING GAS FOR THE DOMESTIC MARKET AND BY EXPANDING IMPORT INFRASTRUCTURE.'

Natural gas and LNG demand in South American markets

Anouk Honoré

In South America (references to the South American region in this article include: Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Peru, Uruguay, and Venezuela) the production (and commercialization) of natural gas only really started to gather pace in the mid-1990s, apart from Argentina, which started about three decades earlier. Long distances and difficult geography between natural gas reserves and the main population and industrial centres acted as a deterrent to investment in natural gas projects, and in a region relatively well endowed with other energy sources, countries focused on the development of the more profitable oil resources. The regional gas markets remained isolated from other global natural gas markets, focusing instead on achieving self-sufficiency and regional integration, but indigenous production did not develop as fast as consumption, and in order to feed the rapidly growing energy and natural gas demand, the region turned to liquefied natural gas (LNG) in 2008. LNG imports rose rapidly from 0.5 billion cubic metres (bcm) in the first year to 17.2 bcm in 2015. According to the 2016 GIIGNL (the International Group of Liquefied Natural Gas Importers) Annual Report, this represented less than 5 per cent of the total of LNG trades, but it was commonly expected that there would be a continued increase of LNG imports to the continent. However, the trend seems to have turned, and according to the same source, in 2016 LNG imports only amounted to 11.6 bcm or just 3 per cent of global trades. This sudden change, although arguably not unexpected, cast a shadow of uncertainty over future LNG imports. The following paragraphs take a closer look at the characteristics of natural gas demand and LNG import needs in South America in the coming 10 to 15 years.

'… IN ORDER TO FEED THE RAPIDLY GROWING ENERGY AND NATURAL GAS DEMAND, THE REGION TURNED TO LNG IN 2008.'

Large potential for gas demand growth…

The region's total primary energy supply (TPES) is still dominated by oil (44 per cent of the energy mix in 2014) – data for 2014, taken from the IEA's 'World energy balances (edition 2016)', was the most up to date available at the regional level (covering all the countries considered) at the time of writing. This is not surprising considering that several countries are oil producers, including the OPEC members Venezuela and Ecuador. Natural gas is the second-biggest contributor with 21 per cent, followed by biofuels and waste (19 per cent), and hydropower (10 per cent). Coal, nuclear (only present in Argentina and Brazil), and geothermal have only limited roles. The only two exceptions are Colombia and Chile, where coal represents 11 per cent and 19 per cent of the TPES respectively.

The electricity generation mix is dominated by hydropower, which has been the largest source of electricity since the 1970s, typically supplying around 70 per cent of the regional electricity demand. Natural gas is the second most important contributor to the generation mix, far behind, at about 20 per cent. This figure has risen from about 12 per cent in 2000 and 8 per cent in 1990, thanks to the development of the gas industry in the 1990s and the need to add new generation capacity rapidly in order to meet growing electricity demand and provide back up during low availability of large hydro plants. Interestingly, according to the IEA's 'World Energy Balances (edition 2016)', oil products still represent about 8 per cent of the power generation mix. This is a consequence of both rapidly growing power demand and the (still relatively) limited natural gas infrastructure – this factor makes it impossible in certain zones to replace these plants (which have higher generation costs and are more polluting) with natural gas-fired generation.

According to IEA figures, in 2016, the region consumed about 150 bcm of natural gas. The power sector is the largest consumer (39 per cent in 2014), followed by industry (23 per cent), the residential and commercial sectors (11 per cent), transport (6 per cent), and 'other sectors' (21 per cent) which include energy industry own use (using figures from BP and the author's estimates). The main markets were Argentina (50 bcm), Brazil (37 bcm), and Venezuela (36 bcm).

As for energy and power demand, natural gas consumption has grown rapidly since the early 2000s. In 2016, gas demand was 70 per cent higher than in 2000 and 25 per cent higher than in 2010. As the region's economy and population grow, energy demand is expected to continue to increase and become more reliant on natural gas, especially in electricity generation. However, several factors point to a slowdown of gas demand growth.

… but outlook is uncertain

South American countries are very different from one another in terms of land size, geography, resources, energy mix, population, and economy, but one common thread linking all these different countries is the rapid growth of energy demand in the past 20 years or so. Economic growth triggered fast-growing energy and electricity demand and boosted natural gas demand and grid expansion. However, the economic outlook published in April 2017, by the International Monetary Fund (IMF) presented a rather grim picture for future GDP growth in South America as a result of the weakening of key commodity prices. This caused the private sector to lower its spending, which will undoubtedly impact the energy sector and the choices made for future – more limited – investments at least this side of 2020. National measures to improve energy efficiency are also expected to dampen demand growth.

Despite the fact that weaker economic growth will slow down energy demand growth in all sectors, gas demand is still expected to increase. Meeting the needs for both additional generation and providing flexibility will be one of the greatest challenges. However, while the power sector is the largest contributor to gas demand, gas is not the fuel of choice in South America. Most new generation will be in the form of renewables, especially hydropower, but most new hydro will be run-of-river or have small reservoirs especially, but not just, in Brazil. As a result, generation will be even more significantly reduced in dry periods, thus calling for more back-up capacity especially, but not exclusively, gas plants. In the non-power sectors, there is also some potential for more gas penetration in industry and for additional use of compressed natural gas (CNG) in road transport (but if oil prices remain low, such expectations may be over optimistic). There is virtually no need for space heating in the region except in Argentina and Chile, which explains the low expectations in the residential and commercial sectors, despite plans to develop gas distribution infrastructure.

One of the biggest uncertainties relates to the availability of adequate supply (volumes, prices, timing, and flexibility). Supply shortage and/or delay in increasing indigenous production will constrain demand scenarios.

'THE POTENTIAL FOR ADDITIONAL NATURAL GAS PRODUCTION … IS SIGNIFICANT, BUT [IS] FACING CONSIDERABLE UNKNOWNS ON ITS SCALE, LOCATION, AND TIMING'

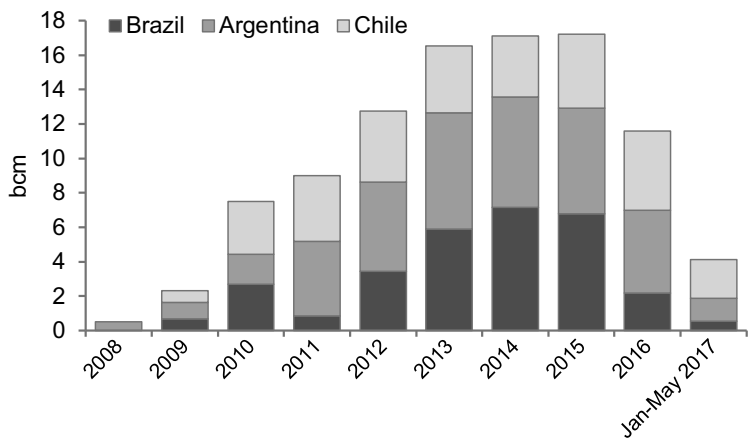
The region has lots of resources and reserves, of both associated and non-associated gas, in conventional and unconventional areas. Natural gas proven reserves have more than tripled since 1980 and this trend is expected to continue – due in particular to the large resources found off the coast in Brazil (presalt basins) and the initial development of unconventional resources in Argentina. The potential for additional natural gas production in South America is significant, but it is also facing considerable unknowns on the scale, location, and timing of the development. LNG imports have been able to provide better security of supply and much-needed flexibility; however, exactly how much LNG will be needed in the future is uncertain.

A disappearing LNG demand?

Argentina, Brazil, and Chile are the main LNG importers (Colombia's first FSRU opened in late 2016, but had not imported LNG after its commissioning cargo, at least by the first quarter of 2017). Argentina and Brazil use LNG to complement indigenous production and Bolivian pipeline imports, while Chile is completely dependent on LNG imports due to a lack of alternative sources for gas supply. As a result, imports to Chile are rather flat throughout the year. In Argentina, they are concentrated during winter months, while in Brazil, they are mostly driven by hydro availability in power generation.

In 2012–15, Brazil faced its worst drought in more than 80 years, with major impacts on the level of hydropower which typically covers about 70–75 per cent of the power generation mix, but over the period of drought this fell to about 60 per cent. All idled thermal power plants were restarted to back up hydropower and address the crisis, boosting natural gas demand and imports of LNG (see figure below).

The sharp decline in LNG demand in 2016 was mainly due to lower Brazilian imports; the country experienced a 12.5 per cent decline of gas demand as better availability of hydropower and rising renewables reduced the need for gas in power generation. One of the three FSRUs, the *Golar Spirit* in Rio de Janeiro state, has been largely idled since April 2016. Lower gas demand due to economic slowdown kept Argentine imports low on an annual basis, while LNG demand in Chile remained high (it is, however, interesting to note that this figure included LNG imports that were re-exported by pipelines to its neighbour Argentina, during winter months when demand increased due to residential heating and its own LNG terminals were saturated). In 2017, it seems that Brazil and Argentina have reduced their needs for LNG due to a combination of weak economic growth and rising domestic production, while Chile has seen the only growth of LNG demand.



LNG imports to South American countries, 2008–17

Source: Platts LNG data.

'THE OVER-RELIANCE ON HYDROPOWER HAS CREATED ECONOMIC LOSSES AND ENERGY SECURITY 'PROBLEMS DURING THE EXTENDED DRY PERIODS …'

One of the major uncertainties about the level of LNG imports to the region comes from the normalization of hydropower generation in Brazil, which should keep the need for gas-fired power plants in the generation mix low, at least for the rest of the 2010s. The level of future gas demand in the power sector will depend on the pace of construction of new gas-fired power plants and their utilization. The over-reliance on hydropower has created economic losses and energy security problems during the extended dry periods when water levels fell significantly. Uncertainties around hydropower generation in Brazil are growing as the new projects are highly concentrated, and any delays in one or two of these projects may cause serious problems. Even if the projects do happen in time, it has become increasingly difficult to build large-reservoir hydroelectric plants, due to stricter environmental regulations and social opposition. New hydro projects will have smaller reservoirs or be run-of-river. This has already changed the shape of hydropower generation, with less storage being available (25 months of storage in hydro plants in 1970, ten months in 1990, five months in 2013, and it is expected to decline to three months in 2023) (see: 'South American gas markets and the role of LNG', Anouk Honoré, OIES

paper NG 114, October 2016). Instead of using hydropower to balance the system, natural gas-fired generation has become an important source of flexibility and security of supply, and it is expected that this trend will continue as hydro generation becomes more volatile. The growth of renewables is also going to contribute to the use of gas plants as backup power.

On the other hand, according to information from Argus, policies designed to attract private sector investment into the electricity sector, such as:

- higher rates charged by hydro and during peaking times,
- wider access to the non-regulated market for smaller suppliers,
- proposed cancellation of supply contracts from polluting thermal plants (fuel oil and diesel) to be replaced with more efficient and less polluting plants,

could increase the role of natural gas in the power mix and, as a result, boost LNG imports especially in the north-east region where reservoirs are depleted by a lack of rain. The Brazilian government is looking at increasing gas-fired generation capacity as a way of securing the power supply and reducing the use of diesel and fuel oil facilities. Integrated projects combining FSRUs and CCGTs are among proposed solutions. New projects have been slow to develop, but the 1.5 GW CCGT in the Sergipe state is expected to come on line in 2020 and will be supplied by LNG imported via the FSRU *Golar Nanook*. The latter is planned for the third quarter of 2018, although it had yet to receive FID at the time of writing (July 2017), according to information from Argus. As a result, gas-fired plant dispatch is expected to gradually increase in Brazil. However, there will be wide differences between wet and dry years. The Brazilian electric energy research company, Empresa de Pesquisa Energética (EPE), for instance, expects that gas for power will be limited to about 10 bcm in 2024 in the case of a wet year, while at the same time it could possibly ramp up to 33 bcm in the case of a dry year. Extending this trend, gas for power demand would oscillate between 9.5 bcma and 43 bcma in 2030.

'THE POSITION OF NATURAL GAS AS A BACKUP OPTION IN POWER GENERATION MEANS THAT FLEXIBLE SUPPLY WILL BE INCREASINGLY NEEDED.'

Conclusions

The position of natural gas as a backup option in power generation means that flexible supply will be increasingly needed. LNG has not been a cheap insurance policy for importing countries, but it will remain necessary to provide the much-needed flexibility that can meet seasonal needs or peak demand in a region with:

- high variations of gas demand from one year to another,
- no storage facilities,
- associated gas production that cannot fluctuate with natural gas demand, and
- long-distance cross-border pipelines that operate on rather flat deliveries (as seen with Bolivian exports to Brazil and Argentina).

However, on an annual basis, this author expects that the region will import only about 7–18 bcma of LNG in 2020 under 'normal' weather conditions – the difference in import figures depends on available Bolivian exports (see: 'South American gas markets and the role of LNG', Anouk Honoré, OIES paper NG 114, October 2016). By 2030, scenarios show a potential of 19.5–30.5 bcma of LNG (still under 'normal' weather conditions) but cold winters in Argentina and dry weather across the region could have significant impacts on LNG imports. In Brazil alone, up to 35 bcma of LNG imports (on top of already needed imports) could be added, in a dry year, by 2030. To conclude, LNG will remain important in South America, but the region is not expected to be a major future LNG market unless there are extreme climatic conditions, which will not happen every year and will not last for many years.

New market entries for gas and LNG

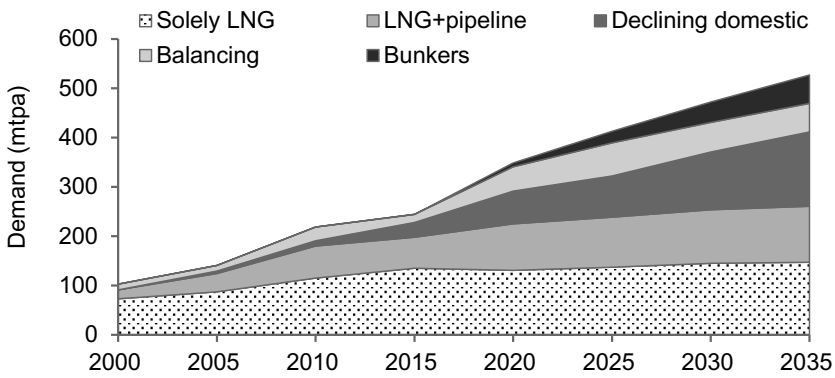
Martin Lambert

Looking back at the history of the natural gas business over the last 25–30 years, the creation of a completely new market for gas has been a relatively rare event. The significant growth of the gas industry has normally come from growth in gas utilization in countries which were already familiar with, and had existing infrastructure for, the product. Of the 70 countries listed as significant gas consumers in the *BP Statistical Review of World Energy 2017*, only Singapore, the Philippines, Vietnam, Hong Kong, Israel, and Portugal were not gas consumers in 1990. Where new gas countries have been created, this has often been driven by the discovery

of significant gas resources which understandably led to a drive to use them to benefit the local economy, for example in Vietnam and the Philippines. Elsewhere, as in Singapore and Hong Kong, the start of gas imports has been driven by a desire to diversify the sources of energy for a combination of security of supply and environmental reasons.

Development of new markets for LNG, on the other hand, has proved a little more successful (the majority of new LNG markets being in countries which were already consumers of natural gas). Between 1990 and 2000, the LNG importing club was remarkably stable at around ten countries, but since then, and particularly in the last ten years with the development of floating storage and regasification units (FSRUs), the number of LNG importing countries has grown to reach 39 (by the end of 2016) according to the GIIGNL 2017 annual report.

In LNG in particular, with the wave of new supply from plants currently under construction (particularly in the USA and Australia), suppliers are hoping that significant new demand will be created to absorb that supply, including from the creation of new LNG markets. One, perhaps optimistic, projection of future demand growth can be seen in the figure above, and in the table below which lists the countries from which it is expected to come (this is similar to a chart on page 14 of the *Shell LNG Outlook*, published in February 2017).



Changing drivers of LNG demand growth

Source: Author's analysis, based on Shell LNG Outlook, February 2017.

This article examines what can be learned from those markets which have already been created, considers some of the barriers to be overcome, and assesses the potential for further new market entries.

Learning from previous development of new markets

The following paragraphs give examples of different approaches to gas market development which have been followed in different countries, to draw lessons for future developments.

'IN BOTH THE PHILIPPINES AND VIETNAM, THE DEVELOPMENT OF A GAS INDUSTRY WAS DRIVEN BY THE DISCOVERY OF SUBSTANTIAL DOMESTIC GAS RESOURCES …'

In both *the Philippines* and *Vietnam*, the development of a gas industry was driven by the discovery of substantial domestic gas resources, which provided an opportunity to diversify the fuel mix, reduce the dependence on imported fuel, and stimulate

Changing drivers of LNG demand growth

Balancing LNG market	North-west Europe		
LNG replaces declining domestic production	India Thailand Indonesia Malaysia	Pakistan* Kuwait UAE Colombia* Egypt*	Bangladesh* Bahrain* Philippines* Vietnam*
LNG complements domestic and pipeline supply	Southern Cone Eastern Europe Southern Europe	North America China Singapore	Morocco* Jordan* Israel
Solely dependent on LNG	Japan Korea Taiwan	Puerto Rico Dominican Republic	Jamaica* Panama*
Bunkers	Atlantic	Middle East	Pacific

* denotes Shell assessment of *emerging LNG importing countries*.

Source: Author's analysis, based on Shell LNG Outlook, February 2017.

wider economic development. In the Philippines, the single Malampaya field, while only around 2.5 trillion cubic feet (70 bcm) (a modest size by global standards), underpinned the development of around 3,000 MW of gas-fired power, which came onstream from 2001 onwards, providing around a third of the country's electricity. Gas consumption ramped up to a little over 3 bcm by 2005 (*BP Statistical Review*) and has been fairly stable around that level since then, with no significant new gas supply infrastructure being constructed. Plans to import LNG have been under discussion since around 2010, primarily to replace the expected decline of Malampaya but also to enable new gas-fired power generation; however, these plans have not yet come to fruition.

In *Vietnam*, large-scale gas development began in 1995 with associated gas from the Bach Ho oil field; additional production from the Nam Con Son gas fields started in 2003 and further fields were added thereafter. As a result, gas consumption has grown steadily from around 2 bcm in 2001 to around 11 bcm in 2016 (*BP Statistical Review, 2017*). Around 80 per cent of gas consumption is used for power generation, with the balance being used for fertilizer and some other small-scale applications. Vietnam has also been developing plans for LNG imports for several years, to complement declining indigenous production and enable additional gas-fired power generation, but it has not yet reached an investment decision.

Singapore, by contrast, has relied entirely on imports for the development of its natural gas market. Imports came initially by pipeline from Malaysia and Indonesia and more recently as LNG through the government-backed onshore LNG terminal. Natural gas consumption grew from around 2 bcm in 2000 to around 12 bcm in 2016, with around 85 per cent of gas being used for power generation (95 per cent of Singapore's total power generation is powered by natural gas).

Jamaica is the most recent gas market to be developed, having imported its first cargo of LNG (using a floating storage unit) in late 2016. A small shuttle tanker supplies a small onshore regasification terminal, which supplies a single 120 MW combined-cycle power plant. The import of gas was driven by a desire to diversify the fuel mix away from an almost complete dependence on imported oil. As in many other countries, it took several years and several false starts before Jamaica was able to succeed as a gas importer. Now that gas is flowing, there are plans to add a further gas-fired power plant and potentially supply some large industrial users. *Malta* is a similar small island market, which has also successfully started LNG imports in the last 12 months, using a floating storage unit to supply a gas-fired power plant of approximately 200 MW.

There are several common themes which can be identified from all of these developments. The development of new gas markets is not straightforward and requires several factors to align for success to be achieved.

- Firstly, there needs to be sufficient creditworthy demand available in order to justify the significant investments in infrastructure: in nearly all cases, this demand has come from power generation.
- Secondly, a strong drive from the country's government to start the gas market has been essential. In many cases, since demand can take several years to grow, gas has not been the most economic short-term solution: government policy is required to drive a strategy which recognizes the longer-term benefits. In some cases, the government has invested directly, but in all cases, there has been a clear policy framework to give the commercial investor, or their financiers, the confidence that the level of risk and associated returns over the life of the project were acceptable.
- Finally, it is clear that there is no standard model for new market development, so it has required skilled commercial structuring to put together a robust value chain; this normally requires several separate but linked investments along the chain. Typically, success requires good co-operation between gas supplier, gas infrastructure developer, power plant developer, power offtaker, and multiple branches of the government.

Potential for further gas market development

An analysis of gas consumption per capita by country (see, for example, Index Mundi's world map of per capita natural gas consumption, which uses *CIA World Factbook* data) shows some interesting trends. A list of those countries which do not have any current natural gas consumption can be seen in the table opposite.

It is notable that many of the countries without gas consumption are among both those with the lowest GDP per capita and those which have often struggled to establish long-term stable government. They are thus missing at least two of the key success criteria mentioned above: sufficient creditworthy demand and stable government.

Thus, the number of potentially realisable new markets for gas is relatively small. For LNG, the table near the start of this article of the changing drivers of LNG demand growth lists the countries which Shell expects to become LNG importers up to 2030. Of those identified

'… MANY OF THE COUNTRIES WITHOUT GAS CONSUMPTION ARE AMONG BOTH THOSE WITH THE LOWEST GDP PER CAPITA …'

Countries with zero natural gas consumption, 2016

Tajikistan	Mauritius	Dominica	Guinea	Rwanda	St Lucia
North Korea	Solomon Islands	Eritrea	Guyana	St Kitts and Nevis	Sudan
Kiribati	Bhutan	Namibia	Haiti	Falkland Islands	Somalia
Laos	Congo	Western Sahara	The Gambia	Comoros	Zambia
Liberia	Burundi	Samoa	Fiji	Cayman Islands	Zimbabwe
Mongolia	Cambodia	Swaziland	Sao Tomé and	Cape Verde	Nepal
Malawi	Chad	El Salvador	Principe	Costa Rica	Nauru
Montenegro	Sri Lanka	Ethiopia	East Timor	Central African	Suriname
Madagascar	Grenada	Tonga	Antigua and	Republic	Nicaragua
Lesotho	Greenland	Togo	Barbuda	New Caledonia	Guinea-Bissau
Kenya	Djibouti	Burkina Faso	Botswana	Niger	Panama
Honduras	Uganda	Sierra Leone	Belize	Bahamas	Paraguay
Iceland	St Vincent and the	Mauritania	Benin	Seychelles	Vanuatu
Mali	Grenadines	Guatemala			

Source: derived from CIA World Factbook.

as '*emerging LNG import countries*': Jamaica, Jordon, Colombia, Egypt, and Pakistan are already importing LNG, while Panama, Bahrain, and Bangladesh have terminals under construction and are expecting to start imports in 2018. That leaves only the Philippines and Vietnam on that list as emerging LNG markets that are still to be developed. Both of these countries have been developing plans to import LNG since around 2010, but they have made slow progress.

Indeed for *Vietnam*, state-owned PV Gas told Reuters in 2010 that an FSRU would be completed by mid-2012, which has proved to be rather optimistic! In 2016, Tokyo Gas formed a joint venture with local partners to develop LNG imports, but there appears to have been little progress since then. With reference to the critical 'success factors' noted earlier, it has proved difficult to develop a creditworthy market willing to pay international LNG prices: domestic gas prices in Vietnam have been relatively low, which has made it difficult for the market to adjust to international prices, and the government has not yet put in place a clear policy framework to provide private investors with an appropriate risk/return balance.

Other potential new gas and LNG markets are in Central America (such as Guatemala, Honduras, El Salvador), but here too plans have been slow to come to fruition. A gas pipeline connecting Mexico to various Central American countries has been proposed for many years (certainly as early as 2000). A report on Mexico News Network in late 2015 suggested that construction would kick off in 2016 and the pipeline would be in operation by 2019, although it did note that the project still faced the challenges of developing:

(a) a regional legislative framework to encourage the necessary investment, and

(b) a commercial structure to allow multinational companies to invest.

To date there appears to have been little further progress on these pipeline plans.

In the meantime, however, in May 2016 *Panama* broke ground on construction of an LNG-to-power project near the entrance to the Panama Canal. This integrated project includes a 350 MW combined-cycle power plant, thereby providing an adequate market for the gas, and the project has been structured so that the private investors (led by US-based AES and supported by a financing package from IFC, a member of the World Bank group) had the confidence to invest in the required infrastructure. It will be interesting to see whether this forms a model for gas and LNG market development which can be replicated in other Central American countries.

'… THE VAST MAJORITY OF NEW GROWTH IN THE GAS INDUSTRY WILL COME FROM ADDITIONAL DEMAND IN COUNTRIES WHICH ARE ALREADY GAS CONSUMERS…'

Conclusion

The history of the gas industry has shown that while it is possible to develop new markets for gas and LNG, favourable outcomes are not easy to achieve, and require many 'success factors' to be in place at the same time. Recent examples in Jamaica, Malta, and Panama demonstrate that with suitable creditworthy demand, typically from power generation, and a supportive government policy framework, it can be possible to create new markets in the current business environment. While it is difficult to make firm predictions, it appears that, as in the past, the vast majority of new growth in the gas industry will come from additional demand in countries which are already gas consumers, rather than from the creation of entirely new markets. For LNG, this leaves open the questions of whether, when, and at what price there will be sufficient demand to absorb the wave of additional supply capacity scheduled to come onstream in the next few years.

Can small LNG meet the challenge of empowering Africa?

Thierry Bros

Africa is one region where energy demand should grow quickly in the coming decades. The remaining question is: what fuel will be used to achieve this economic growth? This article looks at the example of the Ivory Coast, where gas already has a role in the energy mix, and provides an insight on how small LNG could secure gas demand growth in the country. In 2016, a consortium led by the French company Total was awarded the rights to build and operate an LNG regasification terminal in the country. This decision was in line with Total's objective to develop new gas markets and invest down the gas chain in a floating storage and regasification unit (FSRU) on its own merit. This will unlock access to LNG to new markets and help the company relieve some of the pressure from increasing already-contracted supply in the coming years.

The importance of FSRUs in developing markets

On a worldwide level, according to the *World LNG Report 2017*, by the International Gas Union (IGU), FSRUs accounted for 18 per cent of the total number of regas terminals and 11 per cent of the total regas capacity in 2016. They have recently been the most common pathway for new markets (Lithuania in 2014, Egypt, Jordan, Pakistan in 2015, and the UAE in 2016) to access LNG. FSRUs operate mostly in developing markets that have an immediate need for extra LNG before they can find alternative supply (renewables or domestic production). And with requiring a much shorter time to be put in place than regular onshore regasification facilities (around 18 months for an FSRU as opposed to more than five years for an onshore conventional regas facility), the number of FSRUs should continue to grow faster than that of conventional regasification facilities. They can either be owned or rented by the country willing to access LNG – FSRU leasing reduces significantly the capex level of the overall project. Since 2015, these new importers have also been benefiting from lower LNG prices. Even though each of these markets is small, and very different from the more established LNG buyers, FSRUs in aggregate terms (12 per cent in 2016), represented the third-biggest LNG demand after Japan and South Korea (according to GIIGNL – the International Group of Liquefied Natural Gas Importers).

'FSRUs OPERATE MOSTLY IN DEVELOPING MARKETS THAT HAVE AN IMMEDIATE NEED FOR EXTRA LNG BEFORE THEY CAN FIND ALTERNATIVE SUPPLY.'

The gas market in the Ivory Coast

It is estimated that the Ivory Coast produces about 2.5 bcm of gas per year (there are no official up-to-date statistics for the natural gas market in Ivory Coast, this estimate comes from 'La Côte d'Ivoire va doubler sa production de gaz naturel d'ici 2020', a page from the website of LE-GAZ.FR). About 90 per cent of the indigenous production is used in the power sector – this information was provided by the representative of the Ivory Coast Energy Ministry at the Africa Energy Forum on 8 June 2017 in Copenhagen (the data on the ministry website is not up to date). The country has 2,000 MW of installed power generation capacity, of which two-thirds is thermal and rest is mostly hydro.

With gas demand growing faster than indigenous production, the government had to find a solution to rebalance the rapidly growing gap. In October 2016, the CI-GNL (Ivory Coast LNG) consortium, led by Total, was awarded the rights to build and operate a 3 mtpa regasification terminal (according to the Total press release, 'Ivory Coast: Total becomes the operator of the LNG terminal project', 25 November 2016). This decision, announced by the Government of the Ivory Coast, was followed by signature of the shareholders' agreement between Total (which will operate the project with a 34 per cent interest), the national companies PetroCI (11 per cent) and CI-Energies (5 per cent), as well as SOCAR (26 per cent), Shell (13 per cent), Golar (6 per cent), and Endeavor Energy (5 per cent).

Each company expects to use the terminal to import LNG to meet the national demand and the project is expected to be operational by mid-2018. It involves the construction of an FSRU in Vridi in the Abidjan area and a pipeline which will connect the FSRU to the existing (and planned) power plants in Abidjan. Initially the gas will be bought by CI-Energies (the state power company) to supply the existing gas power plant as well as the two future power plants. These gas-fired power plants will be the main consumers of imported LNG. Contrary to the position in other sub-Saharan countries, the credibility of the Ivory Coast government and the history of gas and power in this country (gas-fired power plants have been operating in the Ivory Coast since 1994, with four plants now in operation) gives the necessary comfort for Total to invest in this project. Total believes this 'anchor customer' is sufficiently large and reliable for

this investment case. According to information from Total, the total cost of the project is around US$150 million and includes a leased FSRU terminal.

Economic size of FSRU projects

As seen with this example, the traditional model of large economies of scale – where it was the case that 'the bigger, the better and the cheaper' on a unit basis – is not so true anymore. The capex of small FSRUs and small power plants has decreased in the last few years, providing a greater opportunity to meet (initially) small pockets of gas demand. Modern FSRU solutions offer the quickest, most cost efficient, and flexible way of importing LNG to Africa.

'MODERN FSRU SOLUTIONS OFFER THE QUICKEST, MOST COST EFFICIENT, AND FLEXIBLE WAY OF IMPORTING LNG TO AFRICA.'

FLNG import terminals could further transform the reliability and competitiveness of the power generation and gas markets, as expressed by Golar's business idea which is '*to monetise stranded gas assets that can currently be acquired at 0.1 to 0.2$/MMBtu and develop them into power using Floating Liquefied Natural Gas (FLNGs), LNG carriers, FSRUs and combined cycle gas turbines (CCGTs) thereby giving consumers cheaper, cleaner and more flexible energy*' (slide 14 of Q3 2016 Golar presentation). This could provide '*gas at 40$/MWh while average electricity price is 120$/MWh in Africa*'. In addition, the optionality embedded in floating regas also reduces the suppliers' risks because if bills are unpaid, the regas terminal will be relocated; and if bills are paid, this will prove that new demand can be met. Investors may see FSRUs as an illiquid asset that can be relocated to serve another customer if the initial business model fails: LNG is not only better for the climate than oil products, but its use also reduces the risk of theft that can happen when a dedicated infrastructure is needed.

Gas pricing and future demand in the Ivory Coast

The innovation in the Ivory Coast is to try, with a 20-year contract underpinning the project, to find an acceptable pricing level at the beginning of the project life (when the regas is not in full use due to the ramp up period of the gas-fired power plants), without compromising the shareholders' return (if prices are too high, this would deter demand growth). However, pricing mechanisms can evolve once the market is established and demand starts to grow. For example, if the project delivers LNG to industrial and power sites and displaces the petroleum products originally used, an oil-indexed price could even be envisaged. In the longer term, the government has an 11 per cent renewables target for 2030, but this shouldn't negatively impact gas demand as the demand growth should be high in the coming years.

LNG portfolio players would need to step in and invest in not only the LNG receiving terminal infrastructure, but also potentially in pipelines and power plants to provide energy to industries and end-user consumers. Once this infrastructure is built and partially amortized, LNG will be in a position to maintain its role in the mix and even, potentially, to serve more consumers, which would create further new demand in these markets, growing the LNG market globally. The relative cost of investing in the downstream market is small compared to the cost of the whole LNG chain (where the upstream alone ranges above US$10 billion), and it helps to diversify the seller's risks. Total decided to invest in the power market and sell electrons (electricity) rather than stick to its usual position of 'selling the gas molecule'. This creates new risks for the company but allows a better alignment of interests between all stakeholders and provides a quick solution to increase power generation in the Ivory Coast.

'FSRUs AND GAS-FIRED POWER PLANTS ALLOW COMPANIES TO TEST A MARKET AND TO SCALE UP IF SUCCESSFUL (OR TO LEAVE IT IF UNSUCCESSFUL).'

Conclusion

FSRUs and gas-fired power plants allow companies to test a market and to scale up if successful (or to leave it if unsuccessful). Additional demand is still more likely to occur in markets that already consume gas, rather than in markets where gas is not present in the mix. Where there is currently no gas market at all, the development of such a market will obviously be more challenging because of the infrastructure that will need to be developed. Private companies will need help from international agencies to kick start an FSRU project. The cost of gas and the creditworthiness of African clients (most sub-Saharan African countries have poor sovereign credit ratings, which severely limits their capacity to borrow from the global capital market) may complicate the development of such projects, as expensive gas is not an option in Africa. With high gas or LNG prices, demand will not develop and/or will be replaced by another petroleum fuel, coal, or renewables. This is where timing becomes a real challenge. An FSRU only takes about 18 months to be connected. If a project starts this side of 2020, the new markets could benefit from low LNG prices as the market should remain long until the middle of the 2020s. But if the decision-making process takes years, then the FSRU might start operation at a time when the LNG market tightens and prices rise, and therefore any opportunity to develop new markets for LNG in many countries of Africa would be lost.

The demand for gas as a transport fuel

Chris LeFevre

The use of natural gas as a transport fuel was last covered in the context of LNG as a fuel in the shipping and road transport sectors (*Oxford Energy Forum*, August 2016, Issue 106). Since that time, the level of interest has grown, and scarcely a day goes by without an announcement of new investments in shipping or refuelling facilities or the conclusion of a cooperation agreement between players in the market.

'THE MOST PROSPECTIVE MARKET IS IN THE USE OF LNG AS A MARINE FUEL …'

This article assesses how this increase in interest and activity might translate into concrete demand over the next decade. The most prospective market is in the use of LNG as a marine fuel, where its potential cost and environmental advantages make it a practical alternative fuel to heavy fuel oil or marine diesel. Natural gas (both CNG and LNG) could make inroads into the road transport market (heavy goods vehicles in particular) but because of the relatively small impact in gas demand terms, the focus is primarily on the marine sector.

The main drivers

There are both 'demand pull' and 'supply push' factors. From a *demand perspective*, the attractions of LNG arise primarily from its environmental advantages in comparison to alternative marine fuels – heavy fuel oil (HFO) or marine gasoil (MGO). LNG typically produces lower emissions of carbon dioxide (CO_2) and virtually no nitrogen oxides (NO_x), particulate matter (PM), or sulphur oxides (SO_x).

This environmental benefit is of importance given the restrictions on fuel oil consumption introduced by the International Maritime Organization (IMO) under the so-called MARPOL arrangements. At present, these take the form of limits of 0.1 per cent sulphur in fuel oil in the mandated emission control areas in North America and Europe (introduced in January 2015). Separately, the Chinese authorities have been introducing 0.5 per cent sulphur limits in ports throughout the country. In October 2016, the IMO set 2020 as the year of implementation of a 0.5 per cent cap – the present limit is 3.5 per cent – on sulphur content in marine fuels worldwide.

The environmental impact of marine transport has also received more attention in the context of growing concerns over the health impacts of NO_x and PM emanating from oil-based fuels in and around ports in major cities.

LNG is an attractive alternative and this is enhanced by several *supply side* factors. These supply side factors include the increased availability of LNG and LNG terminals (many of which have spare capacity) and the presence in some markets, such as Spain, of an existing off-grid sector supplied by LNG. LNG is not, however, the only option available to ship owners and operators.

Options for ship owners

Given the pressing need to respond to existing or imminent restrictions on fuel oil, compliant ship owners can pursue several options:

- Switch fuels to either low (0.5 per cent) sulphur fuel oil or marine gasoil;
- Install scrubbers to remove sulphur;
- Switch to LNG.

The cost of switching to LNG on an existing ship is likely to be prohibitive, so in the short term most ship owners are likely to switch to lower-sulphur fuels or install scrubbers. The latter option is estimated to cost around US$6 million and take one month to complete.

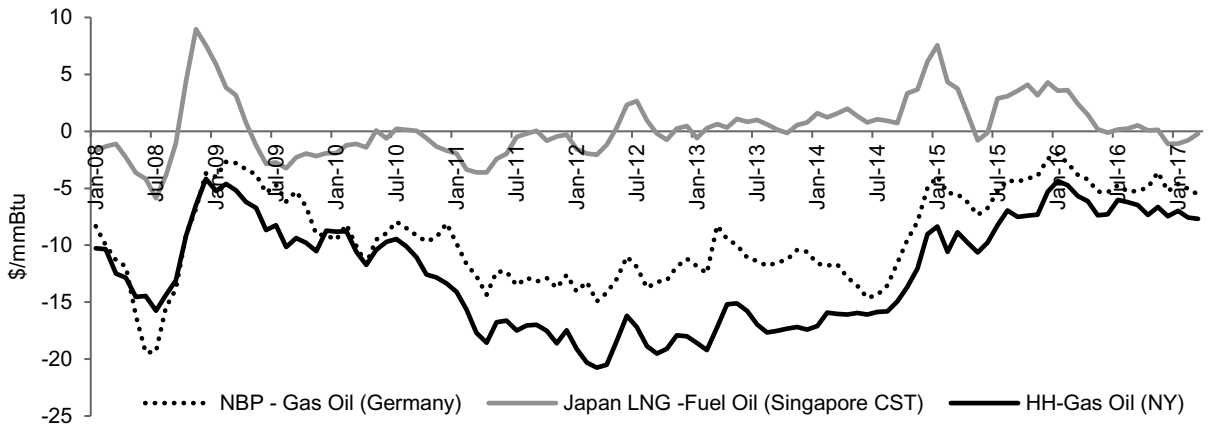
A decision to opt for LNG is therefore likely to be taken at the time of deciding to build or purchase a new ship. A decision will consider the following factors:

- Comparative fuel prices;
- The cost and availability of appropriate vessels and refuelling infrastructure;
- Commercial and regulatory frameworks.

Comparative fuel prices

Fuel costs are a critical consideration for any ship operator and can account for 60–80 per cent of a vessel's operating expenses. The commodity price of LNG has been well below that of oil products in non-Asian markets for many years, though the gap has decreased since 2015 with the fall in oil prices. This narrowing of differentials is illustrated in the figure opposite, which shows the differential with gasoil in the emission control areas of North America and Europe and with fuel oil in Asian markets. The figure also shows that natural gas has generally been cheaper than gasoil in Europe and the USA, whereas the differential between

'FUEL COSTS ARE A CRITICAL CONSIDERATION FOR ANY SHIP OPERATOR AND CAN ACCOUNT FOR 60–80 PER CENT OF A VESSEL'S OPERATING EXPENSES.'



Marine fuel price differentials with regional gas prices

Note: negative differential means gas is cheaper.

Source: Argus data.

LNG and fuel oil in Japan is generally narrower, which is to be expected given that the price of most Japanese LNG is still linked to crude oil prices. Asian gasoil prices are typically 50 per cent higher than fuel oil prices.

The actual price paid by LNG marine fuel users will depend on factors such as point of delivery and other contractual terms. Furthermore, the present pricing differentials do not reflect the way in which the oil products market might adapt as demand switches from high-sulphur fuel oil to other products. Significant refinery configurations are likely to be required and it remains to be seen how this will impact prices. Nevertheless, LNG is likely to continue to offer lower fuel costs for ship owners in most markets.

Cost and availability of appropriate vessels and refuelling infrastructure

The attractiveness of this benefit must be weighed against the higher capital charges for a new LNG-fuelled vessel. These relate primarily to the higher costs of an LNG-fuelled engine and of the storage and delivery system. Studies suggest that a discount of US$2–4/MMBtu to the equivalent fuel is required for most vessel types, while very large bulk carriers require a discount of around US$6/MMBtu. The figure above shows that differentials with gas oil have been at least US$5/MMBtu for most of the time since 2008.

Ship owners also need to consider the availability of LNG refuelling infrastructure. LNG terminal operators have recognized the advantages of offering a wider range of services than simple storage and regasification. These new services include:

- transferring LNG to smaller tankers,
- bunkering vessels and road vehicles, and
- the establishment of small-scale storage facilities.

Europe has made the most progress in this area, and reloading capacity had reached nearly 5 bcm by the end of 2016. This capability was available at terminals in France, Spain, the Netherlands, Belgium, and the UK. Elsewhere, marine-based facilities are either established or being developed in the USA and China. China also has an extensive LNG refuelling network for road vehicles.

Commercial and regulatory frameworks

Ship owners usually charter their vessels to operators under long-term contracts. The owners do not, therefore, reap the fuel cost savings associated with the higher investment cost. This makes retrofitting a vessel for LNG particularly challenging. There is also regulatory inconsistency between (and sometimes within) countries regarding the licensing and control of LNG re-fuelling. Operators and users have stressed the importance of harmonizing standards and operations across all prospective markets.

'LNG SHIPPING IS PARTICULARLY SUITED FOR FERRY TRAFFIC, CRUISE SHIPS, AND COASTAL LINER OPERATIONS.'

The factors described above make retrofitting to use LNG highly unlikely and so the decision will normally be taken at the point of vessel renewal. LNG is particularly favoured where:

- usage patterns are predictable,
- re-fuelling facilities are readily accessible, and
- there is strong environmental pressure to adopt the cleanest fuel available.

This means that LNG shipping is particularly suited for ferry traffic, cruise ships, and coastal liner operations. To provide flexibility, ship owners may opt

for 'LNG-ready' ships that can also use gasoil.

Quantifying the demand prospects

There is no doubt that the market for LNG in transport is going to grow. The critical questions are: how quickly and to what extent will this growth take place and are there likely to be any significant regional variations in the market profiles?

Before attempting to answer these questions, it is important to remember that this market is still at a very early stage and, as we have seen, there is a wide range of factors that are likely to shape its future development. Furthermore, data availability is patchy and there are no reliable figures for global LNG usage in the transport sector. Where gas in transport is recorded, LNG is often grouped with CNG and other fuel sources including LPG. Any estimates are therefore subject to significant degrees of uncertainty.

How quickly and how far?

The following examples can be used to try and scale the prospects:

- In Norway, which has been a pioneer in developing LNG as a marine fuel, there were, according to DNV, 77 LNG-fuelled vessels in operation in 2016. Norwegian government statistics show that LNG consumption in shipping in 2015 was around 0.15 bcm.
- Carnival Cruise lines has seven LNG-fuelled cruise ships on order, with delivery dates between 2020 and 2022. When operational, these will have a combined annual LNG fuel requirement of 0.3 bcm. The company has a total annual fuel usage of 32 million tonnes, so it alone could represent a very significant market for LNG, although given the age of its fleet, it may take 20 years to develop fully.
- China has the largest LNG-fuelled road fleet in the world and, according to Shell, LNG in transport demand in 2015 was around 5 bcm.
- In the USA, the EIA reports that natural gas usage in vehicles, trains, and ships was around 1.5 bcm in 2015 and this is forecast to grow to 4.5 bcm by 2025.

Forecasts from a wide range of sources put demand for LNG in marine transport in the range of 8 to 20 million tonnes by 2025, which represents between 2 and 5 per cent of the global marine fuels market in 2025. Based on the foregoing, the lower end of this range is more likely with perhaps 15–30 bcm demand by 2030. Road transport demand could add another 10 bcm, though this may not all be sourced from the international LNG market.

Regional variations?

Turning to the regional dimension, the prospects are greatest in the three major markets of North America, Europe, and China. These markets share some common characteristics including large long-haul road freight and coastal/inland shipping sectors, together with existing LNG infrastructure.

China has a well-developed inland LNG supply chain and, as indicated above, LNG is used significantly as a road vehicle fuel. The country has the largest LNG-fuelled fleet in the world – in 2016 there were more than 200,000 LNG-powered vehicles, representing around 2 per cent of the heavy duty vehicle fleet. Restrictions on fuel oil have already been introduced in several coastal and inland locations.

The North American market has the additional advantage of low-cost indigenous gas production and an innovative LNG vehicle and engine sector with several players. The use of LNG in shipping and road vehicles is still, however, at a very early stage. Total natural gas consumption in land transport was around 1 bcm in 2016.

'DEVELOPMENTS IN THE MARITIME SECTOR … COULD PROVIDE A PLATFORM OF SIGNIFICANT SCALE TO ALLOW ROAD-BASED USAGE TO DEVELOP …'

In Europe, the role of Norway has already been noted and a broad-based LNG bunkering market is emerging in the Baltic and North Sea. The EU Alternative Fuel Infrastructure Directive and the LNG Blue Corridors project are also encouraging the use of LNG, although take-up is still relatively slow.

Conclusions

LNG as a marine fuel presents a viable alternative to owners and operators that has both financial and environmental advantages. It is not the only option available, however, and is only likely to be adopted at the point of vessel renewal. Vessels such as ferries, cruise ships, and those engaged in coastal liner operations are particularly suitable for LNG and the supply infrastructure is developing rapidly.

Developments in the maritime sector are likely to be key and this could provide a platform of significant scale to allow road-based usage to develop in a relatively risk-free environment.

The oil/gas price spread has narrowed since 2015 although LNG prices look likely to remain competitive with existing fuels for some time. As refiners adapt to the restrictions on fuel oil, however, this dynamic may change by 2020.

Taking account of these factors, and given the present sluggish state of the shipping sector where vessel oversupply is still evident, the pace of growth in demand is most likely to be at the lower end of forecast ranges. It is still too early to determine how large the market might be.

Coal-to-gas switching: air pollution rather than carbon may be the key catalyst

James Henderson

Gas has consistently marketed itself as the 'clean' hydrocarbon, and numerous studies have shown how its use could reduce carbon emissions if it were to replace coal in the energy mix.

Gas priced out by falling coal prices

The particular focus has been on the power sector, where the switch is most obvious, but the key problem has been that economic reality has continued to favour coal (as environmental considerations have put pressure on coal demand, an oversupply of the fuel has arisen and prices have fallen). The result has been that in many countries power producers have continued to use coal as both the baseload generation fuel and to provide the essential balancing role for the intermittency of increasing renewables capacity, with gas being priced out of the market. This was especially true during the period 2010–14, when gas prices were driven up by an oil price that was over US$100 per barrel, but it has remained the case in many regions since then as the subsequent fall in the gas price has been more than matched by a decline in coal prices.

'… IN MANY COUNTRIES POWER PRODUCERS HAVE CONTINUED TO USE COAL … WITH GAS BEING PRICED OUT OF THE MARKET.'

As a result, the motivation to reduce carbon emissions, which was re-emphasized at the COP21 meeting in Paris in 2015, has not always been strong enough to counter the commercial incentive to use the cheapest source of fuel for power generation and in various industrial sectors. Furthermore, concerns over security of supply, local employment, and domestic politics have also played a key role in sustaining the role of coal versus gas.

A key question for the future, then, is whether the gas industry will be able to persuade policy makers and consumers that the benefits of gas deserve a premium price, or whether gas can only flourish if it can compete with coal on price. In other words, will governments use policy to compensate for the higher CO_2 and particulate pollution 'externalities' of coal which are not reflected in its price?

Coal-to-gas switching in the USA

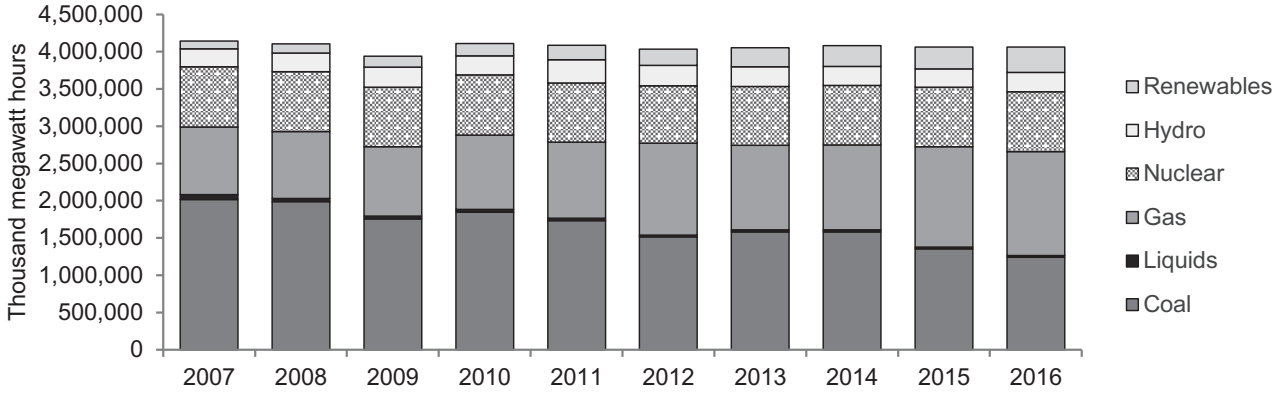
The USA is often cited as a country where coal-to-gas switching has been an unqualified success, driven by the emergence of shale gas and the consequent fall in domestic prices. As can be seen in the figure below showing the fuel mix in the US power sector, it is undoubtedly the case that over the past decade, the contributions of coal and gas in the power generation mix have switched places. In 2006 coal accounted for 49 per cent of total US power output while gas only accounted for 22 per cent, but by 2016 the share of coal had fallen to 31 per cent while gas had overtaken it for the first time to reach 34 per cent.

The key catalyst for this shift has been the *dramatic fall in the domestic gas price* which, over the decade, has declined from over US$12/MMBtu to a low of below US$2/MMBtu, while it currently stands at around US$3/MMBtu (according to the Energy Intelligence Group, the average price for the first three weeks of July 2017 was US$2.97/MMBtu). However, while

'… THE POWER GENERATION MIX IN THE USA REMAINS VERY SENSITIVE TO PRICE …'

this has provided a major incentive, the power generation mix in the USA remains very sensitive to price, and it is interesting to note that in March 2017 a small shift in the relative prices led to a rebound in coal demand and a decline in gas, underlining the competition that still exists between fossil fuels.

However, although price has been a key factor, it is important to note that even in the USA's highly competitive environment *social and political drivers*, such as the employment impact on the coal and gas industries, also have an important role. From a policy perspective, the Clean Power Plan, which addressed a broad range of environmental issues (it was introduced in 2015 but was then challenged in the Supreme Court in 2016), will have a huge bearing on the future energy mix, with the EIA painting very different pictures in its latest Annual Energy Outlook depending on its implementation. For example, according to 'Projected electricity generation mix is sensitive to policies, natural gas prices' (US EIA, February 2017) full implementation would see the share of coal fall significantly below those of gas and renewables by the end of the next decade, while conversely if the plan is rejected then coal could quickly recover its position as the largest fuel input to power generation and retain it well into the 2030s. The outcome could well depend on the policies adopted by the Trump administration, which has recently withdrawn from the COP21 agreement



The fuel mix in the US power sector, 2007–16

Source: US Energy Intelligence Agency.

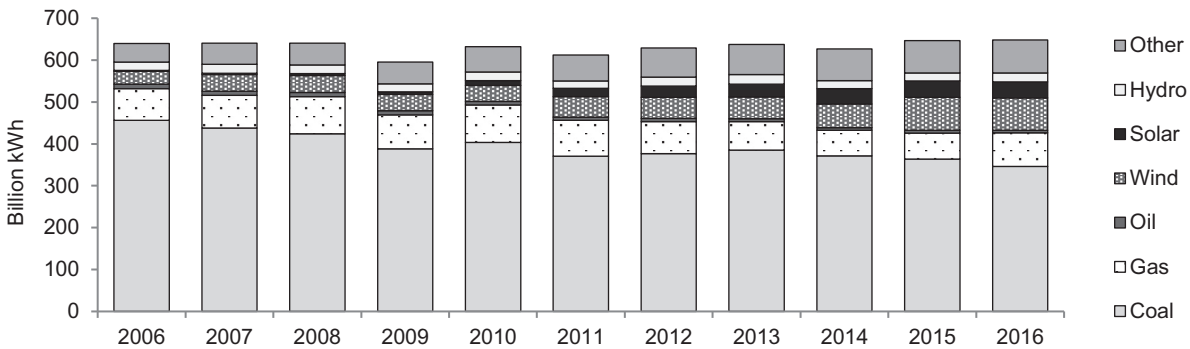
and which has promised to support the domestic coal industry. If this results in a reduction in low carbon initiatives and a rejection of plans to reduce coal-fired generation, then the positive trends for gas seen over the past decade could be dramatically slowed, if not halted.

The changing power generation mix in Europe

In Europe gas is also facing a challenge as it attempts to maintain a long-term role in the energy mix, in particular in competition with other fossil fuels. Despite the best intentions of the EU and its member countries to reduce carbon emissions in accordance with their COP21 commitments, the issue of price is even more relevant in Europe where gas has been, and to an extent remains, a premium-priced fuel. As a result, greater policy support for a switch from coal to gas is a necessity if the latter is to have a strong future, as can be seen from a number of examples across the region.

In *Germany*, for example, which has been the strongest proponent of renewables development, coal (and lignite) have remained the main fossil fuels in the energy mix as gas has been displaced by solar and wind, with the result, according to the *BP Statistical Review of World Energy 2016*, that German CO_2 emissions were at the same level in 2015 as they were in 2009. This outcome was driven by the low cost of imported coal, the employment implications for Germany's domestic mining industry, and gas security of supply concerns which have argued against moves to disadvantage Germany's indigenous coal production. However, it is interesting to note that in 2016 there was a significant rebound in gas demand (see figure below), driven by low gas prices during the year and a sharp rise in the coal price in the second half, suggesting once again that when gas can compete on price it will displace coal even when social and political factors are in play.

'… WHEN GAS CAN COMPETE ON PRICE IT WILL DISPLACE COAL EVEN WHEN SOCIAL AND POLITICAL FACTORS ARE IN PLAY.'



German power generation mix by fuel, 2006–16

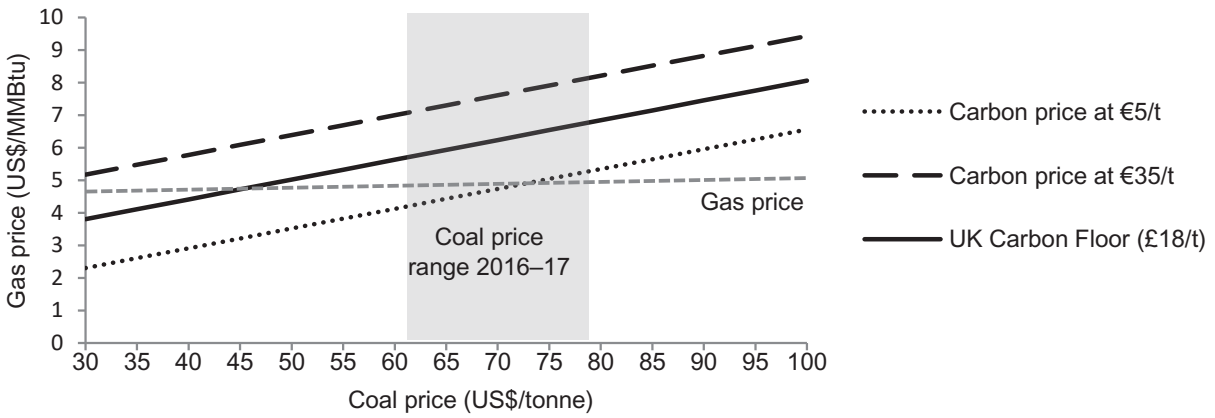
Source: AG Energiebilanzen.

The potential impact of price and policy can be seen most clearly in the example of *the UK*, where the government took a decision in 2013 to introduce a 'carbon floor price' to supplement the low carbon price set at the EU ETS in Europe. While highlighting a key issue for gas in Europe (namely the lack of a sufficiently high carbon price), it also clearly demonstrated what could happen if a carbon incentive is provided. With a floor price of £18 per tonne (around €21 per tonne), coal was completely removed from the power generation mix at some points in 2016 (also helped by the narrowing gap between coal and gas prices). Indeed the figure below underlines the impact of the UK carbon price, showing the switching point between gas and coal at various carbon, gas, and coal prices. The solid line shows the switching price between coal and gas, assuming the UK carbon price, and when this is compared with the current European gas price of US$5/MMBtu it is clear that generators are incentivized to switch away from coal at any coal price down to US$40–45 per tonne (the current price is around US$78 per tonne, and the range of prices over the past 18 months is shown in the grey area). In contrast, the lower (dotted) line shows the switching price at the current EU ETS carbon price of €5 per tonne, indicating that at a gas price of US$5/MMBtu, switching would take place at a coal price of around US$70 per tonne. Meanwhile, the higher (dashed) line shows the impact of a potential carbon price of €35 per tonne, which would allow switching to take place at a coal price as low as US$30 per tonne, which is generally regarded as the average short-run marginal cost of coal imports to Europe. As a result, it is the ultimate goal for policy makers keen to see a complete shift away from coal.

The current balance of coal, gas, and carbon prices looks reasonably promising (given the current coal price of US$78 per tonne mentioned above), although in Europe any downward movement in coal prices would cause a rapid switch back away from gas.

In addition, increasing levels of policy support are being seen at EU and country level, with the impact of the Large Combustible Plant Directive, the Industrial Emissions Directive, and individual country plans to limit coal-fired generation all providing a positive outlook for gas. However, it is also clear that the future of coal-to-gas switching needs to be considered on a country-by-country basis, and will be particularly relevant in countries that have spare gas generating capacity available for immediate use. By contrast, in countries with a predominance of coal and concerns over gas security of supply, the incentive to switch is much lower. The most often cited example of this trend is *Poland*, which is keen to continue exploiting its indigenous coal resources and to avoid reliance on Russian gas, another theme that is undermining support for gas in many central and eastern European countries that wish to reduce potential influence from the Kremlin.

A more recent and dramatic example is *Turkey*, where the government has completely changed its policy towards gas in the past 12 months, now preferring to support a mix of coal and renewable energy. Concerns over excessive reliance on gas imports (especially from Russia) as well as a desire to use local coal that is cheap and provides employment are again the key drivers.



The switching price from coal to gas in the UK and Europe

Note: Assumes a coal plant with 38 per cent efficiency and a gas plant with 55 per cent efficiency.

Source: Author's analysis.

'THE PRICE DIFFERENTIAL BETWEEN COAL AND GAS IS A KEY DRIVER OF FUEL SWITCHING, WHICH CAN BE ENHANCED OR UNDERMINED BY GOVERNMENT POLICY …'

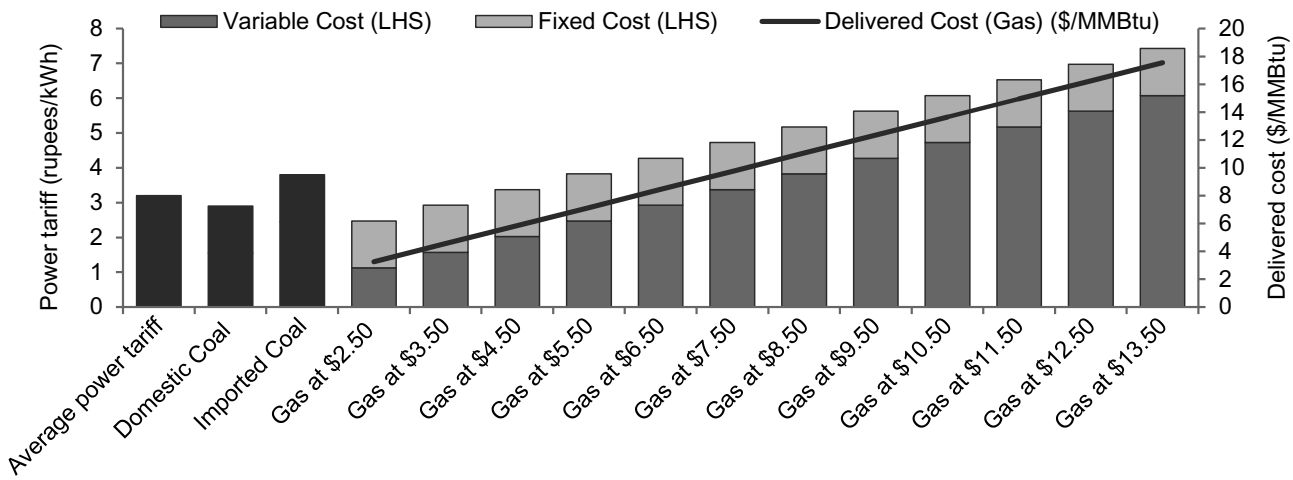
The trend from the USA and Europe is therefore clear. The price differential between coal and gas is a key driver of fuel switching which can be enhanced or undermined by government policy, either by the introduction of extra incentives to encourage gas use (a carbon price) or by a shift in policy caused by a focus on key domestic issues (meeting carbon targets – good for gas – or concerns over security of supply and domestic industry – normally good for coal).

Diversifying the energy mix in Asia

If one then extrapolates these themes to Asia – a region with huge potential for gas demand growth if coal consumption is constrained by policy or prices, but also with huge coal resources – it would seem sensible to consider whether similar logic to that seen above will apply. *China* and *India* both have energy economies dominated by coal, but the governments of both, nevertheless, have significant ambitions to expand the role of gas, mainly for the purpose of improving air quality but also with the more general goal of diversifying the energy mix.

However, the economics of this switch are not helped by low coal prices and the perception (and indeed reality) that gas continues to be an expensive alternative. The position in *India* is clearly illustrated in the figure below, which shows the price at which gas needs to be delivered to an Indian power generator to compete with domestic and imported coal. Essentially, if the gas price is above US$4.55/MMBtu then coal-fired power is cheaper. This situation could be mitigated by government policy of course, but other than grand plans for increased gas demand, there is little in the way of specific policy to suggest that a target of tripling the share of gas in five years will be met, not least because of a confused pricing strategy that provides no incentives to domestic producers and continues to provide significant subsidies for certain consumers.

A similar concern exists in *China*. Gas demand expectations have been scaled back in recent years due to slowing growth in the economy, but nevertheless the share of gas is still targeted to grow from 6 per cent in 2017 to 8–10 per cent by 2020, and 15 per cent by 2030, implying an additional 250–300 bcm of overall demand by the end of the next decade. However, a confused pricing strategy which involves a regulated price that was last set in 2015 (and is currently significantly above the average cost of gas imports) has dampened demand, while messages about the coal industry are also mixed. A plan to restrict output from less economic mines appeared to point to an aggressive anti-coal policy, but this was reversed when the economic and social impact was seen to be too dramatic in 2016. As a result, it appears to have been left to individual regions to take specific action based on their own objectives and requirements. One example of this is Beijing, where the government established a goal to reduce coal consumption from 13 million tonnes in 2012 to 7 million in 2017. This objective has been met by closing all four of the coal-fired generating plants around the city, and also by embarking on a phase-out of coal-fired boilers for commercial and residential use in favour of gas systems in all its urban



The competitiveness of gas and coal in the Indian power sector

Source: 'India's gas market post-COP21', Anupama Sen, OIES Paper NG120, June 2017.

districts. As a result, gas demand is expected to double over the 2010–20 period, reaching 20 bcm by the end of the decade.

'… ACROSS CHINA AS A WHOLE, AIR POLLUTION WAS ESTIMATED TO HAVE CAUSED AS MANY AS ONE MILLION DEATHS IN 2013.'

A key driver of this strategy has been air pollution, and this perhaps points the way towards the strongest case for gas in many developing countries. Beijing suffers from regular periods of hazardous smog, and according to 'China's smog is as deadly as smoking, new research claims' (Time Magazine, 23 December 2016), across China as a whole, air pollution was estimated to have caused as many as one million deaths in 2013.

However, in a recent survey by the World Health Organization, no Chinese cities appeared in the top 20 most polluted cities in the world, although 13 of these were located in India. Indeed, one of the key catalysts of the Indian government's aggressive gas objective is to start the process of changing this picture. As a result, there is a clear dilemma to be resolved. Gas is more expensive than coal but can provide a solution to a potential air quality crisis in many countries; governments will therefore have to provide more than just words, and gas producers will have to do more than just demand a premium price, if an optimal outcome is to be found.

The key for gas producers will be to reduce costs, especially for LNG imported to developing countries, to try and ensure that the delivered price

'GAS IS MORE EXPENSIVE THAN COAL BUT CAN PROVIDE A SOLUTION TO A POTENTIAL AIR QUALITY CRISIS IN MANY COUNTRIES.'

can be close to the US$5.50/MMBtu level needed to make gas economic in the Indian power sector. Perhaps a range of US$6–8/MMBtu would be more realistic if governments are prepared to take on the challenge of allocating an increased cost to coal output and consumption – either via a carbon tax, which China is considering, or via reduced subsidies for domestic production. In either case, however, the case for gas in developing countries is likely to be based on the willingness of governments and consumers to pay what will inevitably be a premium price for cleaner air quality.

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