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The Future of Gas

Contents

In 2016, the Oxford Institute for Energy Studies began a major new research initiative on the future of gas, initially examining the proposition made by gas companies and advocacy organizations in the 2010s that gas could be not just a transition fuel but also a destination fuel for a low-carbon energy future. That proposition was based on the arguments that switching from coal to gas would yield carbon reduction advantages and that gas could play a valuable role in backing up intermittent renewable power generation. Early conclusions of this research were that, in carbon-centric European countries, the policy and environmental communities have found these two arguments unconvincing. Moreover, questions have been raised increasingly regarding the impact of methane leakage from the gas chain, leading to doubts about the industry's overall greenhouse gas advantages. By the late 2010s, European Union policymakers had made clear that to ensure a longer-term future in European energy balances, the gas community would need to provide a narrative – backed up by investments – showing how the gas sector would be decarbonized in the post-2030 period.

Alongside research on the long-term future of gas, the Natural Gas Research Programme has continued its work on key shorter-term issues of importance for future pipeline and liquefied natural gas (LNG) supply and demand. Outside Europe and other carbon-centric (mainly OECD) countries and regions, the future of gas depends not just on carbon reduction commitments made at the 2015 UN Climate Change Conference, but also importantly, and in many countries significantly more immediately, on its contribution to the improvement of urban air quality, and its affordability both in absolute terms and relative to alternative sources of energy.

This research has identified a number of major questions which need to be considered in different time frames:

- whether, looking across regions and countries, the determining factor for the future of gas will be carbon reduction targets, or air quality, affordability, and security-of-supply issues, particularly in the major markets of China and India
- whether gas can find a place in market sectors where it has hitherto not been present in most

countries, particularly the transport sector

- the speed and extent of development of low- or zero-carbon gas – biogas, biomethane, and hydrogen – from various sources
- the future of different parts of the gas value chain – production and network infrastructure (LNG terminals, transmission networks, distribution networks, and storage facilities) – which may be different, with different adaptation options, in different countries and regions
- the importance of cost reduction, particularly in the LNG value chain, since the majority of the increase in internationally traded gas will be in the form of LNG.

This issue of the *Oxford Energy Forum* addresses all of these questions, and is based on an on-going series of papers; published work by the authors from OIES and the Sustainable Gas Institute at Imperial College is listed on page 26. The issue examines a number of these key themes for the shorter- and longer-term future of both methane (natural gas) and non-fossil gases in relation to the value chain itself, and reviews developments in different regions.

Martin Lambert looks at the development of biogas, biomethane, and hydrogen (from renewable energy, so-called power-to-gas or P2G) as alternatives to natural gas (methane). He concludes that even under an optimistic scenario, renewable gas (however derived) will require policy and financial support to be competitive on any significant scale. Projections of biogas and biomethane production of 50 billion cubic metres (bcm) in 2030 and around 100 bcm in 2050 only equate to 10–20 per cent of current European gas demand, and therefore significant additional supply would be needed in order to maintain anything close to its current scale. This raises the issue of hydrogen, but P2G is at a very early stage of development. However, unlike biogas/biomethane, which is constrained by the availability of sustainable feedstock, the main uncertainty with P2G is the cost of electrolysis and methanation.

Jamie Spiers looks at the future of low-pressure gas networks and the extent to which these substantial assets can be converted to transport decarbonized gases and in particular hydrogen. These networks provide substantial heat and energy storage, which will be difficult and costly to replace by other methods. Using the UK as an example he shows that given technical uncertainties, cost estimates for any of the decarbonization options – whether based on electrification or decarbonized gas – are problematic. The future challenge will be to establish an optimal balance of electrification and gas system options which maximizes decarbonization at an acceptable cost.

Paul Balcombe examines the problem of methane leakage from the gas chain. Since methane is a much more powerful greenhouse gas than carbon dioxide, any venting from exploration and production operations, or leakage from pipeline networks, has a much greater impact on climate warming potential than carbon dioxide. Although measurement of methane emissions is complex and disputed, a major contribution could be made by addressing the problem of `super-emitters', with the top 5 per cent contributing on average 50 per cent of US and European emissions. Leak detection and repair programmes are under way, but more progress needs to be made in order to establish an agreed and verifiable national methodology for measurement of emissions.

James Henderson reminds us that, alongside all of the new climate-related gas issues, security of supply remains an enduring concern in both Europe and Asia, and views about its importance, and how best to resolve its challenges, differ markedly both across and within regions. In Europe the primary concern is the role of Russian gas, while in Asia it is ensuring the competitiveness of (mostly) imported LNG against other sources, (mostly) domestic coal and renewables. But competitive advantage may be less important where there is a need for quick resolution of serious air quality problems which are a consequence of emissions from coal burning.

The potential increase in Chinese and Indian gas demand, and in particular LNG imports, will to a large extent depend on the affordability of gas in those countries, and their very different approaches to price reform and environmental (especially air quality) policy. *Stephen O'Sullivan* notes that Chinese price reform has been on-going for many years but has speeded up since 2014. It seems likely that Chinese gas demand, particularly in the residential and industrial sectors, will continue to increase strongly for at least the next few years – due to government targets for coal to gas switching in pursuit of air quality improvement – even with increasing prices. By contrast, for India, *Anupama Sen* shows that price regulation provides insufficient incentives to develop domestic gas resources, and at import prices significantly above $5 per million British thermal units, LNG will struggle to compete in any sector other than transport, with that situation unlikely to be impacted by some of the worst urban air quality anywhere in the world. The contrast between the short- to medium-term future of gas in the two countries could hardly be greater.

Strongly related to the issue of affordability, and given the importance of LNG for the future of the natural gas trade and hence demand in many countries, *Brian Songhurst* and *Claudio Steuer* show how the costs of LNG liquefaction plants have been falling since the extremely high levels of the early 2010s. They expect this to continue due to simplification of design codes, greater standardization of units, sequential building of multiple trains, and the use of floating liquefaction for offshore gas fields. Cost reduction will be the key to achieving final investment decisions on many projects which have been under development for some years, and for ensuring that those projects are able to provide competitively priced gas.

Finally, *Chris le Fevre* examines the potential future for gas in marine transport, given the new regulations introduced by the International Maritime Organization, which has mandated a limit of 0.5 per cent sulphur in fuel oil (the dominant fuel for marine transportation) beginning in 2020. While LNG can be part of the solution to this problem, it is too early to say that ship owners will consider it the preferable solution. Only a small number of large-scale operators have made a clear commitment to LNG-fuelled ships, and it remains to be seen how many others will follow.

BIOGAS, BIOMETHANE, AND POWER-TO-GAS

Martin Lambert

Introduction

This article reviews the status and potential development pathways for three low-carbon alternatives to fossil-derived gas: biogas, biomethane, and power-to-gas (P2G). It concentrates predominantly on Europe, since this has been the main focus for significant recent development of renewable gases. While the US, Japan, Australia, and some other non-European countries have some biogas, biomethane, and P2G projects, these are smaller than their counterparts in Europe. China has millions of very small biogas units in rural households, a legacy of the 1970s, but has been less active in modern biogas development.

Production of renewable gases

Biogas

From the mid-2000s to around 2014 there was a rapid increase in the number of biogas plants in Europe, but with changing legislation the rate of growth has slowed in recent years.

By the end of 2016 around 17,000 biogas plants were in operation, of which around 10,000 were in Germany (attracted by government incentives). These biogas plants nearly all use anaerobic digestion (AD), the biological breakdown of organic material in the absence of oxygen. Around 75 per cent of the plants, typically located on farms, use either agricultural waste or energy crops as feedstock. Of the remainder, about two-thirds use sewage and one-third are located at landfills and capture gas which otherwise would have been vented to the atmosphere. The composition of biogas from AD varies depending on feedstock and process conditions. Typically, biogas from AD comprises between 50 and 65 per cent methane, up to 50 per cent carbon dioxide (CO_2), and small amounts of other gases and impurities. When the biogas is burned, the CO_2 is typically vented to the atmosphere. While this CO_2 is also a greenhouse gas, it can be argued that since the CO_2 has been only recently captured from the atmosphere, the biogas production cycle does not add to the total inventory of CO_2 in the same way as combustion of fossil fuels.

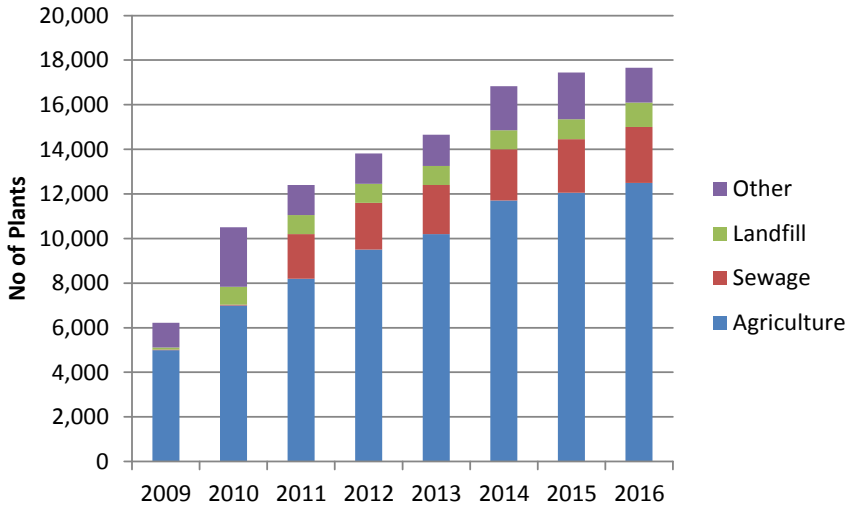
Most biogas is used locally near the point of production for production of electricity or heat or both. Each generation facility is small, generally with an electrical generation capacity between 1 and 2 megawatts (MW). This is about the same output capacity as a medium-sized wind turbine, but with the advantage that timing of biogas production can be more controlled than intermittent wind and solar generation. Thus, biogas can provide a low-carbon complement to intermittent renewables, as demonstrated in some German *Energiedörfer* (energy villages), which are at least self-sufficient in energy production through a combination of solar, wind, and biogas. Total electricity production from biogas in the EU is about 60 terawatt hours (TWh), or about 2% of total EU electricity production. With a reduction in government incentives, particularly in Germany, construction of new biogas plants has slowed dramatically since 2014.

While raw biogas (a mixture of methane and CO_2) has better environmental credentials than fossil-derived natural gas, its primarily local use and its small scale in comparison with the overall energy system make it of limited direct relevance to a discussion on the future of the natural gas industry and use of existing gas infrastructure. On the other hand, it is relevant as a potential feedstock for production of low-carbon natural gas substitutes, as discussed in the following sections.

Biomethane

Biomethane is much more directly relevant to the future of the current gas industry. It typically contains over 90 per cent methane, and its composition is such that it is suitable for injection into the gas grid where it can be comingled with fossil-derived natural gas. Development of significant quantities of biomethane in Europe started later than that of raw biogas,

Number of biogas plants in Europe by Feedstock type



and today it remains smaller in terms of overall production. While there are over 17,000 AD plants producing biogas, there are only around 500 biomethane plants. In 2011, total biomethane production was just 752 gigawatt hours (GWh), but by the end of 2016 this had grown to over 17,000 GWh, equivalent to around 1.6 billion cubic metres (bcm) of natural gas. This is significant growth, but biomethane production is currently less than 1 per cent of total natural gas production in Europe, and only around 0.4 per cent of total natural gas consumption.

Biomethane can be produced in a variety of ways. Most of it is currently derived by upgrading biogas produced by AD as described above. Upgrading involves separating the methane from the CO_2 and other impurities in order to achieve a composition acceptable to the natural gas grid. A variety of methods (absorption, adsorption, membrane filtration, and cryogenic separation) can be used. Biomethane can also be produced by a process of thermo-chemical gasification, for example using woody biomass or municipal solid waste as feedstock; this is sometimes referred to as bio-SNG (synthetic natural gas). The gasification approach has not been commercialized at any scale, and there are only a few pilot or demonstration plants (for example, Güssing in Austria, in operation since 2002, and Swindon in the UK, where a pilot plant was completed in 2016 and a demonstration plant is due for completion in late 2018). Biomethane can also be produced by P2G, as discussed in the next section.

Power-to-Gas

P2G relies on the principle of electrolysis – using electricity to separate water into its component parts, hydrogen and oxygen. While the principle has been known since the middle of the nineteenth century, and experimental P2G pilot plants were developed in the late 1990s and early 2000s, the potential for widespread commercial deployment has come to the fore in about the last five years, particularly with the availability of intermittent renewable power generation in excess of immediate electricity demand. With the technology still at an early stage of commercialization, there is a wide range of alternative approaches and no consensus on how the hydrogen produced from P2G can best be deployed in a decarbonizing energy system.

One possibility is for the hydrogen to be used directly as a transport fuel. This is potentially one of the highest-value applications, particularly by displacing oil products for long-distance heavy-duty transportation, including railways and potentially marine transport. For short-range and light vehicles it will compete with electricity and is thus less likely to have a significant role.

It could also be used directly to produce heat, particularly for industrial applications that require higher temperatures. It could be stored and used later to generate electricity (through either combustion or a fuel cell), thereby helping to balance the electricity grid. In this application, the P2G/gas-to-power combination is playing a similar role to batteries, but with the potential for storage of larger quantities of electricity over a longer period than is currently possible with batteries.

It could, within certain limits, be injected into the natural gas grid. Current regulatory standards generally impose strict limits on the amount of hydrogen in the gas grid (for example, 0.1 per cent in the UK and 0.02–0.5 per cent in the Netherlands). There is a growing consensus that a higher hydrogen content, certainly up to 1 per cent and in many cases as high as 5 per cent, could be accommodated without affecting the gas grid or end-user equipment. (These blend percentages are on a volumetric basis; hydrogen has an energy density about one-third that of natural gas, so the energy blend percentage is correspondingly lower.) Too high a hydrogen content would raise technical and safety concerns, but tests are being planned to test the impact of higher concentrations (for example, the Hydeploy project at Keele University in the UK, contemplating up to around 20 per cent hydrogen).

Finally, and perhaps most directly relevant to a discussion on the future of gas, the hydrogen can be used in a methanation process, in which it is reacted with carbon (usually CO_2) to produce biomethane of a quality suitable for injection into the natural gas grid. Various catalytic and biological methanation methods have been developed at a demonstration scale (1–10 MW of electricity consumption) in recent years:

- The Audi e-gas project at Werlte in Lower Saxony, Germany, has been in operation since 2013, comprising 6 MW of electrolysis located alongside a biogas plant. The CO_2 is separated from the biogas and combined with the hydrogen in a thermo-catalytic methanation process.
- Another Audi e-gas project at Allendorf in Hesse, Germany, started operation in 2016 using a different biological methanation process. Unlike the thermo-catalytic method at Werlte, it has the advantage that the CO_2 does not need to be separated from the biogas stream before upgrading.
- Similar to the Allendorf plant, the BioCat project near Copenhagen in Denmark consists of a 1 MW electrolyser and uses biological methanation to upgrade biogas from an adjacent water treatment plant.
- The Store&Go project, sponsored under the EU Horizon 2020 programme, is testing the integration of power-to-methane into the daily operation of European energy grids. It has demonstration sites at Falkenhagen in north-eastern Germany, Solothurn in Switzerland, and Troia in Italy. The three sites use different methanation technologies and connect to the natural gas network in different ways.

P2G vs. hydrogen production via methane reforming

In applications which supply hydrogen to end-consumers (typically either for heat or transport), P2G competes with reforming of natural gas (either steam methane reforming or autothermal reforming), combined with carbon capture usage and storage. Two examples being contemplated in the UK illustrate this:

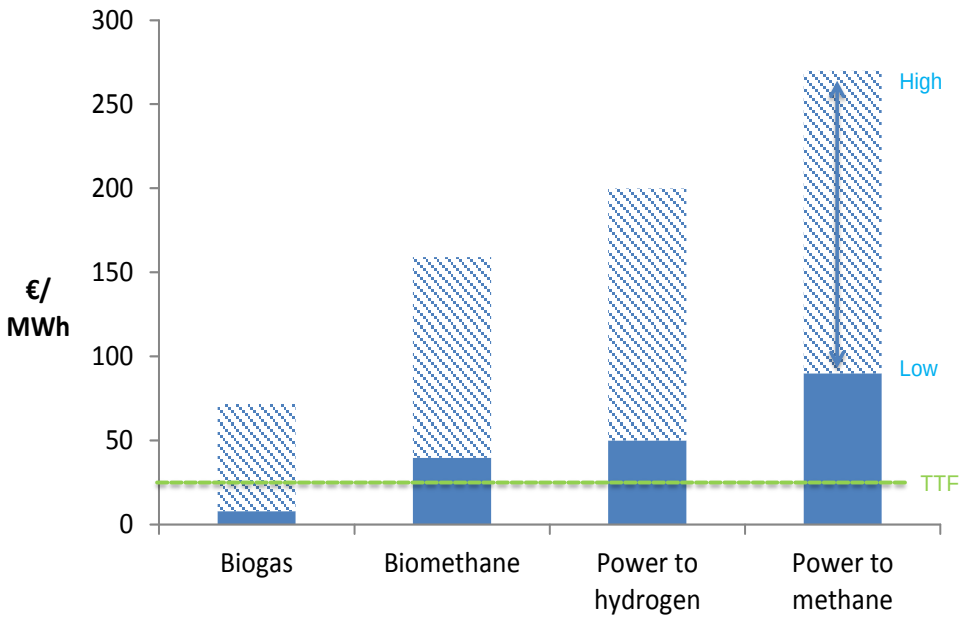
- The Hynet North West project in the Liverpool-Manchester region plans to reform methane, store the resulting CO_2 in nearby offshore depleted gas fields, supply pure hydrogen to a small number of industrial customers, and blend some hydrogen into the natural gas grid at levels which would not impact end-users.
- The Leeds H21 project is similar, but more ambitious, in that it proposes to convert equipment of all end-users (household, commercial, and industrial) in the city of Leeds (around 265,000 consumers) to burn hydrogen rather than natural gas. The hydrogen would also be produced by methane reforming, in this case on the east coast of the UK, with the resulting CO_2 being stored in depleted gas fields in the North Sea. The scale of such a conversion is significant: if the same process were extended to all current UK gas consumers, it would require conversion of 20,000 consumers per week for 25 years.

These projects are dependent on suitable CO_2 storage being available nearby, which will not be the case elsewhere – for example in Germany, where carbon capture and storage opportunities and acceptability appear limited.

Economics, carbon savings, and potential for further growth

As noted above, while biogas production has been deployed at considerable scale and so can be considered a mature technology,

Estimated cost of renewable gas alternatives compared with natural gas



biomethane is less developed, and P2G is very much at the demonstration (precommercial) stage. Against that background, it is difficult to be definitive regarding economics and potential for further growth, but some tentative conclusions can be drawn.

The level of carbon savings is also highly dependent on the specific supply chain and production method being considered. A 2015 report by the Joint Research Centre of the European Commission estimated typical greenhouse gas savings from biogas compared to EU fossil-fuel benchmarks. Savings were assessed to be at least 70–80 per cent and in some circumstances (particularly utilization of wet manure) were over 200 per cent. The topic of CO_2 emissions from agriculture is complex and beyond the scope of this paper, except to note that there are initiatives underway (for example Biogasdoneright) to promote low, or even negative, carbon emissions from improved agricultural methods combined with biogas production.

For biogas (from AD), the key metric is the levelized cost of electricity (LCOE) of the resulting power generation. The International Renewable Energy Agency has estimated the LCOE in the range of US$0.06–0.14 per kilowatt hour. The lower end of this range is roughly comparable with the LCOE of wind and solar. While wind and solar costs are projected to continue to fall, there is less evidence of further cost reduction potential for biogas. On the other hand, biogas production does not suffer from unpredictable intermittency.

For biomethane, comparing costs for use as a vehicle fuel, the International Renewable Energy Agency shows a wide range of costs: around US$14–40 per million British thermal units or €40–115per megawatt hour (MWh). These costs are roughly consistent with other studies (for example, Ecofys's 2018 study *Gas for Climate* and ENEA's 2016 publication *The Potential for Power-to-Gas*). Even the lower end of this range is well in excess of the comparable cost of fossil-derived natural gas, confirming that use of biomethane will need to continue to be supported by government incentives and/or regulations aiming to reduce carbon emissions.

The cost of gas from P2G is highly dependent on the assumed price for electricity and the load factor (number of hours of operation per year). If low-cost (<€15/MWh) electricity were available 75 per cent of the time, the cost of methane from P2G could approach €50/MWh and so be competitive with biomethane derived from biogas. If, however, low-cost electricity were only available 10 per cent of the time, or electricity costs averaged around €40/MWh, the resulting cost of gas could be as high as €170/MWh.

Most renewable gas alternatives are still more expensive than fossil-derived natural gas. Thus, their development depends heavily on government policy support. However, given the goal of a carbon-neutral energy system by 2050 (and an 80 per cent reduction from 1990 levels by 2040), further government support is highly likely. This in turn may be expected to lead to further cost reductions, particularly for biomethane and P2G, building on experience from the initial plants. The European Network of Transmission System Operators' 10-year network development plan, published in March 2018, contemplates in its most bullish scenario that biomethane injection into the grid could reach around 360 TWh (35 bcm equivalent) by 2030, rising to 530 TWh (50 bcm) by 2040. This is around 10 per cent of projected gas demand in 2030, and about half of the indigenous European natural gas supply (excluding Norway). The same report is much less bullish regarding the role for P2G, contemplating, even in its most optimistic global climate action scenario, just 13 TWh (1.2 bcm) of P2G-derived gas injected in 2030, rising to 95 TWh (9 bcm) by 2040. The report does note, however, that P2G is an emerging technology and its role may increase in future.

An alternative scenario, in Ecofys's 2018 study *Gas for Climate,* sees the potential for 98 bcm of biomethane production by 2050, plus a further 24 bcm of renewable hydrogen from P2G.

Conclusions: impact on the future of gas

Purely from a cost perspective, it appears that even under an optimistic scenario, renewable gases will not be competitive with fossil-derived natural gas before 2050. Thus, further development of renewable gas production will depend on policy and regulatory support, and a continued drive to reduce carbon emissions to achieve or exceed the goals set at the 2015 UN Climate Conference.

Assuming, as is likely, that the drive to reduce carbon emissions continues, development of biomethane, primarily by AD but potentially also by gasification, is likely to continue, and EU production in excess of 50 bcm per year by 2050 at a cost of €50–100/MWh appears likely.

P2G is at an earlier stage of development, and its future is more difficult to predict. Considerable uncertainty and debate remain about whether the best use of existing gas infrastructure is to carry renewable methane or to be converted to hydrogen. Further analysis of the total system costs of these alternatives and the interaction between gas and electricity networks will help guide future decisions and policymaking. The cost of P2G is highly dependent on the

price of the input electricity, which in turn depends on the regulatory framework for the electricity sector and the availability of low-cost surplus renewable generation. While biogas and biomethane production is constrained by availability of suitable sustainable feedstocks, the growth of P2G production is only constrained by the availability of sufficient low-cost electricity and the business case for the required investments in electrolysis and methanation.

Overall, it appears that there are sufficient renewable gas supply alternatives to enable continued use of existing gas infrastructure even when use of fossil-derived natural gas has become environmentally unacceptable. Unless the scale of production becomes larger than studies currently suggest, however, gas will have a significantly smaller share in the future energy supply than it enjoys today. While the use of existing gas infrastructure makes economic sense, it may be more difficult to justify significant new investments in gas infrastructure without greater clarity on the role of gas in a decarbonized energy system.

THE FUTURE OF LOW-PRESSURE GAS NETWORKS

Jamie Speirs

The future of gas networks is uncertain and contested, mainly due to the carbon dioxide (CO_2) and methane emissions associated with natural gas systems. Gas networks are used in many countries to deliver natural gas to industrial, commercial, and domestic consumers, supplying energy for a range of services, including space heating, water heating, and cooking. However, emerging and increasingly binding carbon targets will likely preclude the unabated use of natural gas. This may lead to the stranding of extensive gas network assets in many countries if decarbonized uses of these assets are not established.

Existing low-pressure networks are extensive, with an estimated 2.8 million kilometres of gas transport pipelines globally. Low-pressure gas networks deliver a significant amount of energy annually to commercial and domestic consumers (over 8,000 terawatt-hours globally), with a large proportion of this used for heating buildings. However, unabated natural gas use in the domestic and commercial sectors is unlikely to be compatible with climate change goals. The carbon emissions created by burning natural gas in modern gas boilers is in the range of 230 to 318 grams of CO_2 equivalent (gCO_2eq) per kilowatt hour (kWh) of heat, including supply chain methane emissions.

The CO_2 and methane emitted by natural gas systems and the difficulty of capturing emissions at domestic, commercial, and many industrial end-uses, is a problem for global carbon reduction ambitions. Country-level scenarios show a reduced role for gas networks in the future, often preferring electricity and heat pumps to decarbonize domestic and commercial energy services. However, there are significant technical, economic, and consumer barriers to electrifying heat, which have made widespread uptake of electric heat challenging. Given these concerns, there is a growing argument that decarbonized gas networks could play a major role in the future energy system and contribute significantly to decarbonization. The options and their costs and greenhouse gas (GHG) emissions are discussed below.

Options for decarbonizing the gas network

Reducing GHG emissions from gas distribution networks may involve decarbonizing the gas in the network or reducing its use sufficiently to remain within emissions targets. The latter may involve using gas only during peak demand through hybrid gas/electric heat pumps or other gas/electric hybrid systems at domestic or district scales. There is only limited evidence for the viability of this option. There is, however, an evidence base focused on the decarbonization of gas and its implications for gas networks.

There are three broad aspects of decarbonizing gas networks:

- the gas generation options for both hydrogen and biomethane
- the network issues arising from these options, including what new infrastructure or reinforcement may be needed
- the consumer implications of gas network decarbonization.

The two main gasses that can potentially provide decarbonized energy are hydrogen and biomethane. Hydrogen can be used for heat or electricity generation, or as a transport fuel. The key benefit of hydrogen over natural gas is that there are no CO_2 emissions from combustion. Hydrogen can also be used in fuel cells using electrochemical conversion, with no direct CO_2 emissions.

Several techniques are used to produce hydrogen, including

- converting natural gas to hydrogen through a reforming process
- splitting water into hydrogen and oxygen using electricity and an electrolyser
- converting solid fuel, including

woody biomass or coal, to hydrogen through a gasification process

- converting wet biomass to hydrogen through anaerobic digestion, potentially using natural gas as an intermediate.

An estimated 48 per cent of total global hydrogen production, which amounts to 55 million tonnes per year, is from steam methane reforming of natural gas. Reforming of oil contributes around 30 per cent, gasification of coal 18 per cent, and electrolysis of water 4 per cent.

Biomethane is derived from organic feedstocks such as plant material and waste. Biomethane can be a direct substitute for natural gas with limited impact on the downstream infrastructure or consumers, as long as gas specifications are maintained. Biomethane can be produced from a variety of processes, but these are typically based on anaerobic digestion or methanation of biologically sourced hydrogen.

These various routes to decarbonized gas have a range of different implications for infrastructure requirements. First, different types of gas production plants are required, depending on the method of producing hydrogen or biomethane. These plants then need to be connected to the gas network. In the case of biomethane, the infrastructure requirements are likely minimal, with pipework needed to link a plant to the gas network, usually at the local transmission system level or below. Hydrogen will require infrastructure at the national transmission system (NTS) scale to transport large volumes of gas at high pressure. It is unlikely that hydrogen will be able to use the existing NTS for two reasons:

- The steel used in NTS pipework is often not an appropriate material for the transmission of hydrogen at high pressure due to issues of embrittlement affecting pipework integrity.
- The existing NTS will likely be needed to transport natural gas to industrial and power generation customers, who may have the option to decarbonize through carbon capture and storage, maintaining the compatibility of natural gas with climate goals.

In contrast, lower-pressure distribution pipework may provide a suitable infrastructure to transport hydrogen. This has, in part, been facilitated by the modernization of gas distribution systems, often involving the replacement of older iron and steel with plastic materials, often medium- or high-density polyethylene. This new pipework is thought to be more compatible with hydrogen. This fact is central to a number of demonstration proposals in the UK, which have plans to transport hydrogen to domestic gas consumers through the existing gas distribution network.

Gas storage is another challenge for decarbonized gas vectors. A combination of gas network line-pack and dedicated gas storage sites are used in the current gas network to manage variation in daily and seasonal demand. While biomethane can utilize existing infrastructure with little intervention, hydrogen will likely need bespoke gas storage capacity. Demonstration proposals often meet this requirement by suggesting the creation of new geological salt cavern storage facilities for inter-seasonal storage of hydrogen.

There are also considerable implications for end consumers. While consumers of hydrogen can use fuel cell technologies to generate heat and electricity, many recent proposals focus on the use of hydrogen as a combustible fuel in hydrogen-ready boilers, cooking appliances, and gas fires. In either case it is likely that existing appliances will need to be modified or replaced in order to be hydrogen-ready. Other changes to consumer properties potentially include replacement or modification of gas metering and pipework from the meter to end-use appliances.

An important implication of a transition to hydrogen relates to the quantity of resources needed to facilitate gas production at sufficient volumes. Biomethane production relies on the availability of biomass resources. These are naturally constrained, and potentially competed for by a number of other end-uses including power generation and transport fuel. For example, estimates of the available resource for biomethane indicate that it may be sufficient to supply 5 per cent of UK gas demand in the future. The addition of municipal solid waste as a renewable energy resource may add to this supply estimate, but will likely meet less than half of future UK gas demand. Countries with lower gas demand and more domestic sources of suitable biomass may meet greater proportions of gas demand through biomethane. For any country, reducing future demand and prioritizing biomass for gas production will reduce the deficit between resource availability and demand. However, biomass is unlikely to become the dominant source of decarbonized gas in Europe or globally. Production of hydrogen from methane also has consequences for resources, with the efficiency losses incurred in converting natural gas to hydrogen increasing demand for natural gas by 10 to 35 per cent.

The options discussed above have implications for both costs and GHG emissions. These issues are explored below.

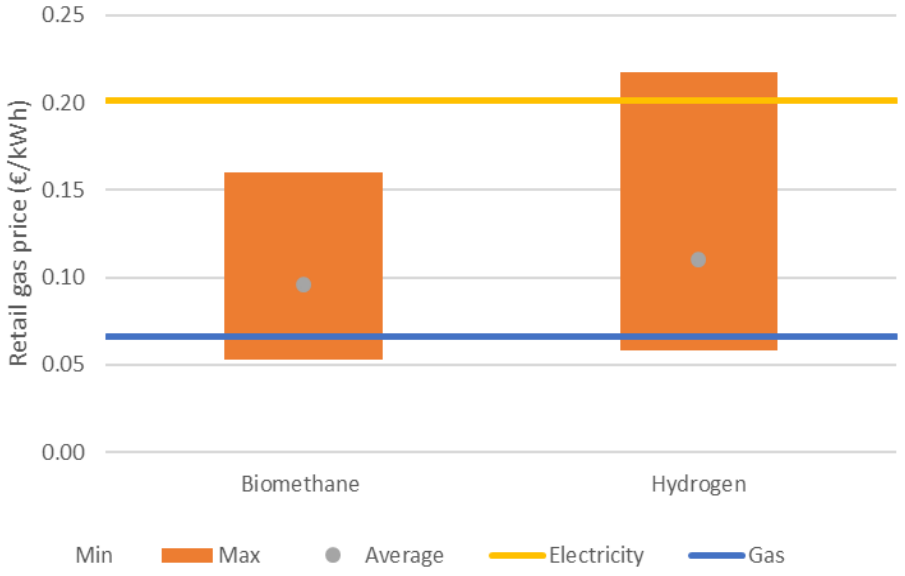
Costs of decarbonizing the gas network

Each option for gas network decarbonization has a variety of different costs – such as production, network, and storage costs – which combine to create different cost implications for the end user. The costs relate not only to the network infrastructure but also to the wider supply chain implications of each option. The full system implications of particular options are difficult to estimate without the use of whole-system modelling tools, given the interconnected nature of the impact on system costs.

The ultimate cost to consumers is a function of the cost of gas production; the cost of gas transportation through gas networks; the cost of end-user appliances and services; and administrative, profit, and tax costs throughout the supply chain. The cost estimates for different decarbonized gas options vary significantly. The retail price achievable based on these costs might be €0.052–0.161/kWh (average €0.096/kWh) for biomethane and €0.058–0.218/kWh (average €0.11/kWh) for hydrogen.

These prices exclude the costs of converting gas users to hydrogen-compatible systems. Estimates can be compared to the EU average retail price of natural gas, €0.066/kWh, and the EU average retail price of electricity, €0.209/kWh (both in 2015). If the future efficiency of methane- or hydrogen-fired boilers is 90 per cent, the cost of delivered heat ranges from €0.058 to 0.178/kWh for biomethane and €0.064 to 0.241/kWh heat for hydrogen. For comparison, at heat pump efficiencies of 250 per cent, and a retail electricity price of €0.201/kWh, heat pumps could produce heat for €0.08/kWh.

Estimated retail price of decarbonized hydrogen and biomethane compared to the EU average retail price of natural gas and electricity in 2015



The additional cost of converting consumers to hydrogen gas networks may be over €3,500 per household, including appliances and supporting equipment such as metres and domestic service pipes. This can be compared to the cost of installing air source heat pumps in the UK at €4,700 to €13,000 or ground source heat pumps at €15,400 to €23,600.

Carbon emissions from gas network options

The primary reason for assessing the role of gas networks in future energy systems is to assess their role in achieving targets that avoid dangerous temperature increases of more than 1.5–2°C. Therefore, a thorough assessment of the GHG emissions associated with different options is necessary. It is important that technological options provide both an immediate reduction in climate impact and the possibility of deeper decarbonization in the future. For example, the reforming of natural gas to hydrogen without carbon capture and storage will lead to more GHG emissions than natural gas per unit of energy produced, highlighting the need to carefully regulate the development of hydrogen markets in the future.

The range of CO_2 emissions estimates for the different methods of producing low-carbon gas is extremely large: −371 to 642 gCO_2eq/kWh for hydrogen and −50 to 450 gCO_2eq/kWh for biomethane.

UNDERSTANDING AND REDUCING METHANE EMISSIONS FROM NATURAL GAS SUPPLY CHAINS

Paul Balcombe

The world has long since woken up to the urgency of reducing carbon dioxide emissions, culminating in a challenging set of international and national climate targets. However, for methane, the second most important anthropogenic greenhouse gas, only recently has action gathered pace on understanding and reducing emissions. Methane is a potent climate forcer, and whilst annual emissions are only 4 per cent of those of carbon dioxide (CO_2), methane has had 58 per cent of the total climate forcing impact that CO_2 has had since

1750: anthropogenic CO_2 emissions have contributed 1.7 W/m^2 to total climate forcing, and methane emissions have contributed 1 W/m^2. The critical contribution of methane emissions to climate change has generally been under-appreciated, but reducing methane emissions (from oil and gas supply chains as well as other sources) is vital in limiting peak temperatures and reducing the rate of temperature rise.

This article describes methane emissions from natural gas supply chains in terms of how much we know about them, their impact on the climate, how we can reduce them, and what else we need to understand.

Methane and climate change

Methane is a strong greenhouse gas, 120 times stronger than CO_2 in terms of climate forcing. Climate forcing is the change in heat balance in the atmosphere caused by an increase in greenhouse gas concentration. However, it is relatively short-lived and has a perturbation lifetime of 12 years. Consequently, its relative impact on the climate decreases over time. CO_2, on the other hand, has a complex atmospheric life span in which 50 per cent of an emission is removed from the atmosphere within 37 years but 22 per cent effectively remains indefinitely.

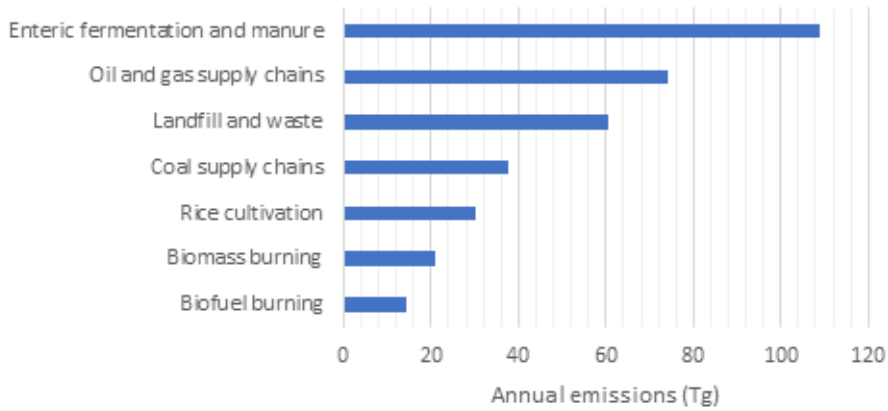
Global warming potential (GWP) is often used to compare different greenhouse gases, but this metric has some limitations. Perhaps most importantly, its value depends on the time frame considered. For example, in a time frame of 100 years, which has been the global standard, the GWP of methane is 36 times that of CO_2, but in a 20-year time frame, often used to represent short-term climate impacts, the GWP of methane is 87 times that of CO_2. Given that these figures are used as straight multipliers in emissions calculations, the impact of the time frame is linear and large.

Other limitations to the use of the GWP relate to aspects of its definition and construction. It estimates the relative impact of a greenhouse gas not on temperature, which is the basis of most climate targets, but on climate forcing. And it measures the average impact of a pulse emission over a time period, rather than the impact at a specific endpoint of a sustained emission, which may better reflect reality.

Alternative metrics, such as the global temperature change potential, address some of these limitations, but there is no clear best option. This may generate some uncertainty in measuring the climate impact of methane for emissions studies or for abatement investment decisions, but it is important to note the following:

- Addressing both short-term and long-term climate impacts is crucial in meeting climate targets to limit temperature change to 2 degrees, therefore the use of both a 100 year and 20 year time-frames will help to understand these different perspectives.
- We must reduce *both* CO_2 and methane emissions if we are to meet climate targets up to 2100.

Annual global methane emissions from anthropogenic sources



The contribution of natural gas to global methane emissions

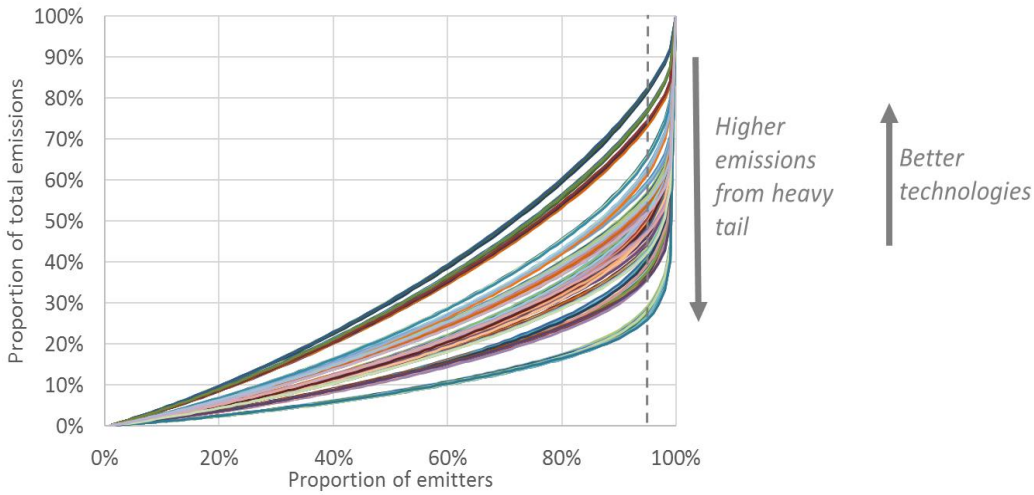
Methane emissions arise from various sources, both natural and anthropogenic. Natural sources (wetlands, oceans, and wild animals) make up approximately 40–50 per cent of global methane emissions. Anthropogenic sources include agriculture (mainly livestock and rice cultivation) and waste (~200 teragrams [Tg]/year), fossil fuel supply chains (~110 Tg/year), and biomass and biofuel burning (~30 Tg/year). Among anthropogenic sources, oil and gas supply chains are the second largest contributor.

It is difficult to distinguish between the contributions of methane emissions from oil and gas supply chains, given their partially shared infrastructure, but it is clear that methane emissions from the natural gas supply chain are significant and highly variable across different regions. The natural gas supply chain is long and complex, and emissions of methane may arise via operational or maintenance vents, incomplete combustion (e.g. flared gas), or fugitive emissions (e.g. caused by malfunctioning equipment or operational error). Global emissions from gas supply chains are typically estimated at 1–3 per cent of total gas

production; the International Energy Agency's 2017 World Energy Outlook estimates them at 1.7 per cent.

Substantial research has been conducted over the last five years to measure and estimate methane emissions from different gas supply chains, in particular in North America. Whilst emissions associated with the majority of facilities are relatively low, there is high variability and the distribution of emissions is skewed. Emissions vary by region, reservoir type, supply chain equipment, and age of infrastructure, to name a few factors. It has been asserted that methane emissions are higher from US supply chains than from others, but more evidence is required to verify this. Whilst robust, transparent, and independent measurements of emissions from US supply chains have been almost comprehensive, in other regions these are severely lacking. Additionally, certain stages of the supply chain are missing transparent data, in particular liquefied natural gas (LNG) routes, where there is significant potential for intermittent fugitive emissions and vents.

Distribution of emissions across different natural gas supply chains



Super-emitters

A small number of facilities contribute disproportionately to total emissions; these are known as super-emitters and have been found in all studies that have investigated the distribution of emissions. The unusually high emissions are likely due to either equipment malfunction or operator error. They may be intermittent or continuous, depending on the source, and they are at least partially stochastic and therefore somewhat unpredictable. The heavy-tailed distribution of emissions is not uncommon across other process systems, but the importance of super-emitters in natural gas supply chains cannot be understated due to their impact on climate change.

The graph above shows the skewed distribution of emissions across a variety of technologically different supply chains based on recently available data from the US and Europe. Each line represents a different theoretical supply chain with a different technological makeup (e.g. an unconventional gas well that uses reduced-emissions completions equipment, not requiring liquids unloading, distributed through plastic pipes). The shallower lines represent more skewed distribution, where the top 5 per cent of emitters contribute on average 50 per cent of total emissions, with a range between 25 and 75 per cent.

The challenge to reduce emissions

Clearly, supply chains that use modern and emissions-reducing technologies are likely to exhibit a less skewed distribution with fewer potential super-emitters. These technologies include reduced-emissions completions equipment, effective compressor seals, replacement of gas-driven pneumatics, and replacement of iron distribution mains with polyethylene pipe. But technology alone will not eliminate super-emitters.

To remediate high emissions, it is first necessary to detect them. Thus, monitoring and measuring techniques are key. Leak detection and repair (LDAR) programmes are currently the most popular industry method of reducing fugitive emissions, with the objective of periodically checking all equipment for leaks and repairing where possible. Typically, LDAR consists of manual detection of a leak with an infrared camera, estimation of the size of the leak (based on either concentration or flow rate), and then a remediation step. These operations are relatively costly due to their personnel and equipment requirements, and consequently the prevalence of LDAR is uneven across companies, countries, and supply chain stages. The suitable frequency of LDAR efforts per year has been discussed in relation to recent US and Canadian policies on methane emissions, but it is clear that there is no single suitable frequency. For example, LDAR is particularly costly for transmission assets which span long distances.

To reduce cost, innovations in automatic emissions detection and monitoring are required. Much research

is on-going in this area, particularly in the US, but there may need to be an incentive, either regulatory or market-based, for industry to innovate and roll out these measures. Additionally, better detection would lead to more effective methane regulation. The US and Canada have already set the pace with regulation and reduction of methane emissions from the oil and gas industry, whilst the European Commission is currently debating options for the inclusion of methane-related policy measures in the next EU Energy Strategy. It is clear that our understanding of methane emissions and how to reduce them is improving, but so is the urgency of taking action if we are to meet global climate targets.

THE IMPACT OF SECURITY-OF-SUPPLY ISSUES ON THE FUTURE OF GAS

James Henderson

It is perhaps an obvious statement that energy plays a fundamental role both in fuelling economic growth and in sustaining the life of a nation, with one clear example being the vital provision of warmth in winter. As a result, a primary concern for consumers, and for the politicians whom they elect to serve their interests, is that there should be no interruption to the energy supply – indeed, any significant disruption can bring a government down.

The fundamental importance of this issue calls for a thorough understanding of the concept 'security of supply'. To fully understand how it applies to the gas sector, it is important to disaggregate the general term and establish what steps can be taken to minimize the impact of the key issues. There is a broad literature devoted to the attempt to find a universal definition, with Yergin providing one classic suggestion that 'the objective of energy security is to assure adequate, reliable supplies of energy at reasonable prices and in ways that do not jeopardize national values and objectives.' This was subsequently shortened and simplified by the International Energy Agency to 'uninterrupted availability of energy sources at a reasonable price', but even this leaves room for wide interpretation – what is a reasonable price, for example?

What seems clear, though, is that energy security is more of a policy goal than a specific characteristic of an energy system, and as such is relatively open to the interpretations of individual policymakers. The goal of energy security is sometimes also expressed in terms of the four A's – availability, affordability, accessibility, and acceptability – with the overall objective being to find an equilibrium between secure physical supply, stable price, and, increasingly, environmental impact. However, each of the terms continues to lack specificity, making it difficult for the energy industry to be clear about the parameters it needs to satisfy to be seen as secure. Furthermore, all the academic literature which attempts to find a more precise and measurable definition runs into the problem that energy security appears to be context dependent. Threats or vulnerabilities are seen differently according to whether the actors are producers, consumers, or transit countries, for example; they also depend on geography, national policies, business ties, history, and on-going state interactions. As Sovacool and Saunders have put it, 'energy security and energy systems are value laden', implying that even in similar circumstances there can be multiple answers to questions such as for whom security should exist, for which values, and from what threats.

A key catalyst for these concerns occurs when energy is imported and can therefore be disrupted in transit or at source by parties beyond the control of a home government. Renewable energy and nuclear power tend to be excluded from the security-of-supply debate as they are normally generated in-country and therefore not subject to external influences. All hydrocarbons, however, are traded within regional or global markets, and their free flow and availability are vital to ensure consumer confidence. Coal and oil are traded in liquid markets with multiple actors across various geographies, meaning that the commodities are easily transferable in the event of supply disruptions, although the price is uncertain. History has shown that although major suppliers can cause a panic by adjusting or restricting supply, in general it is assumed that global markets provide security in themselves.

With gas, however, the situation is rather different. Trade has traditionally been carried out by pipeline, often under long-term contracts, implying a strategic link between supplier and consumer accompanied by inevitable political and commercial risks. The liberalization of some markets, for example in Europe and the US, and the increasing development of liquefied natural gas (LNG), which has started to encourage more global flows of gas by providing seaborne interconnections between customers on different continents, has started to shift perceptions; but nevertheless, the view that security of supply is a key issue for the gas industry remains prevalent. Consequently, any consideration of the future of gas in the global energy economy is intimately linked to the confidence of energy consumers that gas can be provided on a consistent and guaranteed basis at an affordable price.

Although, as noted above, one should expect the numerous actors across the global gas sector to have different views of energy security, two incidents, one in Europe and one in Asia, have shaken the confidence of gas consumers over the past few years and challenged the concept of gas as a secure and reasonably priced source of energy supply. In Europe in 2009, a two-week interruption of the supply of Russian gas through Ukraine severely undermined the perception of Russia as a secure source of supply. In Asia in 2011, the Fukushima nuclear disaster catalysed an emergency call from Japan for extra LNG. The gas ultimately arrived, but only as a result of a dramatic surge in price – which lasted for up to four years (2011–2015), created the perception that gas is an expensive fuel, and undermined the incentive to give it a significant long-term role in the region's energy mix.

To take the European example first, the 2009 Russia–Ukraine dispute arose over non-payment by Ukraine for Russian gas, and inability of the two countries to agree on new price and tariff terms for gas supply and transit. These issues had threatened to create a crisis every year – and had done so previously (but much less seriously) in 2006 – but the 2009 events resulted in no Russian gas flowing through Ukraine for two weeks. Of course, this was not an entirely commercial decision, as it also put pressure on Ukrainian President Viktor Yushchenko, who was a fierce critic of Russia but who was seeking re-election in January 2010. The stoppage of Russian gas flows through Ukraine during a cold winter period caused significant shortages in a number of countries, particularly in south-eastern Europe, and the overall consequences would have been more serious had Europe not just entered a severe recession, with a consequent reduction in energy demand.

This supply disruption was widely blamed on Russia, and the European reaction to it focused not only on support for Ukraine but also on addressing the clear security-of-supply issue of reliance on a single country for such a large proportion of imports. The Third Gas Directive, which was aimed at increasing competition in the gas market in Europe by breaking down control over the vertical gas chain, became law in 2011, and Gazprom increasingly found itself required to conform to its unfolding provisions. At the same time, Russian market dominance was challenged by the European Commission, with the competition authority (DG COMP) starting an investigation into its activities in central and eastern Europe in 2011, which was completed earlier this year.

Furthermore, in the crisis resulting from the annexation of Crimea in 2014, the European Commission introduced the Energy Union concept in 2015, which affirmed its commitment to a fully integrated energy market and called for the diversification of Europe's sources of energy, and in 2017 introduced a specific Security of Gas Supply Regulation. This further encouraged the interconnection of markets and called for solidarity between member states in the event of a gas crisis, creating specific regional groups that would assess common supply risks and agree on emergency measures.

Creation of physical and virtual hubs combined with physical interconnection of previously isolated markets, means that the European Union has arguably been very successful, both commercially and logistically, in reducing its vulnerability to any interruption of Russian supplies. These strategies make sense for any importer of energy that wishes to avoid the risk of dependence on a single source of supply. Diversification of supply options, in this case largely LNG via the region's extensive regasification capacity, is an obvious strategy, while interconnection of markets should ensure that no single country is left to face a supply threat in isolation. The creation of emergency response plans

The price of LNG in Asia, 2010–2018

and increased transparency can also help to alleviate security concerns.

Indeed, it would probably be fair to say, from a commercial perspective, that Europe has done as much as it can to protect the security of its gas supply. Unfortunately, from a political perspective, views among member states vary considerably, highlighting the issue raised earlier that security-of-supply concerns depend heavily on context. For example, Poland – where gas accounts for only 13 per cent of primary energy, one-third of the supply is produced domestically, and 80 per cent of imports come from Russia – regards dependence on Russia as a significant political risk. In contrast, Slovakia – where gas accounts for 30 per cent of primary energy, only one-fifth is produced domestically, and 99 per cent of imports come from Russia – appears to be much more sanguine.

The Polish perspective, which it is clearly promoting in Europe, is that the security of supply equation is simple: gas = Russia = Putin = bad. However, this is not just bad for Russian gas, causing problems for import pipelines such as Nord Stream, it is also bad for gas in Europe as a whole, as the region's options are limited. Restricting Russian gas flows, which are large and highly competitive, would inevitably push the price of gas in Europe up, thus making the fuel less competitive than alternatives such as coal and (a more likely competitor) renewables. Alternatively, Europe could theoretically simply reduce its use of gas in order to limit exposure to Russia, but again this is hardly a positive outcome for the continent's gas industry and would be almost impossible to enforce in a liberalized market in which private companies operate freely.

For the time being it would seem that many customers are taking a more Slovakian point of view, though. Russia gas reached record export volumes in 2016 and 2017; its price was competitive, and alternatives were few as indigenous production continued to decline and LNG was attracted to Asia. However, over the longer term it would seem that, despite the EU's best efforts to reduce the commercial risks, physical security-of-supply concerns focussed on imports from Russia could undermine the future of gas in Europe.

Asia offers something of a contrast: although physical security of supply is obviously an issue, especially in island nations such as Japan and Taiwan, the emphasis has shifted somewhat to the question of whether gas will be priced competitively with alternative fuels. This is particularly due to the prevalence of cheap indigenous coal in the region but was also catalysed by the high price of gas in the 2011–2014 period. This was the result both of higher oil prices, to which LNG contracts are still largely linked, and of the supply–demand tightness that arose from the extra Japanese demand after Fukushima. After 2014, the development of new projects in the US and Australia and the fall in oil prices have combined to ease the situation, and although rising oil prices in 2017–2018 are a potential cause for concern, it is likely that the current market balance will be maintained until the early 2020s. Nevertheless, the perception of gas in many countries is that it is a premium product, and not a fuel that can necessarily provide a long-term solution on a cost-competitive basis. Furthermore, there is a real potential for further tightness in the global gas market in the mid-2020s, and therefore a rebound in prices, because of the lack of project FIDs (final investment decisions) in the past few years.

As a result, the challenge in Asia is for the gas industry, and in particular the LNG industry, to prove that gas can be made available at reasonable cost. Stern (2017b), in his analysis of the future of gas in the global energy economy, has identified a range of $6–8/mmbtu (million British thermal units) as an acceptable level for gas to be affordable across a range of countries both in and outside the Organisation for Economic Co-operation and Development, while the International Energy Agency's World Energy Outlook 2017 showed that demand tends to be reduced – even in countries such as the UK, Germany, and the US – when the gas price exceeds $6/mmbtu. Therefore, the target for upstream producers is very clear – growth in demand will only be achieved over the long term if gas can be delivered to customers in this price range.

The other two A's in the security-of-supply criteria also deserve a brief mention. Accessibility is likely to remain an issue in developing gas markets as new, costly infrastructure is required to supply customers. As a result, gas companies may have to invest across the value chain in order to create a market for their fuel and provide the necessary security of supply. This may be a new and complex business model for them, and very different from what is permissible in mature markets like Europe, but it is likely to be necessary to secure the future of gas demand. Finally, acceptability largely concerns the environmental impact of gas, on which views are again split between Europe and much of the rest of the world. In Europe, gas appears to be increasingly viewed as a carbon-emitting fuel and thus part of the long-term environmental problem. As a result, the industry needs to develop a decarbonization strategy to have a secure future. By contrast, in Asia, gas can (at least over the next decade) be part of the solution to air quality problems in cities that currently rely heavily on coal. Recent evidence from China shows how much gas demand can be generated from coal-switching; but in poorer countries, this benefit can

still be outweighed by the price differential; and in the longer term it may be the case that gas, if too expensive, misses out in a broader switch from coal to renewables or nuclear.

In conclusion, security of supply is clearly an important issue for the long-term future of gas, even if views about it differ markedly across regions. In Europe, the Russia question dominates, and although the EU has done all it can to alleviate the commercial and infrastructural risks, the political dynamic may still undermine the role of gas in the region. Elsewhere, security of price as well as accessibility will be important factors, although in these cases the gas industry can at least take more proactive steps to secure its future. Action may also be required to ensure the long-term acceptability of gas in a decarbonizing energy system; but at least in the short term, its role in improving air quality can provide a boost over the next decade.

AFFORDABILITY OF GAS AND LNG: THE CONTRAST BETWEEN CHINA AND INDIA

Stephen O'Sullivan and Anupama Sen

Most future global gas demand projections focus on China and India because of their large populations, energy demand, current reliance on coal, and environmental problems (especially urban air quality). Rapidly increasing demand for gas, and specifically imported liquefied natural gas (LNG), in China surprised virtually all gas analysts in 2017 and looks likely to dominate global demand increases over the next few years. The contrast with India, where gas demand fell over the past five years before stabilizing in 2017, could not be greater.

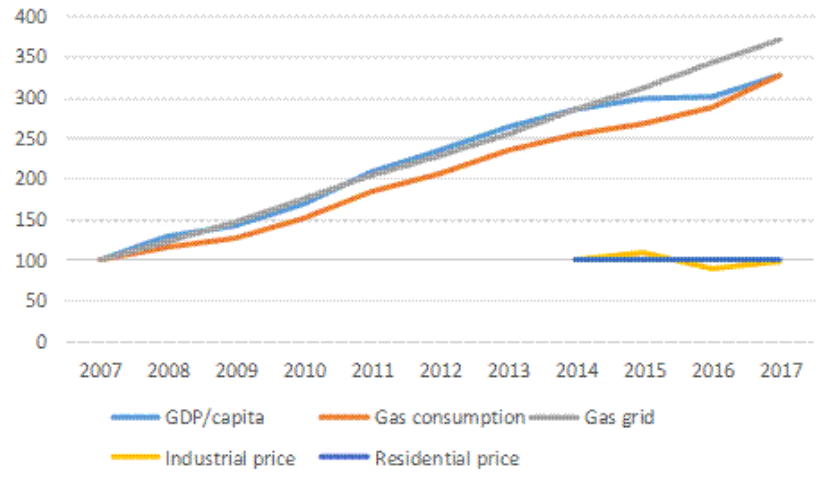
While differences in the structure of the two economies, the political importance of urban versus rural populations, and the sources of urban air pollution account for part of the difference in gas demand outcomes, a substantial factor is affordability of gas and particularly imported LNG. There is a distinct lack of convincing work on price elasticity of gas demand from gas analysts, whether from academia, consultancy, or industry. But empirical observation of the impact of price levels (especially for LNG imports) on demand suggests much greater affordability in China than India, combined with much greater coherence and commitment to price reform and air quality improvement. At import prices significantly above $5 per million British thermal units (mmbtu), Indian LNG will continue to disappoint, whereas Chinese affordability levels are much higher.

Gas price reform in China

Gas price reform has been a long-running process in China, with the first modest moves in 1982. The pace of reform has picked up in recent years; there has been a significant change in the structure of gas pricing, and the citygate (wholesale) price has seen several revisions. In June 2018, the decision was taken to allow residential prices, which had been heavily regulated for decades because of their political sensitivity, to rise to (but not above) the level of non-residential prices. One year later, they will be completely freed and set by negotiation between the gas suppliers – principally China's national oil companies (NOCs) – and the city gas distribution companies. Residential consumption represents around 20 per cent of total Chinese demand.

Nevertheless, much of China's end-user price framework remains regulated. The broad category 'industrial' represents more than 60 per cent of total demand. Almost three-quarters of this is regulated, and non-residential citygate prices have varied over the past few years with some degree of influence from the market. However, the formula approach adopted by the Chinese government in late 2011 resulted in prices which are more advisory or consultative than mandatory, while the interval between price adjustments also remained long

Trends in Chinese gas demand and underlying economic factors, 2007–2017



Note: values for GDP, gas consumption, and connections to the gas grid are indexed to 100 for 2007; industrial and residential end-user prices for Beijing are indexed to 100 for 2014.
Sources: BP, World Bank, CEIC, NDRC.

with just five non-residential price revisions over the past four years.

The impact of changing wholesale prices on gas demand has been complex. Citygate prices are not the same as end-user prices: the former are typically paid to the NOCs by intermediaries (such as city gas distribution companies); the latter include the intermediaries' distribution costs and a permitted return on their assets.

These prices are regulated by local pricing bureaus, and it can take up to a year after a citygate price change before there is a direct impact on consumer purchasing decisions. Prices for direct sales from NOCs to large industrial users and sales of offshore gas produced by the China National Offshore Company are not regulated.

Analysis of the effect of residential pricing on demand presents special problems. Residential price tiering was introduced in China by the end of 2015, with the 5 per cent of households using the most gas paying around 50 per cent more than the base price, and the 15 per cent of households immediately beneath these `super-consumers' paying around 15 per cent more than the base price.

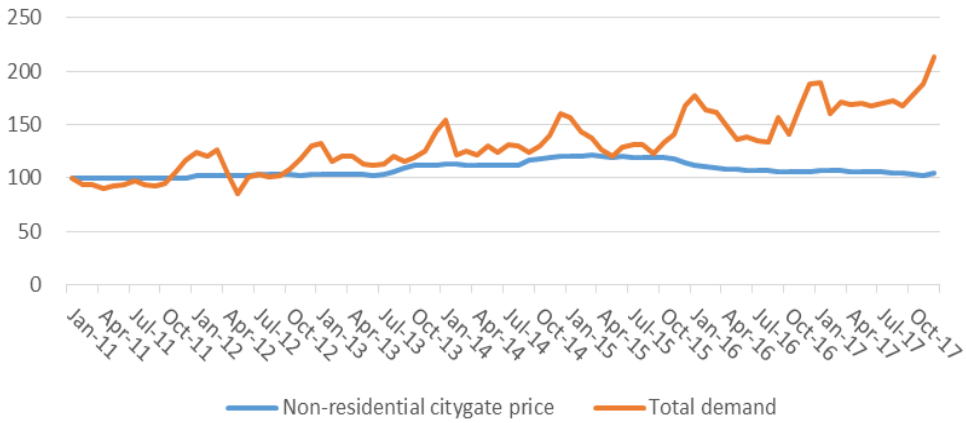
Before 2007, demand was constrained by a lack of supply, but the arrival of LNG imports in 2006 changed the analytical framework. Since 2007, the largest single influence on gas consumption appears to have been growth in GDP per capita. From 2007 to 2017, gas demand rose by 229 per cent to reach almost 240 billion cubic metres. Per capita GDP growth was almost exactly the same, rising 228 per cent to $8,700 in 2017, suggesting that GDP change has the greatest impact on gas demand growth. The second greatest influence has been the steady expansion of the gas grid, which has opened up new markets. Over the past decade, the number of people with access to gas rose almost fourfold. Overall gas demand has grown slightly more slowly than that – perhaps because of the changing industrial structure of the Chinese economy and falling energy intensity.

Reliable end-user pricing data is currently available for a three- to four-year period for several cities, including Beijing and Shanghai. Industrial end-user prices fell by around 6 per cent over 2014–2017 in Beijing and were flat in Shanghai; in both cases, prices in the intervening years were higher than currently. The cities of Wuhan and Tianjin have shown similar trends, albeit over shorter time frames. Residential end-user prices for customers with average demand have been stable in Beijing, Shanghai, and Tianjin for several years, although tiering was introduced three years ago for household consumers with the highest demand. As noted earlier, citygate prices are in the process of being fully deregulated – which will, over time, flow through to end-user prices.

While residential end-user prices have remained stable over a relatively long period, industrial (and other non-residential) end-user prices were increased across China in 2014, which slowed demand growth from 9 per cent in 2014 to 5 per cent in 2015. This was reversed by the end of 2015 when prices were cut by around 30 per cent during that year, partly in response to the slowdown in demand. With the time lag for citygate prices to work their way through to industrial end-user prices, and no change in residential prices, 2016 saw a pickup in demand to 8 per cent. This would no doubt have continued into 2017 at a similar pace, but a major external factor began to drive the market from early 2017 and continues to this day.

The Chinese government's forceful introduction of a policy to switch consumers in northern China away from coal and towards natural gas has probably been the single biggest driver of gas demand over the last 18 months. Against a target of 3 million households to be converted, over-enthusiastic cadres converted almost 4 million without ensuring that there was enough gas to meet the demand. The result was a serious gas shortage across northern China and a scaling back of the programme's implementation. However, the programme of conversion from coal to gas is set to continue and expand to include southern China,

Relation of total Chinese gas demand to non-residential citygate price, 2011–2017; values indexed to 100 for 2007



targeting the conversion of a further 4 million homes in 2018. Very strong demand growth has continued, with an increase in the first quarter of 2018 of more than 17 per cent.

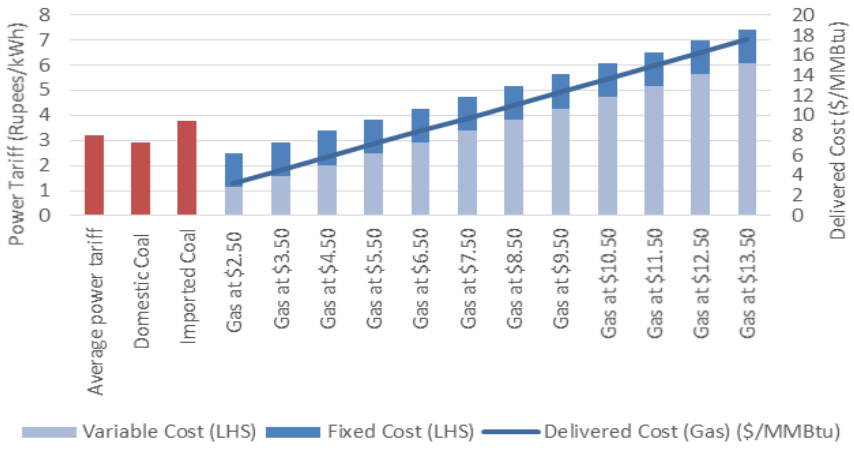
The relative lack of price sensitivity of gas demand over the past seven years is illustrated in the figure above, which shows total Chinese gas demand compared with the non-residential citygate price (this is the price that varies). The annual summer demand peaks can be clearly seen, as can the steady upward trend in gas demand. There seems to have been little impact on that demand growth even as the price peaked in early 2015.

In terms of overall affordability, when it announced that residential citygate prices would be deregulated starting in June 2018, China's National Development and Reform Commission highlighted that a household using 20 cubic metres of gas a month would see their gas bill rise by RMB 7 (around $1) per month. In the context of a nominal GDP of $8,800 in China (and higher in Beijing), affordability would not appear to be a significant issue. Even where per capita GDP is lower than in Beijing, such as western China, citygate prices are in many cases only half the level of richer cities like Shanghai.

For the industrial sector, the picture for gas is slightly different. Coal has consistently been a cheap industrial energy source, whereas gas is at the upper end of the price scale. In 2014, the price of gas was around two and a half times that of coal, a differential which had narrowed only slightly by 2018. (Gas prices were around parity with fuel oil in 2014 and slightly below it in 2017–2018, but in the intervening years they were significantly more expensive.) Hence, while gas in the industrial sector may be affordable, it is almost certainly not preferable, which is why government policy to switch industrial and residential users away from coal and towards gas has been such an important driver of China's gas demand over the past 18 months.

Looking to the future, it is clear that industrial demand has been influenced by gas prices; this can be seen in the pickup in demand that followed the price cuts near the end of 2015. That will likely continue, and the impact will also be felt in the residential sector, although the tiered pricing introduced some years ago has already had some effect in this area. Certainly, in the next couple of years, as the government's coal-to-gas policies continue to be rolled out across China, these policies will likely be the main drivers of gas demand growth – as they have been in 2017 and 2018 to date – rather than price or affordability.

Competitiveness of gas with coal in Indian power generation



Source: Sen (2017)

India: under- or over-rated as a major potential gas market?

India, a potential market of over 1 billion consumers, is viewed as a wild card in future global gas demand. Yet declarations by successive governments of gas's importance in the energy mix (including a doubling of its share from 6.5 to 15 per cent) remain at odds with the pricing of gas: prices have been too low to incentivize production, yet uncompetitively high relative to its alternatives in the Indian economy. The key to assessing the Indian gas market lies in understanding the affordability of gas in the context of on-going pricing reform.

Pricing reform

India's domestic gas prices are determined by the fiscal regime governing producing fields. As there have been frequent changes to this (cost-plus, profit-sharing, and most recently [2017] a revenue-sharing regime), there are multiple prices for domestic gas. However, in 2014 a reformed price formula was introduced for new production: a 12-month lagged, volume-weighted average of Henry Hub (US), National Balancing Point (UK), and Alberta (Canada) reference prices and the Russian domestic gas price. Prices for domestically produced gas may also converge to this formula upon the expiry of existing contractual price clauses.

As its introduction coincided with the global price downturn, the reformed price ($3.06/mmbtu for April–September 2018) failed to revive domestic production, which has been in decline since 2010. In 2016, a separate formula – linked to the prices of imported coal, naphtha, fuel oil, and LNG – was introduced for gas produced from

deepwater areas ($6.78/mmbtu for April–September 2018). Although this formula is a closer representation of the prices of fuels that gas is meant to replace in different economic sectors, it has yet to be tested, as a new licensing round for acreage offering this price was launched in early 2018.

Affordability and the importance of relative prices

The affordability of gas in India is influenced not just by the prices of its main alternatives across different consumer sectors, but also by infrastructure access and government policies. The gas utilization policy dictates that all domestically produced gas be released in order of priority to a first tier of end-users: city gas for households and transport, fertilizers, liquefied petroleum gas (LPG) manufacturing plants, and grid-connected power plants. The remainder is released into the general market including industry (steel, refineries, petrochemicals), commercial city gas, and captive and merchant power plants. Deficits are made up by importing LNG. The surge in LNG imports in India over 2015–2017 (rising from roughly 20–30 per cent of total gas consumption to nearly 50 per cent) was largely driven by the general-market end-users, which consumed around 50 per cent of it.

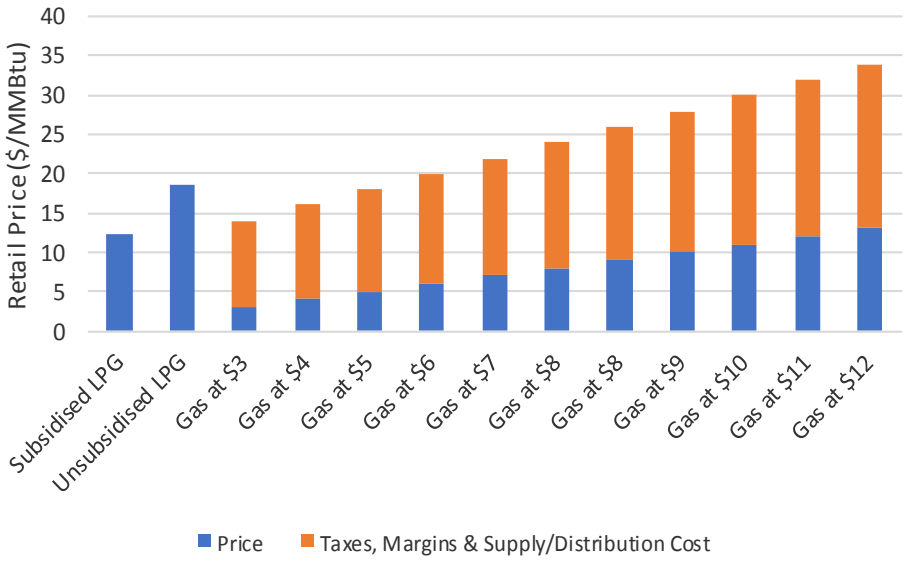
Gas consumption in the price-regulated fertilizer sector was similarly price-inelastic over the same period, due to a politically important subsidy on the retail price to farmers. Low global prices also made gas cheaper than its alternatives – imported naphtha and imported urea – and consequently, fertilizers accounted for around 30 per cent of LNG consumption over 2015–2017.

In contrast, gas in the power sector (both domestic and LNG imports, as shown in the figure above) has struggled to compete with its main alternative, domestic coal, at prices over $5/mmbtu, in the absence of a carbon tax (or alternatively, a subsidy on gas-based power), as electricity tariffs are regulated by Indian states and kept low.

The city gas sector, where prices are not regulated, can absorb higher-priced LNG, and following the removal of subsidies on its main alternatives (gasoline and diesel in transportation, and LPG for household cooking) is now competitive on price (see Sen 2017 for an analysis). However, city gas's growth is contingent on infrastructure expansion, a clear regulatory framework for network infrastructure, and the enforcement of environmental legislation to enable the substitution of gas for more polluting fuels. Four broad factors are likely to influence the short-term economics of gas demand and shape the longer-term outlook for gas in India.

- *Future LNG import prices.* Historical data shows an inverse relationship between LNG import prices and Indian gas consumption. If LNG prices remain sufficiently competitive in different economic sectors, consumption will continue rising, contingent on whether Indian companies can buy spot LNG, which may be at or below the competitive level. For instance, this price would be roughly $5/mmbtu or lower in the regulated power sector, but potentially higher for the unregulated city gas sector and for the politically important fertilizer sector, in which subsidies are likely to offset any price increase (see Sen 2017 for further analysis). Further, if buyers are committed to oil-linked prices for LNG imports, the level of oil prices will influence future gas demand both directly through the ensuing gas price, and through the prices of oil products which are alternatives to gas in many sectors.
- *India's commitments at the 2015 UN Climate Change Conference.* India has voluntarily committed to building 175 gigawatts (GW) of renewable (mainly solar) power generation capacity. The country's National Electricity Plan assumes that this will be met, requiring no more than 4.34 GW of gas-based capacity (in addition to an existing 25 GW) until at least 2027.

Competitiveness of Piped Natural Gas (PNG) with subsidised and unsubsidised LPG in Indian city gas distribution



Source: Sen (2017), data updated for 2018.

However, India's record low solar tariffs (e.g. a 2017 auction yielded $0.038/kilowatt-hour) exclude the costs of intermittency, raising questions over whether developers have adequately priced in risk and whether these projects will be completed on schedule. This opens up a potential balancing/bridging role for gas in the power sector, which will only become clearer as renewable project deadlines begin to kick in.

- *The future of coal in the energy mix.* Although the federal government has ramped up coal production to meet an election promise to provide universal electricity access to households by 2020, recent public litigation over worsening air quality in cities has led to the imposition of a tax on coal production ($6/tonne) and restrictions on coal plant emissions. The tax needs to be at least 4 times the current level to allow gas (which emits half as many pollutants as coal) to compete in power generation (see Sen 2017). But in the longer term, the environmental arguments against coal are likely to win out, as the government expects to contract no more than 50 GW of coal capacity (in addition to the existing ~200 GW) until at least 2027. However, should the renewables target fail to be met, this will support an expanded role for gas in power.
- *Gas infrastructure.* India's gas supply infrastructure is concentrated in largely industrial regions (the northwest and west) and is often underutilized due to gas's uncompetitive price position. Infrastructure is not expanding quickly enough in underserved regions, where companies have been reluctant to lay pipelines without an 'anchor' consumer (such as a large industrial plant) in place. Pipeline projects also sometimes face litigation over land use and compensation issues. India's downstream regulator (the Petroleum and Natural Gas Board) needs to be empowered to resolve such issues and define and enforce the rules of access to infrastructure.

The combination of poorly targeted price reform, relatively low affordability, infrastructure constraints, and competing renewables targets makes it difficult to be optimistic about short- to medium-term gas market potential in India, particularly if it needs to be driven by LNG imports.

THE COST OF LNG LIQUEFACTION PLANTS

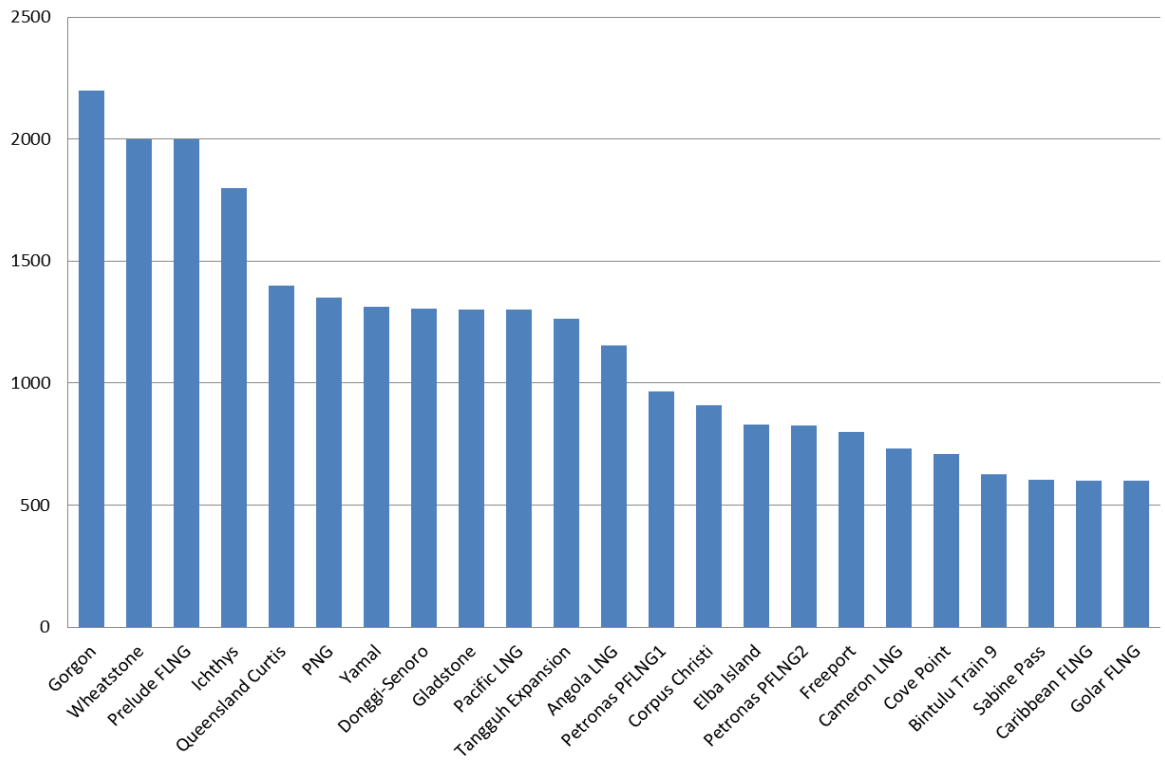
Brian Songhurst and Claudio Steuer

The cost of building liquefied natural gas (LNG) liquefaction plants has fallen significantly since the high prices of 2010–2014. The major projects during that period were in remote locations and included three floating liquefaction (FLNG) projects. Over 50 per cent of the 90 million tonnes per annum (mtpa) committed during this period occurred in Australia, which experienced a labour shortage, raising construction costs to an all-time high, and a very strong Australian dollar compared to the US dollar, on which the budgets and final investment decisions were based. These increased costs affected not only the liquefaction plants but also the upstream cost of producing the feed gas either from remote locations or using technologies such as coal seam gas extraction.

The costs in the figure on page 20 are based on money of the day for the liquefaction plant scopes only; they exclude upstream costs. Costs have fallen from highs of US$ 2,000 per tonne per annum (tpa) to $600–1,400 – a reduction of 30–50 per cent or more, which is excellent news for keeping the cost of LNG competitive. These reductions are also in line with the capital cost of other oil and gas facilities as reported by the IHS Capital Cost Index, probably due to the downturn in the industry due to reduced investment at lower energy prices, which increased competitive pressures on contractors and equipment suppliers.

The figure on page 21 summarizes a review of 71 final investment decisions during 1967–2017 accounting for 490 mtpa of liquefaction capacity and the corresponding oil price over the same period. Over 50 years, the average cost of liquefaction plants was $1,004/tpa (in 2018 dollars). During 2010–2014, 97 mtpa were committed at an average $1,574/tpa (in 2018 dollars), and during 2014–2017, 68 mtpa were committed at $975/tpa (in 2018 dollars) – an impressive 38 per cent reduction. Lower energy prices and unit costs and lower-cost locations all contributed to this performance. Around 75 per cent of the capacity committed during this period was in the Gulf of Mexico or on the US east coast. Separate analysis comparing lower- and higher-cost locations shows a significantly higher correlation between higher energy prices and higher $/tpa for higher-cost locations, most likely a function of complex projects in remote or high cost locations requiring greater infrastructure development (gas transmission system, maritime facilities, transport, living, medical, etc.), gas treatment and LPG fractionation facilities, larger tank storage capacity, and the impact of limited human resources, equipment and contractors cost inflation in various elements of the project scope.

Liquefaction plant capital expenditure constructed 2014-2018 ($/tpa)



Source: Collated by authors from various companies websites, PR Newswire, Reuters, Bloomberg, OGJ, IGU, GIIGNL.

In Australia, the unit technical cost $/tpa of all Queensland plants is considerably lower than the cost of plants in North West Australia (Gorgon, Wheatstone, and Ichthys). This is due in part to the latter's remote locations, their processing of associated gas, needing additional facilities for gas liquids recovery, despite being constructed later when labour rates were falling. Another factor in the lower costs of all Queensland plants may be the economy of scale. All three Queensland plants were built by the same contractor, using the same process technology, and more or less in the same time frame. It is likely that these costs could have been reduced even further if the plants had been combined on a single site and shared common facilities – for example, jetties, storage tanks, and utilities. Gorgon in North West Australia is also a special case because its environmental sensitivity necessitates CO_2 sequestration. Australian projects all carry the cost of quarantine for imported equipment, which other plants worldwide do not.

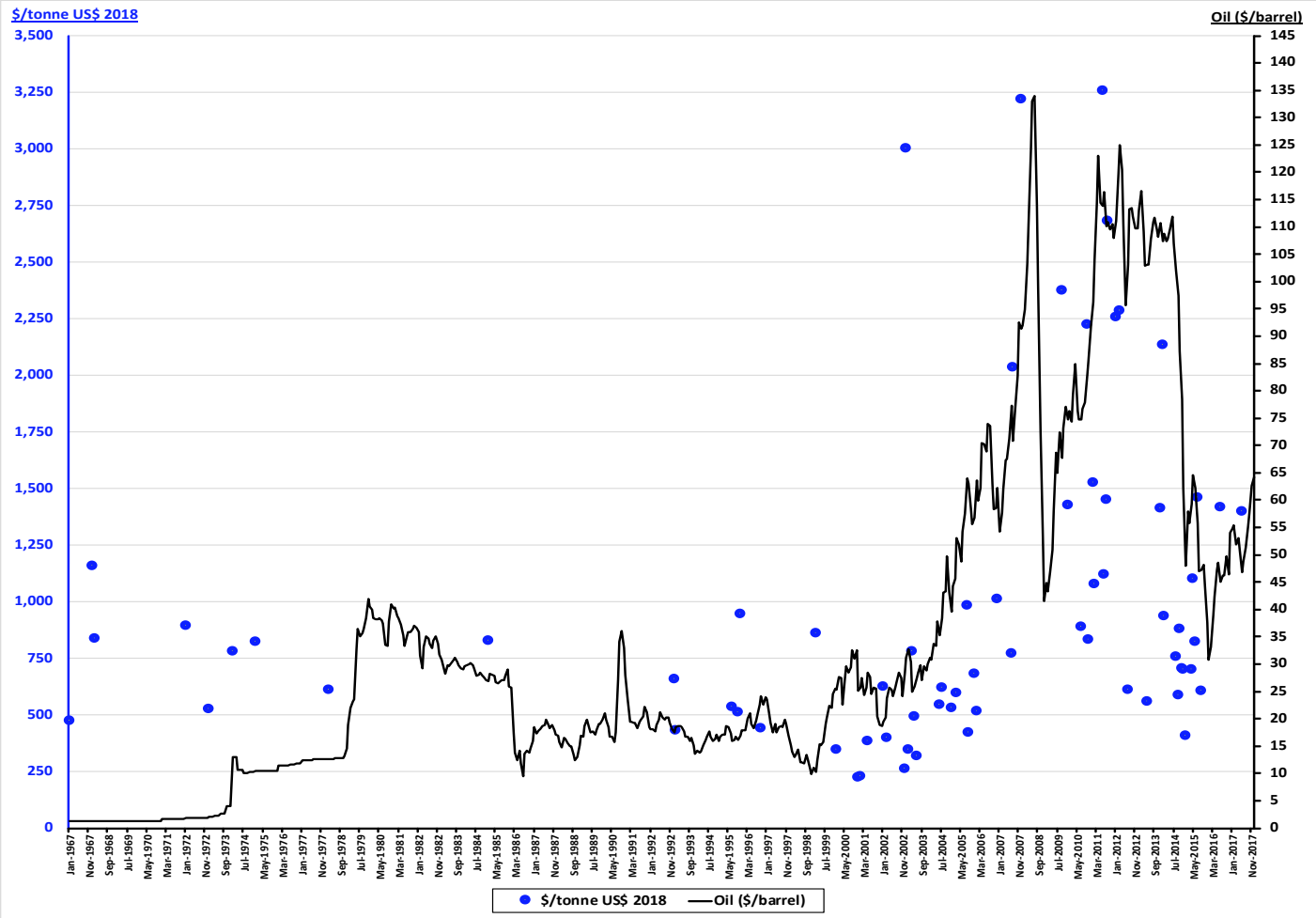
The Yamal plant in northern Russia is very cost-competitive considering it was built in a hostile Arctic environment, and Novatek have stated they expect to lower the cost of the next phase significantly by building the modules locally (discussed in more detail below).

The costs of the Queensland, Papua New Guinea, Yamal, Dongii-Senoro, and Tangghu plants are all in the range of $1,000–1,400/tpa, which was the industry norm in 2010 prior to the expensive Australian era. Thus, costs are back to where they were at the start of the decade.

The costs of the US plants in Texas, Louisiana, and Maryland are even lower, at $600–1,000/tpa, and set a new benchmark for the industry. There, a combination of three features has created a low-cost 'sweet spot' that will be difficult to beat:

1. The Sabine Pass, Cameron, and Cove Point liquefaction facilities were added to existing import terminals, thus taking advantage of existing LNG storage and jetties which can otherwise represent up to 50 per cent of the cost of a new plant. This is demonstrated by comparing these costs with Corpus Christi, at $900/tpa, which is a greenfield site requiring new tankage and jetties.
2. The owners are utility companies and full service LNG companies, not international oil companies and use more functional specifications for the design, procurement, and construction of the plants. This enables the use of suppliers' industry standard

Costs of liquefaction plants at the time of final investment decision (in 2018 US dollars) and corresponding oil prices, 1967–2017)



Data sources: Wood Mackenzie and World Bank.

equipment rather than bespoke equipment prescribed by major international oil companies. Major international oil companies have developed specific standards, based on their extensive experience, which are typically very demanding, and frequently require equipment suppliers to modify their standard plant, adding significant cost. Some suppliers have stated that they typically take their standard plant, strip it down, and rebuild it to meet these bespoke requirements, which not only adds 20–50 per cent to the cost but also extends the schedule.

3. Building multiple trains sequentially creates economies of scale by reducing engineering costs and enabling single purchase orders to be placed for multiple items. The sequential approach also allows for the efficient use of construction staff by moving them on from one train to the next, bringing all the lessons learnt from the previous train and enabling them to work more efficiently.

This approach was used very effectively on Egyptian LNG Idku Trains 1 and 2, where the trains were completed within 6–12 months of each other, taking full advantage of the synergies. Nigeria LNG Plus (Trains 4 and 5) demonstrated the benefit of successive site expansions capitalizing on improved infrastructure and local and international experience. This enabled a doubling of plant capacity with a 50 per cent reduction in costs per tonne for the additional capacity.

These plants are also processing treated lean pipeline gas, eliminating the need for extensive gas processing and liquids recovery and requiring only minimal acid gas treatment as typically required for associated (rich) gas. However, whilst this reduces the project scope and capital cost, project value is normally enhanced by producing higher-value natural gas liquids, which more than offset the higher cost.

This article has so far addressed onshore plants, but FLNG has also come of age and offers a competitive liquefaction alternative for offshore fields due to the avoidance of an expensive gas pipeline to shore and the advantage of lower shipyard fabrication costs. There are now five projects – Petronas PLNG1 is operating offshore Sarawak; Golar Episeyo, operating offshore Cameroon, shipped its first cargo to China in May 2018; Prelude is on a remote field approximately 475km North-North East of Broome in Western Australia and has started commissioning tests prior to receiving hydrocarbons from the field, and is expected to start up later in the year; Petronas PFLNG2 is currently under construction and expected to start production in 2020; and the first FLNG barge to be constructed, Caribbean FLNG, is awaiting assignment.

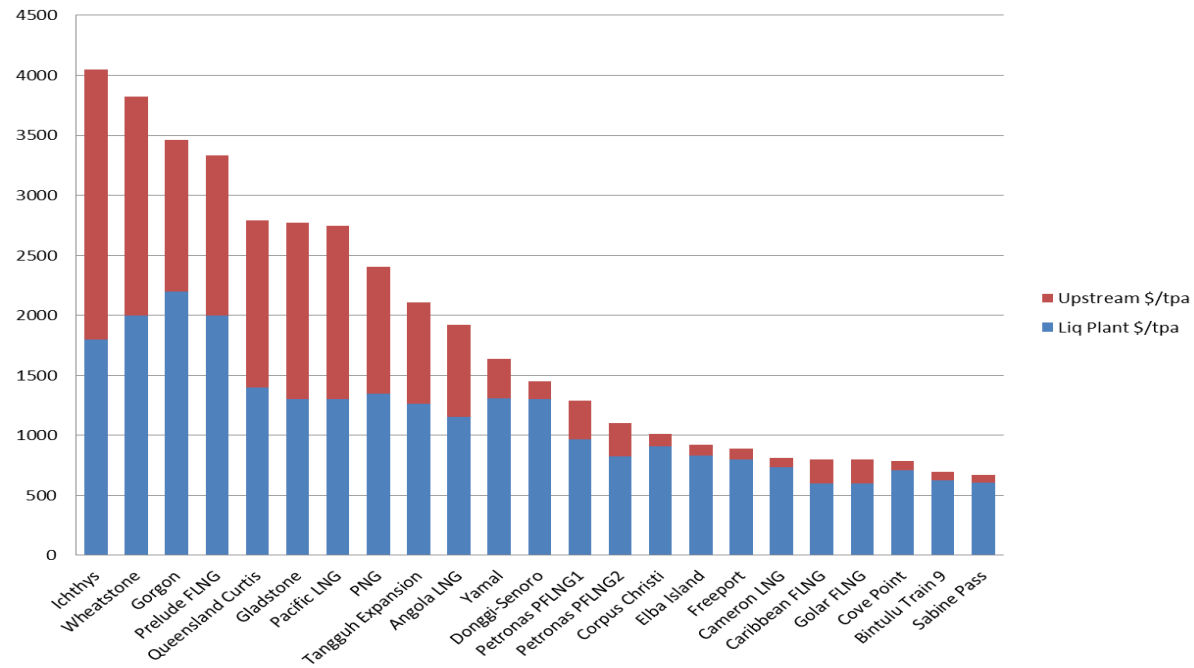
The costs of the Petronas, Golar, and Caribbean FLNGs appear to provide a competitive enabling technology for offshore gas fields, reducing the overall investment required to produce LNG and providing independent exploration and production companies with the possibility of unlocking gas reserves with a leased floating production storage and offloading (FPSO) unit. Prelude is considerably more complex – combining 5.3 mtpa of condensate, liquefied petroleum gas, and LNG production with the ability to stay on field during Category 5 winds – and thus more expensive. Twenty years of development with over 1.6 million hours of engineering and design were invested to develop a range of project design solutions, the benefits of which Shell believes will become more evident with successive project implementations.

Calculations of the cost of producing LNG also need to include the cost of the upstream facilities that deliver the feed gas to the liquefaction plant.

Upstream costs are driven by the extent of the facilities required to treat and transport the gas from the reservoir to the liquefaction plant. In the case of Ichthys, this is extensive, with a major offshore FPSO and an 890 km pipeline to shore. At the other extreme are the US plants, which require relatively short interconnecting lines to transport pipeline-quality gas from the natural gas pipeline system. US liquefaction plants up to now have relied on a wide independent network of pipelines and gas supply sources outside of the operational and financial control of the liquefaction plant venture and shareholders, paying a significantly higher feedgas price than a conventional integrated LNG project. Some new US LNG projects are seeking to reduce this feedgas volume and price risk by vertically integrating dedicated upstream assets as part of their overall LNG project.

For the Ichthys project, the cost of the offshore pipeline has been stated at around $2 billion ($250/tpa). This cost could have been eliminated if a floating LNG plant had been used. Based on the quoted costs for FLNG, this might have been a cheaper option than an onshore plant, although multiple units would have been required.

Upstream and liquefaction plant costs constructed 2014-2018 ($/tpa)



Source: Collated by authors from various companies websites, PR Newswire, Reuters, Bloomberg, OGJ, IGU, GIIGNL.

Looking forward, costs are likely to fall even further, for several reasons. The use of lower-cost FLNG facilities has become a realistic option, with two units now operating and one more scheduled to start up this year. FLNG facilities fabricated in shipyards (mainly in Korea) offer a lower capital cost and typically shorter schedule – or if not shorter, with a more certain completion date. Eni has chosen FLNG for its Coral South project offshore Mozambique. As FLNG demonstrates its technical and commercial viability, and financial entities become more knowledgeable and comfortable with the technology, a leased LNG FPSO business model will rapidly develop similar to oil FPSOs, permitting independent exploration and production companies to unlock gas reserves and export LNG with a reduction on capital investment due to the involvement of a third-party willing to provide a leased and operated LNG FPSO.

As stated earlier, Novatek is also seeking a further cost reduction for Yamal 2 (Arctic LNG-2) by using locally fabricated modules built at a new construction yard near Murmansk, unlike the modules for the first project, which were built in China and South East Asia and shipped thousands of miles. Arctic 2 will also use gravity-based platforms, also built locally.

For the US projects, costs could possibly be further reduced by smarter interpretation of the current prescriptive codes and standards – for example, the National Fire Protection Association's Standard 59A – with a more risk-based design approach like those used in Europe and elsewhere. Experienced major international energy companies probably have greater expertise in this approach than new participants.

The use of lower-cost processes is also a possibility. An example is the use of the simpler single-mixed refrigerant – for example, the Black & Veatch PRICO process, which is currently being used on the Golar FLNG vessels as well as at some 30 small-scale LNG plants around the world. The single-mixed-refrigerant process lends itself well to prefabrication and the use of industry-standard equipment, avoiding the greater expense of bespoke plant – for example, bespoke spirally wound main cryogenic heat exchangers.

Another interesting new process technology is the use of Shell's MMLS (Moveable, Modular Liquefaction System) at Elba Island in Georgia. This consists of small 0.25 mtpa units which can be added as required to meet increasing production needs, thereby improving project cash flow. For this project, the plant will be built in two stages. Smaller plants also allow phased development and improved cash flow.

The other major scheduled project is the expansion of the Qatar facilities. This is likely to provide very competitively priced LNG for several reasons:

- the availability of experienced and competitively priced construction labour from the Indian subcontinent and Asia
- substantial local infrastructure and a well-developed production site with some opportunities for optimization
- the expected low cost of the feed gas (which is essentially a by-product from the production of the more valuable gas liquids) and the likely use of existing tankage and jetties.

Another trend is to award a project to a single contractor or a joint venture, often on a lump-sum turnkey basis, which transfers the cost and schedule risks to the contractor, benefits achieved by Nigeria LNG with a similar strategy. Past projects have often divided the contracts into major packages – for example, process plant, tanks, and jetty/marine – with the owner responsible for managing the interfaces. This has required the recruitment of additional personnel who have usually not worked together before, which adds significant costs and requires time for team development. In contrast, a single contractor is likely to have experienced teams in place which can continue building experience as they move from one project to another.

However, there is a potential threat with regard to contractors' prices. With the downturn in the oil price there has been little investment in new plant and the contracting industry has been hungry for new projects. Rates are very competitive, not only for contractors but also for high-value equipment suppliers providing the main cryogenic heat exchangers, gas turbines, and compressors. With rising oil prices, this may change, as a surge in new refinery and petrochemical projects could lead to price increases for these components.

In summary, costs have fallen significantly for projects awarded since 2014, mainly due to careful selection of lower-cost locations and to reduced project scope. Higher costs were the norm during 2010–2014, a period dominated by ambitious projects in remote locations which produced the first three FLNG projects. As the global LNG industry prepares for a new cycle of liquefaction investments, an increased focus on cost reduction will be needed to ensure that the competitiveness of natural gas is maintained in different market sectors. Further cost reductions are very probable, with all stakeholders challenging current design codes, taking advantage of repeat designs, considering new enabling technologies such as FLNG for offshore gas fields, and awarding and managing projects in a more efficient manner. This is what is needed to maintain the delivery of LNG as a competitive fuel for the future.

NATURAL GAS AS A MARINE TRANSPORT FUEL

Chris Le Fevre

The development of natural gas as a transport fuel continues to attract considerable interest because it could lead to a significant future expansion of demand for gas, including liquefied natural gas (LNG), despite questions about the comprehensiveness and rapidity of the uptake. Gas can provide significant environmental advantages over traditional petroleum products, most notably in the use of LNG as a marine fuel, where a global limit of 0.5 per cent sulphur in fuel oil will be introduced in 2020. This topic was covered in some detail in a recent issue of the *Oxford Energy Forum* that focused on the transport sector (issue 112); this article includes the introduction to that analysis and a summary of some more recent research by the author.

Disruptive aspects

A useful starting point might be to review the characteristics of gas in transport that can be considered disruptive.

When used as a marine fuel, instead of heavy fuel oil or marine diesel, LNG typically produces lower emissions of carbon dioxide and virtually no nitrogen oxides, particulate matter, or sulphur oxides. This latter feature is particularly important in the context of the International Maritime Organization's limits on sulphur in fuel oil: 0.1 per cent in the mandated emission control areas in North America and Europe, and 0.5 per cent globally, starting in 2020. Today the limit on sulphur content is 3.5 per cent, so there could be significant disruption to traditional marine fuel supply chains impacting fuel suppliers, traders, wholesalers, and users.

The lack of particulate emissions from the use of gas in transport means that the fuel could also make an impact in the road transport sector (particularly heavy goods vehicles) with a similarly disruptive impact.

The marginal cost of gas in transport is generally lower than that of oil-based products, though the capital cost of the new vessel or vehicle may be higher – particularly if a dual-fuel option is adopted. Gas prices are increasingly linked to trading hubs, and price movements will not necessarily track oil prices to the extent that they might have done in the past; this could disrupt traditional pricing arrangements in the transport sector.

Gas in transport is a relatively new market and has the potential to disrupt the existing gas supply chain. An example of such disruption could come from new entrants introducing innovative approaches to marketing and pricing – such as by trading relatively small parcels of LNG.

The utilization of LNG in marine and land transport markets underpins and enhances a growing cryogenic supply chain that provides a realistic alternative to traditional pipeline-based distribution. Furthermore, this example of small-scale LNG can help create development models that may have increasing relevance for markets that were hitherto too small, remote, or impoverished to use gas.

Barriers

Despite these advantages, there are a number of barriers to uptake – though, as discussed below, lack of refuelling infrastructure is unlikely to be one of them. The cost of adapting existing vessels and vehicles to burn gas means that it is only a realistic option for new build. Furthermore, whilst gas is generally cheaper than oil, it is not clear is how oil product prices will adapt to the changed market dynamics. In marine transport, there is no guarantee that existing differentials will be maintained, whilst for land transport, taxation rates can make a major difference. Perhaps most importantly, gas is not a zero-carbon solution, and given the continuing pressure on the marine sector to improve its environmental footprint, ship owners may be tempted to wait for new lower-carbon options such as batteries and biofuels to emerge. The use of biogas as a source for LNG is a possibility, although there are probably more realistic and preferable biofuel options. Where there are examples of biogas in the transport supply chain – for example, cars and trucks fuelled by compressed natural gas – significant state support is necessary.

Recent insights

A recent study by the author (A Review of Demand Prospects for LNG as a Marine Fuel, OIES 2018) has confirmed that, whilst consumption of LNG as a marine fuel is certain to grow, there is still uncertainty over the pace and scale of growth. The research has also identified a number of critical points related to data, infrastructure, the most promising shipping sectors, the nature of supply contracts, and forecasts of future demand.

Data on marine bunkers suffer from discrepancies due to differences in data classification and collection methods. The International Energy Agency's global ship fuel consumption figures are based on fuel sales data. Other researchers have developed estimates of fuel consumption using satellite data which track shipping activity. These approaches yielded 2015 consumption figures of 265 million tonnes and 298 million tonnes respectively. These differences, coupled with the fact that the LNG marine market is still in its infancy, mean that any forecasts of future consumption should be treated with caution.

Infrastructure, hitherto seen as a major constraint, is unlikely to be a major factor in future. The evidence from Europe suggests that if there is sufficient market potential, refuelling capacity will be made available and will almost certainly exceed the build-up in demand capacity. This reflects several factors:

- The switch to LNG-fuelled vessels requires a relatively long lead time.
- Potential owners and operators of new-build LNG-fuelled ships are unlikely to commit to invest without clarity on how their vessels will refuel.
- Facilities can be built up incrementally to match likely levels of demand.
- Most major ports are keen to ensure they have some LNG capacity even if it is underused in the short term.

Experience to date suggests that the adoption of LNG is most likely where some critical conditions are present. The most important of these are as follows:

- The vessels operate primarily or exclusively in areas subject to the existing International Maritime Organization limit on sulphur of 0.1 per cent.
- The vessels are large, fuel costs are a high proportion of their operating costs, and they have regular and predictable journey patterns.
- Operators are also owners of their vessels.
- There is a relatively high level of vessel turnover – in other words, a high frequency of new build or major re-fits.
- There are high levels of government support for new investment favouring LNG (Norway provides a particularly strong example in this regard).

The conditions above indicate that the shipping sectors that are most likely to adopt LNG as a fuel are cruise ships, large container vessels, roll on/roll off ferries, bulk carriers, and of course LNG tankers.

Most LNG-fuelled ships will be newly built, and the capital costs will exceed those of conventional ships. Owners and operators are therefore likely to require a long-term supply contract covering both pricing and physical delivery. Pricing arrangements would typically include a fixed discount in relation to marine diesel or fuel oil. LNG suppliers which are prepared to conclude such contracts will provide an important stimulus to the market.

Most forecasts suggest that global demand will be in the range of 25 to 30 million tonnes per annum (mtpa) of LNG by 2030. This would require that, very approximately, between 2,000 and 6,000 new or converted vessels would be fuelled by LNG by then. At present there are only around 250 vessels in operation or under construction, so building a fleet of the size needed to fulfil the forecasts would be challenging. The author's research concludes that a demand level of around 15 mtpa by 2030 is a more realistic prospect. This outlook could change rapidly, however, if a number of large shipping companies were to commit to LNG. (All of these forecasts exclude LNG carriers. If all of these were to switch exclusively to LNG, this alone could represent around 17 mtpa of demand by 2030.)

To conclude, LNG is *an* answer to some of the environmental challenges facing marine transport. It is too early to say if it is *the* answer. To date only a small number of major shipping operators have made a clear commitment to new-build LNG-fuelled ships. If other large companies start to follow their lead, this will be a key indication that LNG will be a significant fuel in marine transport for the next 20 years.

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CONTRIBUTORS TO THIS ISSUE

Paul Balcombe is a Research Fellow at the Sustainable Gas Institute, Imperial College, London.

James Henderson is Director of Gas Research at the Oxford Institute for Energy Studies.

Chris Le Fevre is a Senior Visiting Research Fellow at the Oxford Institute for Energy Studies.

Martin Lambert is a Senior Visiting Research Fellow at the Oxford Institute for Energy Studies.

Stephen O'Sullivan is a Senior Visiting Research Fellow at the Oxford Institute for Energy Studies.

Anupama Sen is a Senior Research Fellow at the Oxford Institute for Energy Studies.

Brian Songhurst is a Senior Visiting Research Fellow at the Oxford Institute for Energy Studies.

Jamie Speirs is a Research Fellow in the Department of Earth Science and Engineering, Imperial College, and leads the Sustainable Gas Institute's White Paper series.

Jonathan Stern is the editor of this issue, founder of the Natural Gas Programme, and a Distinguished Research Fellow at the Oxford Institute for Energy Studies.

Claudio Steuer is a Senior Visiting Research Fellow at the Oxford Institute for Energy Studies.

Bassam Fattouh *is editor, Oxford Energy Forum and director, Oxford Institute for Energy Studies*

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THE OXFORD INSTITUTE FOR ENERGY STUDIES
A RECOGNIZED INDEPENDENT CENTRE OF THE UNIVERSITY OF OXFORD
UNIVERSITY OF OXFORD

57 Woodstock Road | Oxford | OX2 6FA
Direct Line: +44 (0)1865 889136
Reception: +44 (0)1865 311377
Fax: +44 (0)1865 310527
www.oxfordenergy.org