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Challenges to the Future of Gas: unburnable or unaffordable?

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Perhaps more than for most publications I should stress that the views expressed, and any mistakes which remain, are solely my responsibility.

Preface

In his paper 'The Future of Gas in Decarbonising European Energy Markets', published in early 2017, Jonathan Stern concluded that although the prospects for gas look reasonably encouraging over the next ten years, especially for exporters looking to replace declining indigenous production, the post-2030 outlook is more uncertain. This is because the main focus of European energy policy is decarbonisation, and within this context gas, as a fossil fuel, must ultimately be removed from the energy mix if national and regional carbon emission and temperature targets are to be met. As such, Professor Stern argued that the gas industry needs to develop a 'decarbonisation strategy' if it is to prevent a serious diminution of its role in Europe post 2030.

This second paper expands his horizons to the global gas market. He highlights the fact that many of the models which are based on a similar premise to those which focus on Europe – namely that climate targets must be achieved – see gas demand continuing to increase in many regions beyond 2030. Within this context, gas has a potentially bright future in replacing the more polluting fossil fuels, such as coal and oil. However, while acknowledging that climate change targets represent a longer-term constraint, Stern asserts that many non-OECD countries are in fact driven by a more significant, shorter-term imperative, namely the price of energy. Specifically, he reviews the gas prices paid in a broad range of geographies and concludes that many of the more optimistic demand forecasts are based on price assumptions that appear unrealistic relative to the levels that customers have been paying over the past decade.

As a result, this paper questions the logic of suppliers who are waiting for a tightening in the global gas market to encourage prices back to a level that can incentivise new investment, especially in greenfield LNG projects. A key assertion is that the disparity between the likely cost of new LNG projects and the affordable price of gas in many future growth markets will need to be closed by a focus on cost reduction by project developers, rather than by a hope that higher prices and rising demand will be sustainable at the same time.

The paper also addresses the issue of the increasing complexity of the commercial structures which are likely to be required in a changing energy economy. Gas is likely to be increasingly challenged in the power generation sector, meaning that the focus of suppliers will need to switch to the industrial, residential, and transport sectors where the customer base is more fragmented and traditional long-term contracts may not be viable. This trend is likely to be exacerbated by the fact that demand growth will increasingly be located in smaller, lower-income countries with higher credit and payment risks, presenting additional challenges to the existing gas industry financing model.

This new paper on the future of gas therefore seeks to look beyond the traditional timeframe of most industry observers, and to challenge the presumption that gas has an inevitably positive future because of its position as 'the least bad fossil fuel'. It reiterates the OIES view that the next decade is likely to be a positive one for gas, but emphasizes that the immediate challenge is for gas to remain affordable in the many non-OECD countries where the bulk of global demand growth is expected. If the industry is to maintain its growth prospects in decarbonising energy balances beyond the 2030s, key decisions as to whether and how this can be achieved will need to be taken by the start of that decade.

James Henderson

Director, Natural Gas Programme

Price Conversion Factor

Gas prices in this paper are quoted in \$/MMbtu. In November 2017, approximate conversion factors were \$1/MMbtu = €2.9/MWh = 7.5 UK pence/therm

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EXECUTIVE SUMMARY

Gas as a 'transition fuel'

For the period up to 2030, the principal threats to the future of gas (outside North America) will be affordability and competitiveness. Beyond that date – and particularly beyond 2040 – carbon (and potentially also methane) emissions from gas will cause it to become progressively 'unburnable' if COP21 targets are to be met. Regionally, and especially nationally, the picture will be very different, and this level of granularity is crucial for any kind of detailed appraisal of the future of gas. But at a global level, a 20-year horizon prior to significant decline would qualify gas as a 'transition fuel'.

Affordability, competitiveness, and costs

There are limited numbers of countries outside the OECD which can be expected to afford to pay wholesale (or import) prices of $6–8/MMbtu and above, which are needed to remunerate 2017 delivery costs of large volumes of gas from new pipeline gas or LNG projects. Prices towards the top of (and certainly above) this range are likely to make gas increasingly uncompetitive, leading to progressive demand destruction. International price benchmarks for the majority of 2016-17 were $5–8/MMbtu, creating additional demand for gas in many regions. There was less evidence of falling costs for future greenfield (pipeline) gas and LNG projects, where progress will be key to affordability.

Transition from power to other sectors

In the power generation sectors of both established and new markets, gas will increasingly struggle to compete with solar, wind, and battery storage technologies which are continuing to fall in cost and appear attractive because they provide greater employment, reduced import dependence, and lower foreign exchange costs than imported gas. Domestically-produced coal has similar attributes but much higher carbon emissions. Carbon reduction policies are likely to mean that gas will be progressively squeezed out of the power generation sector, or reduced to providing a back-up role for intermittent renewables, which will not be sufficient to remunerate new gas-fired generation investments without regulatory support (such as a capacity charge). The main exceptions are: China (and possibly India) where air quality problems may lead to large-scale replacement of coal by gas-fired generation; countries where gas can replace oil products; and where customers require 24/7 electricity supply.

Unburnable or unaffordable and uncompetitive?

In the low-price world of 2017, the major debate in the gas community is when the 'glut' of LNG will dissipate and the global supply/demand balance tighten. The unspoken assumption is that when this happens – generally believed to be around the early/mid 2020s – prices will rise somewhere close to 2011–14 levels, allowing a return to profitability for projects which have come on stream since the mid-2010s, and allowing new projects to move forward. Should this assumption prove to be correct, it will create major problems for the future of gas.

The key to gas fulfilling its potential role as a 'transition fuel' up to and beyond 2030, is that it must be delivered to high-income markets below $8/MMbtu, and to low-income markets below $6/MMbtu (and ideally closer to $5/MMbtu). The major challenge to the future of gas will be to ensure that it does not become (and in many low-income countries remain) unaffordable and/or uncompetitive, long before its emissions make it unburnable.

Introduction

The constant discussion of, and calls for, a global move away from fossil fuels means that there has never been a better time to examine the future challenges to gas in global energy markets. The overall aim of this research is to examine the proposition made by gas companies and 'advocacy' organisations in the 2010s – that gas can play a major role in the transition to decarbonised energy markets, up to (and possibly beyond) 2050, because of the carbon reduction advantages of switching from coal to gas, and the role of gas in backing up intermittent renewable power generation. In other words, the proposition that gas could be not just a 'transition' but also a 'destination' fuel for a low-carbon energy system.

The first paper in this series examined the future of gas in European energy balances.[1] A major thesis of that paper was that the policy and environmental communities had found the above propositions unconvincing. It suggested that the European gas community would need to demonstrate not just with words, but also with actions, that gas could decarbonise post-2030 to ensure a longer-term future in European energy balances.[2]

The focus of this paper is to examine the future of gas in other regions, with the main aim being to examine how the challenges for gas in (principally) non-OECD regions will differ from those in Europe, with the main criteria of difference being the importance of affordability, commercial viability, and environmental (but wider than carbon reduction) issues. The questions which this paper addresses are:

- What are the most important challenges to the future of gas and what is the timescale of these challenges?
- Aside from regional and global projections, are there typologies of national gas markets which help us to identify the countries which may be particularly important to the future of gas?
- What do the answers to these questions mean for new gas exploration and development and international pipeline and LNG projects?

This paper is structured in seven sections: the first section summarises the conclusions of, and looks at the responses to, the first paper on Europe. This is followed by a section on modelling projections and scenarios for global and regional gas demand. The third section looks at wholesale gas pricing and affordability in different regions and countries for the period 2005–16. This is followed by sections on: affordability and future demand potential; supply potential and the costs of new pipeline and LNG projects; and the increasing complexity of the commercial gas framework. The final section draws some conclusions on these future challenges.

Like its predecessor, this is a short paper which deals with a very large subject and is aimed at developing general propositions about the future of gas, drawing on detailed research published by the OIES Gas Programme and others.

[1] Stern (2017).
[2] To be specific, that *methane* could decarbonise, in order to make the distinction between natural gas and other gases.

1. The Future of European gas: summary, responses, and a dilemma

Summary

The previous paper found that, if countries are to meet the carbon reduction targets to which they committed at COP21, European gas demand is likely to remain flat or decline modestly up to 2030 and decline at an accelerated rate thereafter, as the power sector will be required to decarbonise rapidly, followed by the heat sector at a slower (but still significant) pace up to 2050.

The problems encountered by the gas community over the past decade were summarised under five headings:

Commercial: the decline in energy and gas demand (which reversed only in 2016). The high-price period (2011–14) gave gas an image of being 'unaffordable' in many countries, certainly in relation to coal given the lack of a meaningful carbon price. Problems with long-term oil-linked contracts required renegotiation (and often international arbitration) to convert to hub-based prices. The market capitalisation of European utilities fell due to billions (and in some cases more than 10 billion) of euros having to be written off in power generation and gas storage assets. For upstream companies, the major problem was cost escalation and delayed start-up for new (particularly LNG) projects, which led to many being unable to cover their full costs at 2017 prices (a subject to which we return in Section 5).

Business model: the fall in market capitalisation is a major factor in the search for a new utility business model in the context of decarbonising energy markets. The key business model issue is whether low-carbon generation assets belong in the same company as fossil fuel assets. The German model of restructuring E.ON and RWE into low-carbon and fossil fuel companies (E.ON and Uniper, and Innogy and RWE respectively) has not been followed in other countries. The key questions are whether fossil-based utilities are simply in the business of managing the decline of legacy assets, or whether, even in the absence of carbon capture and storage (CCS), there can be growth in fossil generation.

Security: the third element is generally known as 'security' but is in fact a clash of political and media perceptions of gas supply security, compared with the perceptions of those focusing on gas supply and demand analysis. The political and media perception is that the principal threat to European gas security comes from Russia. This perception is strongly related to political antipathy towards the Russian Federation, particularly in connection to military activity in Ukraine and the annexation of Crimea, with a focus on the role of President Putin. By contrast, analysis based on future gas supply and demand sees Russia as the only possible source of additional large-scale gas supplies for Europe, after the current wave of surplus LNG supplies is exhausted (probably around the mid-2020s). Faster than expected declines in domestic European supplies (particularly in the Netherlands), combined with the failure of domestic European unconventional gas production, and a smaller than expected supply from both North Africa and the Southern Corridor, have contributed to this conclusion.

Environment: while the gas industry has portrayed itself as 'the cleanest fossil fuel' (in relation to emissions in general and carbon in particular), it is still a fossil fuel. Three specific problems have been raised in relation to environmental claims by the gas industry:

- Insufficient account of methane emissions from the gas chain – given that methane is a much more powerful greenhouse gas than carbon dioxide – may invalidate any claim to have advantages over coal.
- The claim that unconventional gas development involves greater emissions of methane, and also the use of harmful chemicals, in the hydraulic fracturing process.
- More generally, the lack of any significant progress towards widespread commercial-scale carbon capture and storage (CCS) presents a major obstacle to long-term inclusion of natural gas (or any

other fossil fuel) in decarbonising energy balances. This lack of progress can lead to the conclusion that new gas-fired generation and infrastructure can lead to carbon 'lock-in', namely, that unabated gas installations will be emitting carbon for the commercial life of their assets.[3]

Fragmentation: perhaps greater than all of the above problems has been the fragmentation of the European gas industry: from a powerful and cohesive force able to 'speak with one voice' during the monopoly era, to a community of (at least) four different groups of companies with different commercial interests following the liberalisation of gas markets. The four main groups comprise:

- Gas producers and exporters wanting to sell large quantities of methane (that they have spent a great deal of money discovering) over long time periods, if possible underpinned by long-term contracts;
- Gas suppliers and traders supplying power as well as gas. Unless they are affiliates of producing or exporting companies they could phase out gas and focus simply on their power business;
- Gas network companies wanting to prolong the life of their assets which could in future transport hydrogen, biogas, or biomethane, or a mixture of those products with methane. These companies may be indifferent to the product they transport as long as they are being paid for the use of their networks;
- Owners of gas-fired power stations, LNG regasification terminals, and gas storages seeking to maximise the life of these assets. Decarbonisation of other parts of the value chain may mean these assets will be stranded, which is more serious for storage and LNG terminals than for power plants with a shorter asset life.

Responses from the gas community:

A poll conducted at the FLAME 2017 conference gave interesting responses on the issues of gas advocacy, CCS, and government policy on carbon reduction:[4]

- Responses were divided in relation to the effectiveness of gas advocacy, but a third of the respondents believed that advocacy could be convincing if CCS was adopted on a significant scale.
- Less than a quarter of respondents (down from more than 40 per cent the previous year) believed that COP21 targets would result in gas demand being higher than it otherwise would have been.
- More than 50 per cent of respondents believed that technological progress in renewables and battery storage would have a greater influence on gas demand than carbon reduction targets.
- Only 10 per cent of respondents believed that low-carbon issues would gradually fade from the political agenda; and only 16 per cent that governments would abandon their carbon commitments as 2030 approached due to the cost of achieving them.

These responses, obtained at one of Europe's biggest gas conferences, suggest that the gas industry:

- believes that gas advocacy could succeed if CCS were to be adopted on a significant scale but that …
  - its future is more immediately connected with the technological progress of renewables and battery storage and ...
  - is not cynical about decarbonisation, believing this to be a long-term policy objective which will not be abandoned by governments.

[3] Ecofys (2017).
[4] For detailed responses see Appendix 1.

Another group of responses, which is more anecdotal, relates to the progressive inability of the industry to think about, and plan for, the 'long term' (defined as beyond seven years but in most cases considerable shorter). This means that it has become extremely difficult – in an industry which had been accustomed to operating with 15–30 year long-term contracts – to plan for 2025, let alone 2050.

These responses undermine the principal recommendation of the first paper, which was for the gas community to abandon previous gas advocacy slogans [5] and adopt the mantra that 'gas can decarbonise'. Investments in biogas and biomethane are increasing and production could reach 50 Bcm by 2030, or around 10 per cent of current European gas demand.[6] But without CCS it is clear that methane cannot be decarbonised on a sufficiently large scale and, quite aside from any cost considerations, fragmentation of the gas community combined with short time horizons means there is little confidence that large-scale investment in CCS will be forthcoming on any timescale.[7]

The decarbonisation dilemma of the European gas community

As stated in the earlier paper, these findings do not signify any imminent disaster for European gas prospects. Even if gas demand does not increase, the fall in domestic production is likely to mean that, in the period up to 2030, there will be a need for significantly larger gas imports and (in some cases) more infrastructure to facilitate those imports. However, the problem for the European gas community comes post 2030 when decarbonisation, initially of power and subsequently the heat sector, needs to accelerate considerably.

The dilemma facing the European gas community is that:

- it believes that decarbonisation of energy balances is ongoing, will not be curtailed, and will not be significantly positive for gas;
- it believes that the success of gas advocacy is strongly dependent on the future of CCS;
- due to value chain fragmentation (an inability of many players to adopt a planning and investment horizon longer than five to seven years) and current costs associated with the technology, significant investment in commercial-scale CCS is very unlikely.[8]

Some of these European issues recur in the rest of this paper, but the following sections suggest that the challenges to the future of gas are somewhat different and more immediate elsewhere in the world.

[5] Specifically the 3As: 'Available, Affordable, Acceptable'.
[6] Lambert (2017).
[7] For example a Norwegian cooperation between Statoil, Shell, and Total, announced in October 2017, which appeared to immediately encounter funding difficulties. Favasuli (2017).
[8] Although a small-scale project is going ahead in the UK. Favasuli (2017a).

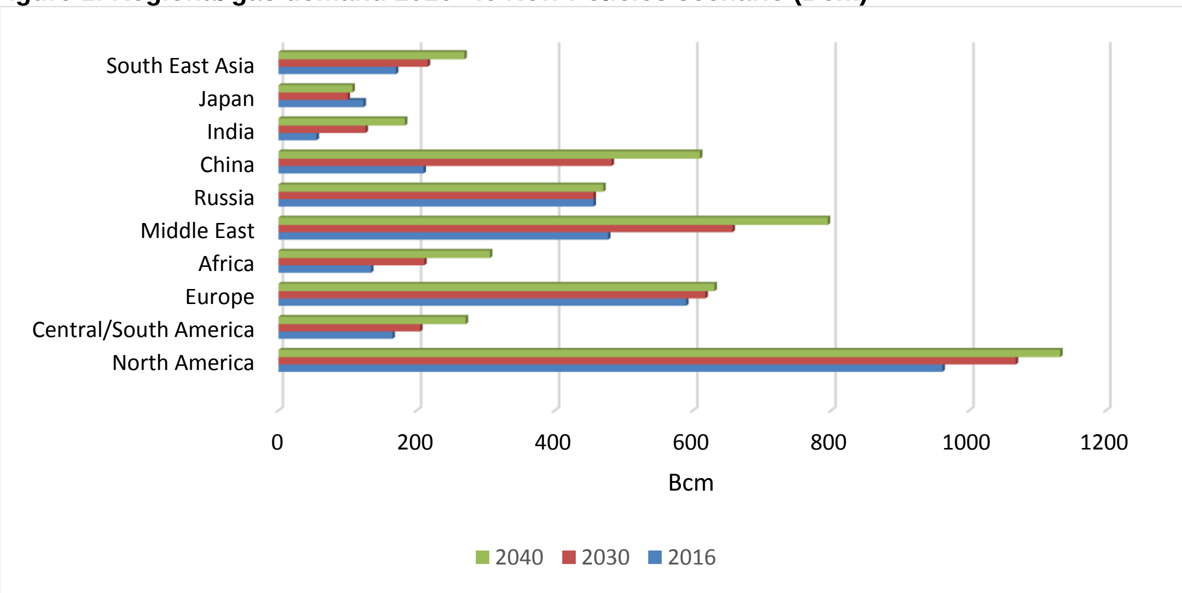
2. Regional and global modelling projections and scenarios for gas

Global energy projections, models, and scenarios being published in the late 2010s tend to divide into two categories:

- those showing how energy balances will evolve in the future, given current and anticipated future trends and policies which governments have announced;
- those seeking to demonstrate how energy balances must evolve if COP21 carbon-reduction targets are to be achieved.

In this section we look at some of the outcomes for gas in these models and scenarios. The International Energy Agency's *World Energy Outlook* (WEO) is the principal model to which we refer throughout the rest of this paper, not because it is necessarily more correct than other models, but because it provides the required degree of granularity and detail across gas supply, demand, and pricing on a regional level which is not matched by other studies. Specifically, the WEO's 'New Policies' and 'Sustainable Development' scenarios provide detailed analysis of the two categories noted above.[9] Future gas demand by region for the period up to 2040 under these scenarios is shown in Figures 1 and 2.

Figure 1: Regional gas demand 2016–40 New Policies scenario (Bcm)



Source: IEA WEO (2017), Table 8.1, p.339.

The difference between the two scenarios is relatively clear: in New Policies, gas demand increases in all regions up to 2040 with the exception of Europe, Russia, and Japan where it stabilises. But in the Sustainable Development scenario gas demand to 2040:

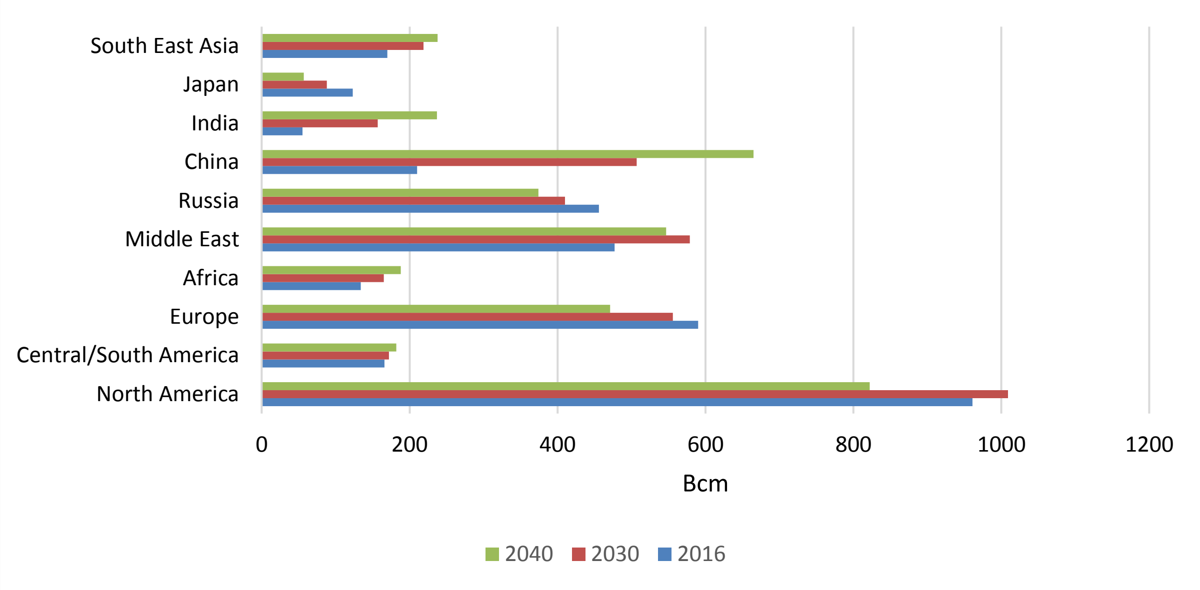
- declines significantly in Russia, Europe, and Japan;
- stabilises in Central/South America;

[9] The New Policies scenario: 'incorporates not just the policies and measures that governments around the world have already put in place but also the likely effects of announced policies as expressed in official targets and plans'. The Sustainable Development scenario incorporates three major elements: a pathway to the universal access to modern energy services by 2030; a picture that is consistent with the objectives of the Paris (COP21) Agreement by reaching a peak in emissions as soon as possible followed by a substantial decline; and a dramatic improvement in global air quality and a consequent reduction in premature deaths from household pollution. IEA WEO (2017), pp.37–8 and 727.

- increases modestly in South East Asia and Africa;
- increases but then peaks and declines post-2030 in North America and the Middle East;
- increases substantially in both China and India.

In the New Policies scenario global gas demand increases from 3.64 trillion cubic metres (Tcm) in 2016, to 4.55 Tcm in 2030, and 5.30 Tcm in 2040; in the Sustainable Development scenario the corresponding figures for 2030 and 2040 are 4.27 Tcm and 4.22 Tcm.[10] These scenarios therefore suggest that, up to 2030, the future of gas is relatively bright, but if the goals of Sustainable Development are to be met, gas demand will peak in the early 2030s and decline relatively slowly over the rest of the decade. The only rapidly growing markets over the entire period will be in China and India.

Figure 2: Regional gas demand 2014–40 Sustainable Development scenario (Bcm)



Source: IEA WEO (2017), Table 1, p.452.

International oil company (IOC) scenarios and projections have tended to show fossil fuels – and particularly gas – continuing to increase in importance. The BP *Energy Outlook* to 2035 has a base case in which gas demand is steeply rising in North America, Asia Pacific, and the Middle East, and is stable or slowly increasing elsewhere.[11] However, one of the BP Outlook's key uncertainties is the risk to gas demand, pointing out that gas growth could be challenged by both stronger and weaker environmental policies; resulting either from faster transition to low-carbon energy, or slower switching from coal to gas and lack of support for carbon pricing. An 'even faster transition' case reduces 2015–35 global gas demand growth to negligible proportions.[12]

In Statoil's *Energy Perspectives*, global gas demand increases in all three of its scenarios up to 2030, but growth in the Renewal scenario is marginal.[13] From 2030 to 2050, global gas demand increases in two of the scenarios, but under Renewal, global demand is 14 per cent below its 2014 level, with European and North American demand halving during this period and India having the only

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[10] IEA WEO (2017), Tables 8.1 and 11.1, pp. 339 and 452.
[11] BP (2017). Regional data can be found in the data tables which accompany the main report.
[12] Ibid, pp.76–85. 2.5 Bcm/year over the period, which compares with a base case of around 20 Bcm/year and a 'slower gas' case (where environmental policies are weaker rather than stronger) of 13 Bcm/year.
[13] Statoil (2017), p.38. The three scenarios are: Reform, Renewal, and Rivalry with policy and the geopolitical environment being the major differences between them.

substantial increase in demand.[14] The final observation of the gas section raises issues to which we return in later sections:

> 'The gas industry, together with national governments, must strike the balance between rising cost, affordability and sustainable energy supplies to ensure the longer term role of gas in a more diverse energy mix'.[15]

A Grantham Institute/Carbon Tracker study, which is critical of what it calls 'business as usual' studies by IOCs, tests out the consequences for fossil fuel demand of applying current cost projections for solar PV and growth of electric vehicles. These are that:[16]

> 'Solar PV (with associated energy storage costs included) could supply 23% of global power generation in 2040 and 29% in 2050, entirely phasing out coal and leaving natural gas with just a 1% market share;
>
> Electric vehicles (EVs) account for approximately 35% of the road transport market by 2035. By 2050, EVs account for over two thirds of the road transport market.'

It concludes:

> 'Lower energy demand reduces natural gas demand growth across all sectors, but it is only in our most bullish "Strong PV/Low EV" scenario that we see natural gas demand peak in 2030 and fall thereafter'.[17]

For our purposes, one of the study's most pertinent observations is:

> 'In essence, the degree to which natural gas demand grows or not to 2050 could be one of the key factors that determine whether we achieve the 2 degrees C target'.[18]

Although many of these studies have scenarios which see a fall in demand post-2030, the only substantial modelling study located by this author which has what might be described as a 'catastrophic' outcome for gas by 2050 is Greenpeace's 2015 *energy [r]evolution* in the form of the Energy [R]evolution (E[R]) and the Advanced [R]evolution (ADV E[R]) scenarios.[19] Under the Energy [R]evolution scenario:

- Global gas demand in 2030 is above its 2012 level; even in 2040 it is only 16 per cent below its 2012 level, but by 2050 it has fallen to 42 per cent of that level.
- Consistent with that pattern, in North America, OECD Europe, Europe/Eurasia and OECD Asia, Latin America, and Africa, demand does not increase greatly and falls post-2030, but not substantially until the 2040s. In the Middle East, demand is robust throughout the period. Only in China and India, does demand increase significantly, peaking around 2040 and falling slightly thereafter.

The Advanced [R]evolution scenario requires fossil fuels to be phased out almost completely by 2050 and for that reason gas demand is reduced to negligible proportions by that date:

- Global gas demand in 2030 is very similar to E[R] and is 5 per cent above its 2012 level; by 2040 it is 30 per cent below its 2012 level, and in 2050 it has dropped to 7 per cent of that level;

[14] Ibid, p.56.
[15] Ibid, p.44.
[16] Grantham Institute/Carbon Tracker (2017), p.3.
[17] Ibid, pp. 28–9.
[18] Ibid p.28.
[19] Greenpeace (2015). Energy [R]evolution (E[R]) is a 2 degrees C scenario (similar to the IEA's 450 scenario which was the Agency's 2 degree scenario previous to WEO 2017) with the additional aim of phasing out nuclear energy. Advanced [R]evolution (ADV E[R]) 'needs much stronger efforts to transform energy systems of all world regions towards a 100% renewable energy supply … a much faster introduction of new technologies leads to a complete decarbonisation of the power, heat and especially the transportation sector'.

- Regional demand follows a similar pattern, but is more resilient across Asia than in other regions up to 2040.

The conclusion of the overview of models and scenarios presented here[20] is that *from a carbon reduction perspective* the future of gas is relatively robust up to 2030, but uncertain thereafter depending on the region under consideration and the speed of decarbonisation. Aside from the Greenpeace scenarios (especially Advanced [R]evolution), the consensus is that global gas demand is unlikely to decline *significantly* until after 2040, although in some regions the decline could start soon after 2030. From a global perspective, a 20–25 year horizon prior to significant decline could be viewed as an acceptable definition of gas as a 'transition fuel'.

Modelling consensus is not necessarily a good guide to the future. Technological advances and policy discontinuities in the power sector may continue to disadvantage gas in energy balances. To the extent that renewables with battery storage achieve further substantial reductions in costs, the role of fossil fuels – and particularly higher-cost imported gas and LNG – could become further marginalised in power generation. Changes in government policies to accelerate carbon reduction policies – which the IEA refers to as 'disjointed transition' – could have a similar impact.[21]

The focus of the majority of all current energy studies is to illustrate the constraints that carbon (and other greenhouse gas) emissions impose on fossil fuel use over the next several decades. Given the consensus of 196 parties at the 2015 COP21 Paris conference, this is completely understandable. But the major proposition of this study is that other factors may be more important (and significantly more immediate) constraints on gas demand; the most important of these constraints is the affordability of the fuel in relation to the development and delivery costs of pipeline gas and LNG in the late 2010s.

[20] We have focused here on energy models, not on studies which make the assumption that natural gas (and other fossil fuels) must be phased out to meet targets. See for example Anderson and Broderick (2017), p.3. which concludes that, 'By 2035 substantial use of fossil fuels, including natural gas, within the EU's energy system will be incompatible with the temperature commitments enshrined in the Paris Agreement'.

[21] The impact of disjointed transition on global gas demand is that it follows the New Policies trajectory up to 2030 and then falls sharply, joining the Sustainable Development trajectory in 2035. IEA WEO (2017), Figure 11.8, p.464.

3. Wholesale gas prices and affordability

For the purposes of this study, a global or regional approach with timescales up to 2050 tends to obscure the question of whether it is possible to identify individual countries which may hold the key to the future of gas over the next two decades. The major focus and context of the models and scenarios discussed above, and of the previous European study, was carbon reduction. While carbon reduction policies are by no means unimportant outside Europe, in many countries and (despite the Nationally Determined Contributions (NDCs) entered into as a result of COP21) access to affordable energy (including gas) supplies is much higher up the immediate political, economic, and energy agenda.[22]

Definition and relevance of affordability

We suggest that in relation to gas, countries fall into two categories of affordability:

- An absolute price level, such as $5/MMbtu, above which customers in a country cannot afford to purchase the fuel either because of their income level, or because the end-user price level of the final product (especially electricity) for which gas is being purchased would be too high.
- A competitive price level above which customers in a country will purchase (or switch to) a competing fuel (such as coal or renewables), or will invest in demand-side measures to avoid purchasing the fuel.

In practice, anywhere there is a competitive fuel these two definitions may overlap.

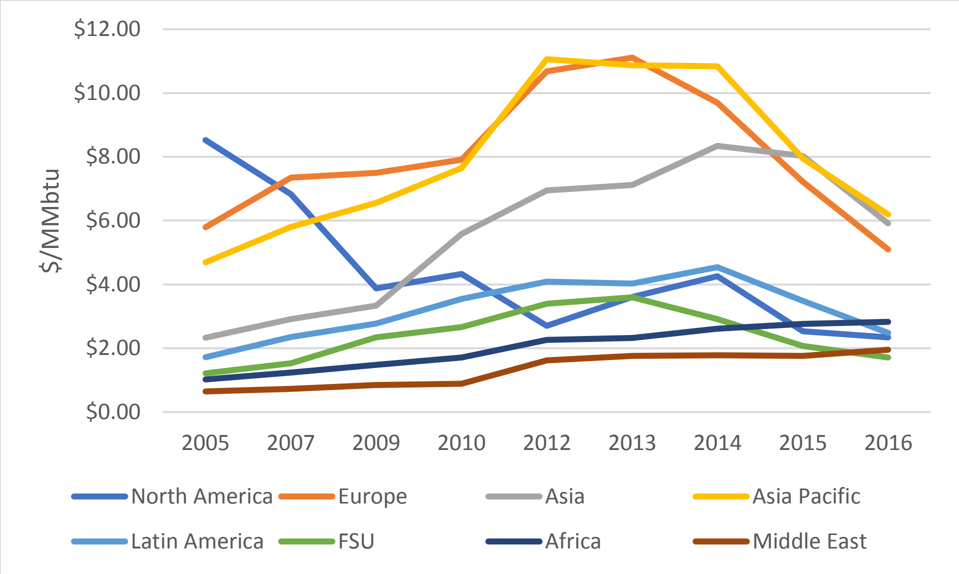
Three problem areas for gas which were identified in the European study were: economic and commercial, security, and environment.[23] Economic and commercial problems centre on costs and prices, as well as on the creditworthiness of buyers and therefore on the commercial viability of projects. Cost inflation of pipeline and LNG projects was identified as a problem for upstream companies in relation to Europe, but it is a much more serious problem for the future of gas in countries where affordability is lower, and gas is delivered to entire classes of customer at prices which do not cover the cost of delivery of domestically produced and (especially) imported energy supplies.

Regional and national wholesale gas prices 2005–16

Figure 3 shows data for wholesale prices of gas by region for the period 2005–16, from which it can be seen that, aside from Europe, Asia Pacific, Asia (post-2009) and North America (before 2009), the price of gas has seldom approached $4/MMbtu and, in most other regions, has been significantly below that level.[24] This presents a clear differentiation between what could be deemed the historically 'high price' regions (Europe, Asia Pacific, and, since 2010, Asia) and 'low price' regions (Latin America, former Soviet Union, Africa, and the Middle East).

[22] NDC submissions can be found at: 'INDCs as communicated by Parties', http://www4.unfccc.int/submissions/indc/Submission%20Pages/submissions.aspx.
[23] The other two problem areas in Europe – business models and industry fragmentation – play a less important role in regions which have either not privatised and liberalised, or where the gas industry has never established a large-scale presence in energy balances.
[24] For the methodological limitations of the IGU wholesale price data see Box 1.

Figure 3: Wholesale gas price levels by region* 2005–16



*for details of the regional groups see Appendix 3.
Source: IGU (2017), Figure 1.3, p.11.

BOX 1: METHODOLOGICAL LIMITATIONS OF THE IGU WHOLESALE PRICE DATA

The principal limitations of the data in Figure 3, and subsequent figures using the IGU price survey, are that:

> 'Comparisons of wholesale price levels ... need to be treated with caution ... [as] they can cover different points in the gas chain – wellhead price, border price, hub price, city gate price – so the comparison of price levels is not always a like for like comparison' IGU (2017, p.59).

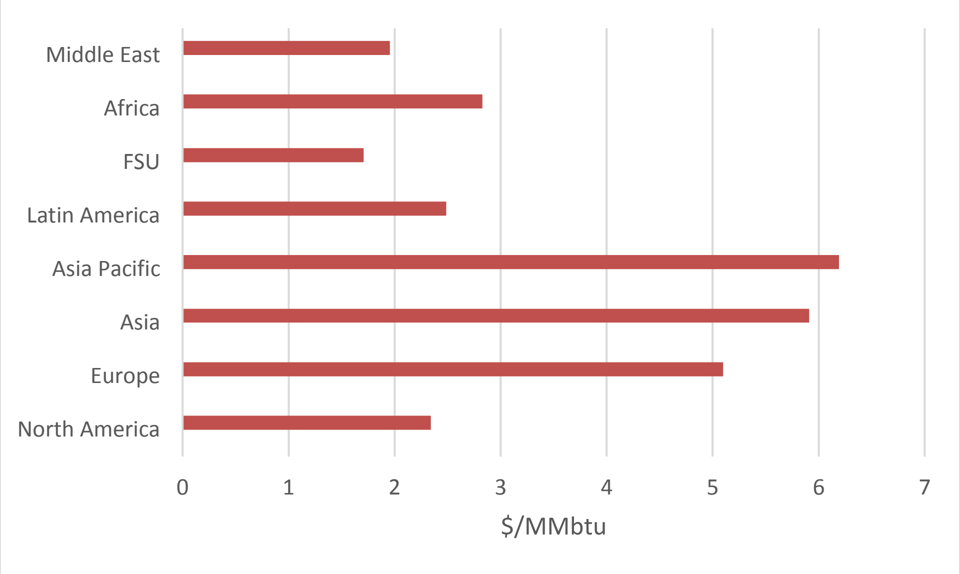
In addition, these may be prices which are charged but, in many countries, the extent to which they are paid is not certain.

The data are current prices for respective years quoted at current exchange rates. Hence, for example, the sharp decline in FSU prices post-2013 can be largely explained by the rapid depreciation of the ruble against the dollar.

For these reasons, price levels are not a completely accurate measure of affordability measured consistently across (or even within) regions. Nevertheless, Figure 3 provides a strong indication of long-run affordability – namely prices which markets could afford to pay for domestically-produced or imported gas over the past decade.

The Asia Pacific region has demonstrated sustained price levels in excess of $8/MMbtu for most of the period shown in Figure 3, with the exception of the mid 2000s and the post-2015 period. These countries mostly link gas – and specifically LNG import – prices to oil prices and this is reflected in the high levels of the 2010–14 period. Figure 3 shows that Asia is the only region to have moved from low to high prices during this period. All other regions: Latin America, the Middle East, the former Soviet Union, and Africa have sustained price levels below $4/MMbtu.

Figure 4: Wholesale gas prices by region in 2016



Source: IGU (2017), Figure 4.2, p.33.

Figure 4 shows the same data for 2016 which, more starkly than the historical series, illustrates that only in the regions of Asia, Asia Pacific, and Europe were wholesale prices significantly above $3/MMbtu. However, these regional figures involve averaging of data for significant numbers of countries and it is therefore important to look at the price series for individual countries within a region.[25]

Evolution of wholesale gas prices in different regions

This section provides a more detailed overview of the evolution of wholesale gas prices in individual countries over the period 2005–16. **North America** is perhaps the least representative of all regions, with high prices in the early/mid 2000s and low prices thereafter, due to the shale (oil and) gas revolution which, since the late 2000s, has created a 'Golden Age of Gas' – the only region where this has happened.[26] Henry Hub prices fell from double digits in the early 2000s to less (and for periods very substantially less) than $4/MMbtu for most of the 2010s. Because of the integration of the region's markets via cross-border pipelines, and the liquidity of these markets, prices remained within a relatively narrow range (Figure 5). Scenarios from the US Energy Information Administration's *Annual Energy Outlook 2017* indicate that Henry Hub prices will not rise substantially above $4/MMbtu for the next two decades.[27] North America may be the only region which appears to have domestic gas supply availability at these price levels for decades into the future, but the USA and Canada have the capacity to pay much higher price levels (as evidenced by the early to mid-2010s) should prices rise significantly higher than $4–5/MMbtu.[28] Less clear is the position of Mexico, which has benefited from imports of low-cost US pipeline gas, but where affordability at higher prices is less certain.

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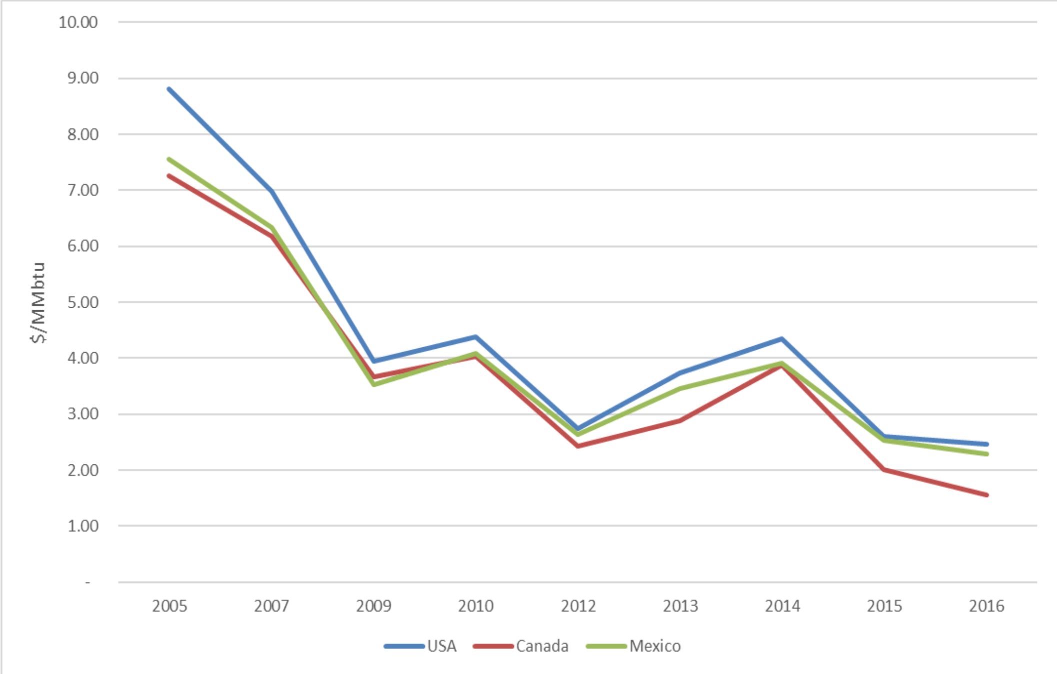
[25] For definitions of the IGU regions see Appendix 3.

[26] For comments on the IEA's Golden Age of Gas hypothesis see: IEA WEO (2017, Box 1, p. 337); Stern (2017); and Boersma and Jordaan (2017).

[27] Three of the five scenarios in the Annual Energy Outlook presentation (Slide 27) by the EIA Administrator Sieminski (2017) in January 2017 suggested that prices will be at or below $5/MMbtu until 2040.

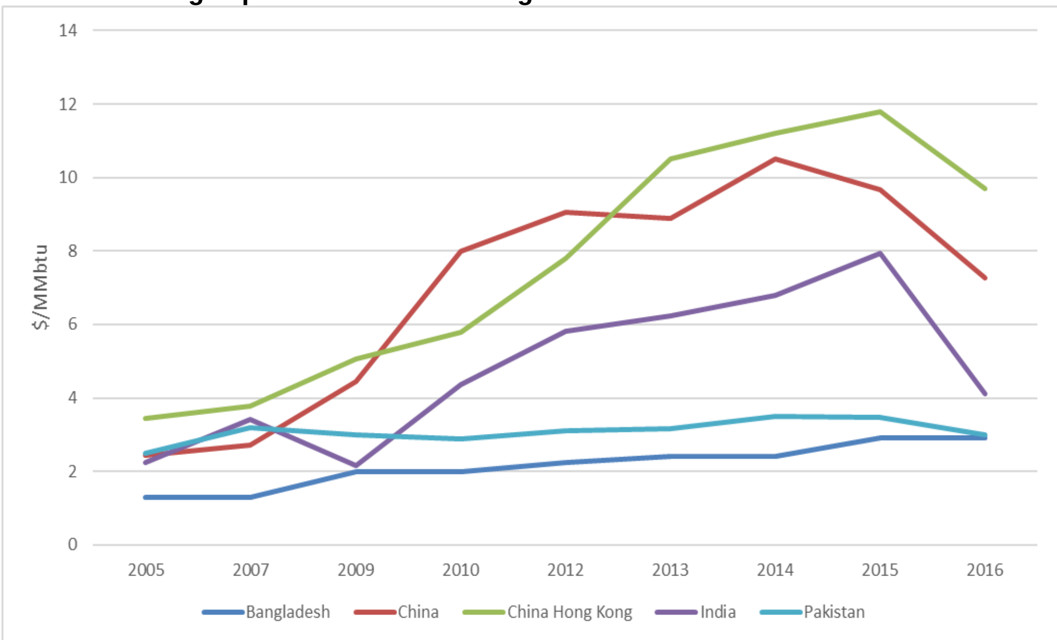
[28] Other countries and regions such as Russia, Central Asian, and some Middle East countries such as Qatar may be able to maintain similar production costs, but none have proved able to pay substantially higher prices on any sustained basis.

Figure 5: Wholesale gas prices in North America 2005–16



Source: IGU (2017).

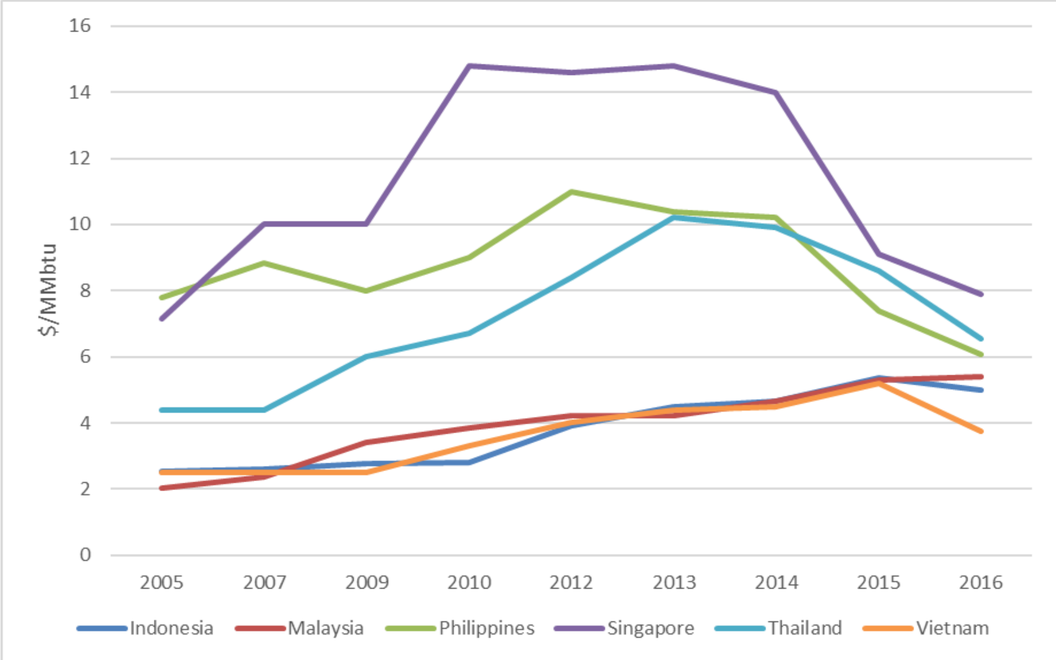
Figure 6: Wholesale gas prices in five Asian region countries 2005–16



Source: IGU (2017).

Figure 6 shows prices in five countries in the **Asian** region. While prices in Bangladesh and Pakistan have mostly been significantly below 4/MMbtu, and Indian prices collapsed to that level in 2016, prices in China and Hong Kong have been in the $8–10/MMbtu range since the early 2010s.

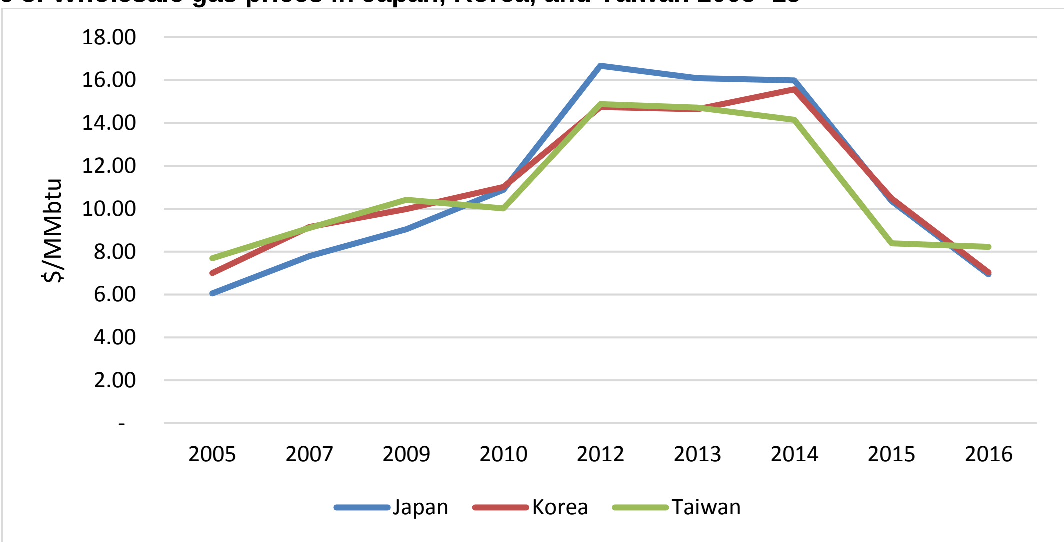
Figure 7: Wholesale gas prices in six Asia Pacific region countries 2005–16



Source: IGU (2017).

Figure 7 shows that prices in Singapore, the Philippines, and (since 2009) Thailand have been significantly higher than in the other **Asia Pacific** countries, although in 2016 there was considerable convergence.

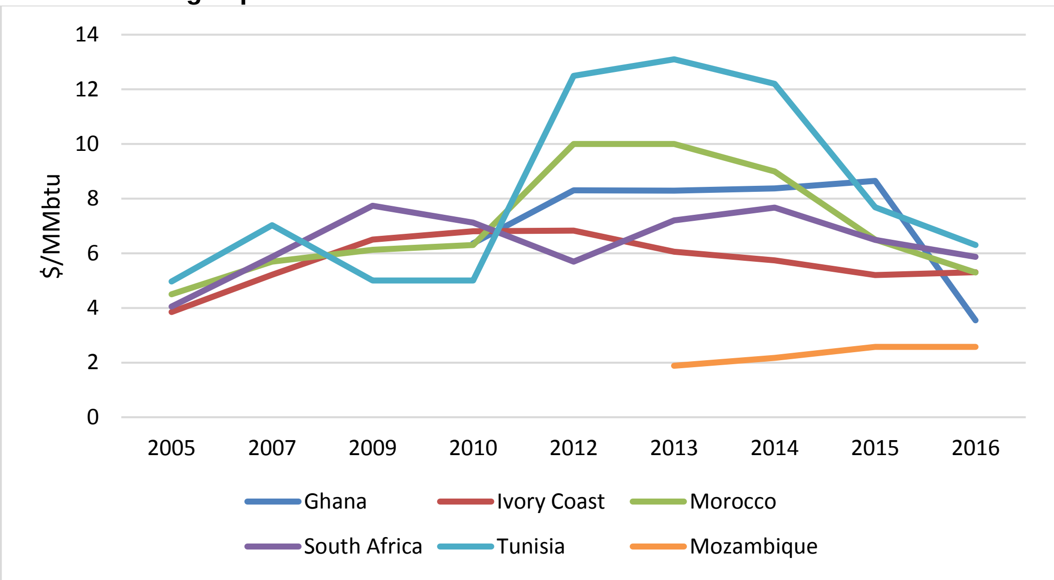
Figure 8: Wholesale gas prices in Japan, Korea, and Taiwan 2005–15



Source: IGU (2017).

With a few exceptions, Figures 6 and 7 contrast sharply with the prices for Japan, Korea, and Taiwan in Figure 8. These countries have little or no domestic gas production and therefore LNG imports set the wholesale price. Price levels in the period 2010–14 were partly due to nuclear power station closures (particularly in Japan), and partly to the very high oil price levels to which LNG prices were contractually linked.

Figure 9: Wholesale gas prices in six African countries 2005–16

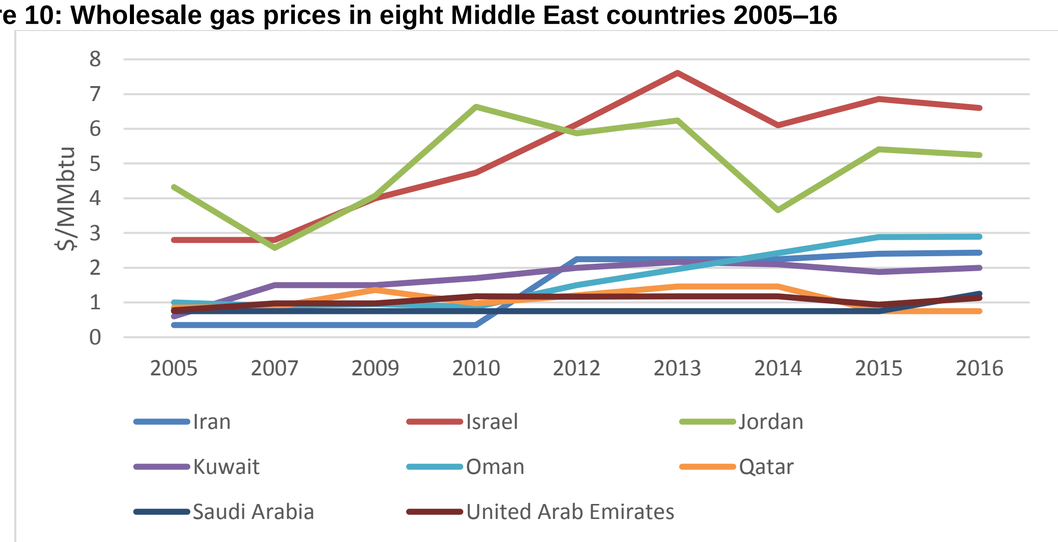


Source: IGU (2017).

Five of the six **African** countries shown in Figure 9 have paid prices in the range of $4–12/MMbtu during the period: Tunisia, Morocco, Ivory Coast, South Africa, and Ghana (since 2010). Elsewhere in Africa, prices have remained below (and in many cases far below) $4/MMbtu, although by 2016 prices had been raised much closer to this level in Egypt and Cameroon.

Of the eight **Middle East** countries in Figure 10, Israel and Jordan stand out with significantly higher gas prices than the Gulf countries, which are all below $3/MMbtu for most of the period. However, prices in Gulf countries do not reflect affordability levels, for reasons which are discussed in Section 4.

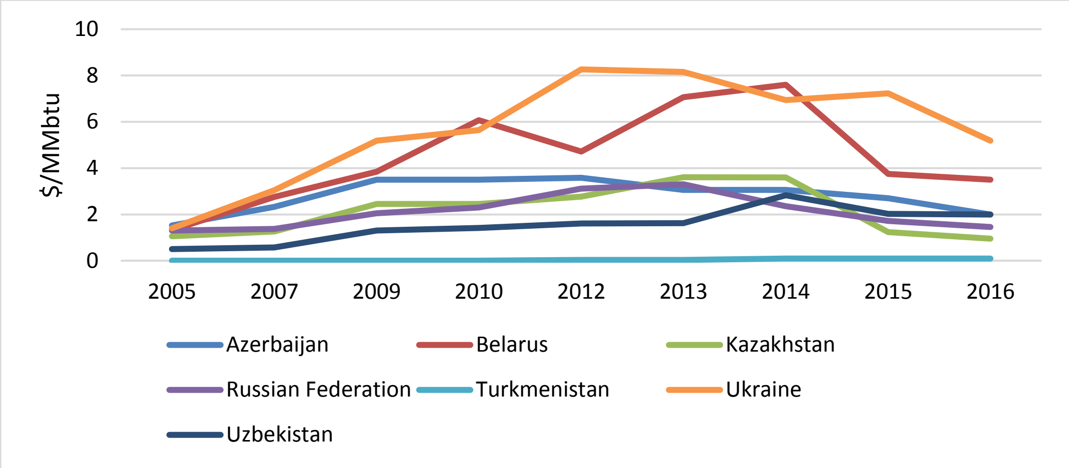
Figure 10: Wholesale gas prices in eight Middle East countries 2005–16



Source: IGU (2017).

Of the seven countries of the former Soviet Union in Figure 11, Belarus and Ukraine stand out with significantly higher gas prices in the 2010s than other countries, which are all substantial producers and exporters. As mentioned above (Box 1), the sharp decline in Russian prices post 2013 is mainly due to the depreciation of the rouble against the dollar.

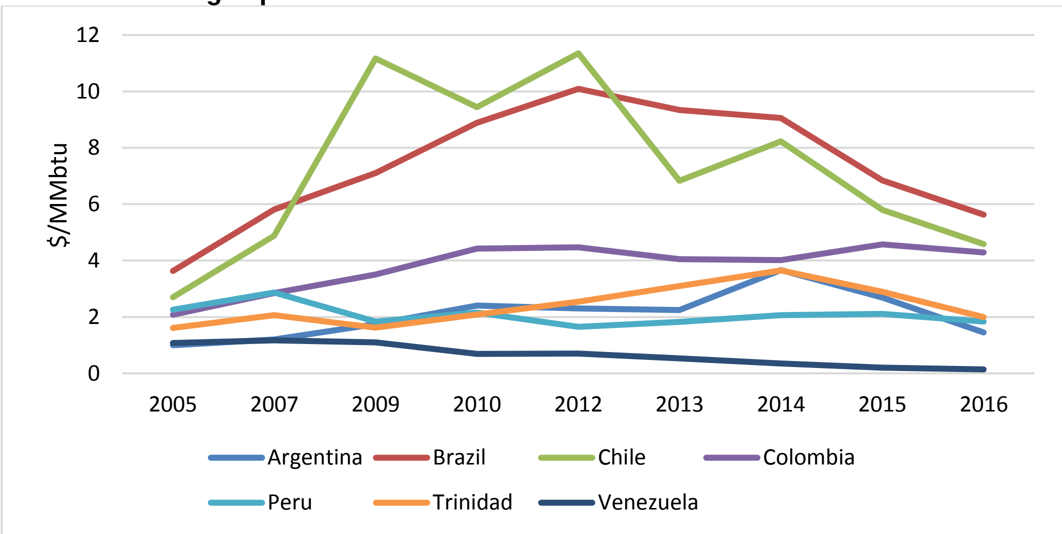
Figure 11: Wholesale gas prices in seven countries of the Former Soviet Union 2005–16



Source: IGU (2017).

Of the seven **Latin American** countries in Figure 12, Brazil and Chile had significantly higher gas prices for most of the period, although they converged with Colombian prices in the mid-2010s, while in Peru, Trinidad, Argentina, and Venezuela prices remained substantially below $4/MMbtu.

Figure 12: Wholesale gas prices in seven Latin American countries 2005–16



Source: IGU (2017).

4. Affordability and future demand potential

Individual country criteria and the contrast between China and India

Table 1 shows countries in terms of population, GDP per capita, and share of gas in primary energy demand (PED) (2016 figures), together with wholesale price levels for the period 2005–16. Countries where gas has a potentially bright future are those with relatively large populations, where the fuel comprises significantly less than 20 per cent of primary energy demand, and where there is a proven ability to pay prices sufficient to remunerate the development and delivery of LNG and pipeline gas imports. Those in the first two categories which have demonstrated the ability to pay wholesale prices of $8/MMbtu and above are: China, the Philippines, Thailand, Brazil, Chile, Tunisia, Morocco, and Ghana. If we include countries (in the first two categories) with prices which have ranged from $4–8/MMBtu, then we can add: India, Ivory Coast, South Africa, Indonesia, Vietnam, and Colombia. The possibility that countries with smaller populations (or those where the share of gas is already in excess of 20 per cent of primary energy demand) could still have significant potential for increased gas demand is not excluded, but the case may be harder to make. The scale of demand expectations is clearly different between Asian countries with large populations (such as China) and African countries with smaller populations and much lower per capita GDP levels.

But country-level generalisations, particularly for large countries, do not capture the granularity of individual regions, sectors, and industries which may be willing and able to pay much higher prices than the average, particularly for a constant supply of energy. This will particularly be the case for major regions or cities with a higher per capita GDP level than the country average, or where export-oriented industries are located. An additional question is then whether these gas demand 'niches' of 1–2 Bcm in countries such as Ghana, Ivory Coast, and Morocco – despite being located in countries with relatively low per capita GDP – could in time grow into significantly larger, higher-price, gas markets.

China and India provide an interesting contrast in relation to affordability and price reform. They are both countries with populations in excess of 1.3 billion, where gas is significantly less than 10 per cent of primary energy demand. Hence they are both high priority targets for those seeking markets for large volumes of gas.[29] Projections of Chinese gas demand (Figures 1 and 2) show that this could increase by 270–290 Bcm by 2030 and by 400–450 Bcm by 2040, compared with 210 Bcm in 2016.[30] Chinese regulated city gate gas prices range from close to $9/MMbtu in Shanghai to less than $4.50/MMbtu in Xinjiang (western China); prices in the majority of the eastern provinces are in excess of $8/MMbtu.[31] From November 2016, the National Development and Reform Commission (NDRC) has allowed city gate prices to fluctuate within a range of plus or minus 20 per cent from the regulated price level, meaning that prices in many eastern provinces have been in excess of $10/MMbtu. In some respects, these regulated prices are problematic, given their inflexibility and slowness to respond to fluctuations in international price levels, and this may have been partly responsible for the fall in gas demand growth rates in 2015/16. In another context, they can be regarded as providing incentives for domestic Chinese producers to continue development of high-cost (especially unconventional) production.

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[29] By 'large' is meant volumes in excess of 10 Bcm/year. This contrasts with other markets with much more limited demand potential.

[30] For detailed discussion of Chinese gas demand see: Peng, D. 'Prospecting Chinese gas demand', in OEF (2017a), pp. 23–27.

[31] Prices from NDRC (converted at $1 = RMB6.5) which had remained unchanged from 2015, were lowered in September 2017. Interprovincial transmission tariffs and VAT on gas were reduced at the same time.

Table 1: Non-OECD countries* with significant future gas potential, 2016

	Wholesale prices representative of the period 2005–16			Gas Demand (Bcm)	Gas as % of PED	Population (mill)	GDP/Capita US $ 2017
	HIGH	MEDIUM	LOW				
	>$8MMbtu	$4–8/MMbtu	<$4/MMbtu				
China	X	X		207.2	6	1,379	8580
China HK	X	X		3.6	10	7	45000
India		X		54.4	6	1,324	1850
Pakistan			X	40.6	49	193	n.d
Bangladesh			X	29.4	77	163	1530
Singapore	X	X		12.0	13	6	53880
Philippines	X	X		3.8	8	103	3020
Thailand	X	X		48.1	15	69	6340
Malaysia		X	X	44.9	39	31	9660
Indonesia		X	X	43.2	8	261	3860
Vietnam		X	X	11.3	15	83	2310
Tunisia	X	X		5.9	46	11	3520
Morocco	X	X		1.2	5	35	3180
Ivory Coast		X		2.1	13	24	1600
South Africa		X		5.3	3	56	6090
Ghana	X	X		1.3	11	28	1610
Israel		X		9.6	33	9	39970
Jordan		X		2.9	23	9	5680
Iran			X	188.3	67	80	5250
Kuwait			X	21.4	53	4	27240
Oman			X	26.1	84	4	17410
Qatar			X	49.1	76	3	60810
Saudi Arabia			X	90.0	37	32	20960
UAE			X	74.2	61	9	37350
Argentina			X	54.3	50	44	14060
Brazil	X	X		35.3	11	208	10020
Chile	X	X		4.9	11	18	14310
Colombia		X		11.4	23	49	6240
Peru			X	8.2	28	32	6600
Trinidad			X	20.7	89	1	14780
Venezuela			X	22.8	43	32	6850
Mexico		X	X	89.5	43	128	9250
Belarus		X		19.0	63	10	5590
Ukraine		X		31.5	29	45	2460

*Chile and Israel are OECD Member States; Figures in red are for 2015.

Sources: BP (2017a, pp.9 and 29); IEA (2017a, Table 5, pp. II.8–9); IEA (2017b, pp.166, 193, 219, 251, 269, 313, 337, 359, 363); population, total, World Bank Database http://data.worldbank.org/indicator/SP.POP.TOTL; GDP per capita, current prices, International Monetary Fund Data Mapper, www.imf.org/external/datamapper/NGDPDPC@WEO/OEMDC/ADVEC/WEOWORLD/AFG/AUS/OEMDC/ADVEC/WEOWORLD/AFG/AUS?year=2017.

However, despite continuing tariff anomalies between provinces, and slow progress in liberalisation of access to infrastructure, Chinese gas price reform has moved significantly towards market pricing during the 2010s.[32] It has also been consistent with environmental policy and urban air quality improvement, which is particularly important for the winter months when heating demand rises dramatically and substantially more gas is needed to substitute for coal. These reforms have also signalled that, at least in the eastern part of the country, affordability levels are high enough to support the costs of delivery from new international pipeline and LNG projects.[33]

This provides a significant contrast to India, where gas demand is projected to increase by 70–100 Bcm in 2030 and 128–175 Bcm in 2040, from 55 Bcm in 2016 (Figures 1 and 2). While these increases are significantly less than the China projections, they are very substantial, and certainly important for those marketing large volumes of new gas. Figure 3 shows that wholesale prices for the Asian region were in excess of $4/MMbtu but significantly less than $8/MMbtu for most of 2010–16. However, this is an example of the difficulty of interpreting the term 'wholesale price' (see Box 1), as the price paid for domestically produced gas has never exceeded $4/MMbtu, despite the fact that a price of twice that level is estimated to be required to bring forward substantial additional supplies.[34]

A study of the competitiveness of Indian gas by sector suggests that aside from the transport sector – where compressed natural gas (CNG) is not subject to the taxation levied on gasoline and diesel – it is very difficult for gas to compete at a price in excess of $5/MMbtu; and in relation to domestic coal in the power sector that figure is $3.50/MMbtu.[35] The transport sector is important since India was one of the first countries to mandate switching to CNG in urban transportation for air quality reasons; this was applied in 11 (out of 29) states by the mid-2010s. But the main obstacle to optimism that India will increase gas demand on the scale suggested in Figures 1 and 2, is the lack of any coherent national gas price reform and seemingly less concern about air quality despite increasing problems in major cities.

Affordability and government subsidies

We have already seen that in large countries such as China, average prices may not be a guide to affordability in individual provinces, due to the specific characteristics of customers or government policies which require gas to be introduced for environmental reasons. But another important reason why these prices are not an accurate guide to affordability can be seen where governments (or government-owned utilities) have been willing to subsidise domestically produced gas and (particularly) imported gas or LNG.

Many countries (and indeed entire regions) subsidise energy, including gas, prices to certain (and in some cases to all) market sectors. Defining and measuring what is, or should be considered as, a 'subsidy' is a complex task, but for our purposes two definitions are relevant:[36]

- Prices which are lower than international trade – related to either to oil or hub – benchmarks;
- Prices which fail to cover the cost of delivery – either production or import and transportation – of gas to customers.

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[32] For an account of how Chinese gas price reform progressed from cost- to market-based pricing see Chen (2012).
[33] It is not clear whether this is true of Gazprom's Power of Siberia pipeline, due to start operating at the end of 2019. Detailed calculations depend on cost and exchange rate assumptions. Henderson and Mitrova (2015).
[34] Sen (2017), Figure 1 and pp.2–3. In October 2017, the price for gas produced from ultra-deep water was raised to $6.30/MMbtu for the coming 6 months. But this only relates to a very small share of total production and it remains to be seen whether it will be high enough to revive interest in offshore acreage.
[35] Ibid, pp.2–20 especially Figures 9–12. See also Sen, A. 'Disentangling short and long-term determinants of gas demand in India', OEF (2017a), pp.27–32.
[36] The IEA uses the following subsidy formula: Subsidy = Reference Price – End User Price, where Reference is the import parity price. IEA Website (2017) has data on subsidies by fuel and by country. An alternative definition includes the taxes necessary to offset the emissions caused by burning the fuel. Coady et al. (2015) and Parry (2016).

The categories in Table 2 give a strong indication of prices in relation to both of these definitions. Oil-related (OPE) and gas to gas competition (GOG) prices clearly relate to the first category. Bilateral monopoly (BIM) and netback from final product (NET) prices probably cover the cost of delivery but are not at international price levels. Regulated cost of service (RCS) should cover delivery costs, but these price levels almost certainly do not reach international levels. Regulated social prices (RSP) may or may not cover delivery costs, depending on how social pricing is defined. Regulation below cost (RBC) and no price (NP) by definition do not cover delivery costs.

Table 2: Regional wholesale prices by price formation mechanism 2016 (% of total consumption)

	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP
North America		100						negl
Europe	30	66			2	2		negl
Asia	69	12	negl		18	negl		
Asia Pacific	64	14	5		negl	16		negl
Latin America	26	19	4	8	5	21	17	negl
Former USSR	4	25	5		38	11	17	negl
Africa	7	11	4	3	24	2	28	negl
Middle East	3	2	15		1	75	3	1

Notes: OPE – oil price indexed; GOG – gas to gas (hub) priced; BIM bilateral monopoly pricing; NET – netback from final product; RCS – regulated cost of service; RSP – regulated social pricing; RBC – regulation below cost; NP – no price. Definitions can be found in Appendix 2.

Source: IGU (2017), Table 3.2, p.21.

Table 2 shows that in 2016, the share of gas sold at international market prices (OPE+GOG) was 45 per cent in Latin America, 29 per cent in former Soviet countries (FSU), 18 per cent in Africa, and 5 per cent in the Middle East. With 17 per cent in Latin America and the FSU, and 28 per cent in Africa having been sold below the cost of delivery (RBC), this leaves 38–90 per cent of gas in these regions being sold at a level which may be above delivery cost but was far below either international market levels or levels high enough to provide a commercial return on investment in new production.

The IEA subsidies database suggests that gas represented 24 per cent of total energy subsidies in 2015; however, for individual countries the figures can be much higher.[37] Where gas is used for power generation, electricity subsidies may also be relevant.

Table 3 shows natural gas subsidy data for those countries identified in Table 1 as having significant future gas potential.[38] Two trends stand out from Table 3: first that subsidies have generally declined over the (relatively short) period 2013–16; and secondly that some of the largest gas subsidies are found in the Middle East and South Asia.

[37] IEA Website (2017).

[38] Country selection is based solely on data available in the IEA database and is not intended to suggest either that other countries in Table 1 do not subsidise or that the database is comprehensive in relation to gas subsidies.

Table 3: Natural gas subsidies 2013–15 (real 2015 billion US$)

	2013	2014	2015
Argentina	5,336.8	4,967.8	3,490.0
China	1,985.8	2,640.8	-
India	4,194.8	4,547.0	2,244.3
Iran	18,296.0	20,860.7	17,937.5
Kuwait	1,103.4	917.5	905.3
Malaysia	75.7	-	-
Mexico	1,408.0	574.0	572.7
Oman	-	1,828.7	-
Pakistan	5,991.1	4,859.3	2,592.3
Qatar	1,353.4	1,407.7	956.5
Saudi Arabia	8,099.2	6,926.5	6,695.0
Thailand	627.9	363.4	188.0
Ukraine	4,163.6	3,301.2	3,075.2
UAE	9,074.4	7,833.5	6,783.4
Venezuela	4,633.7	3,312.6	2,197.9
Vietnam	495.0	246.1	172.4

Source: IEA Website (2017).

The special case of the Gulf countries

Much of the justification for selling gas at a subsidised price (however defined) is that citizens and industries are too poor to pay the full cost of modern energy supplies. But in the case of many Middle East and particularly Gulf countries, GDP/capita data (Table 1) suggest this is clearly not correct and needs further elaboration, because the region is already a major global demand centre (around 450 Bcm in 2016) and is projected to increase to 500–800 Bcm by 2040 (Figures 1 and 2). One of the principal elements of the modern-day ruling bargain, or 'social contract', in the Gulf has been very significant subsidies on services.[39] In relation to gas, Dargin describes the 'social contract' as follows:

> 'Over the years, this social contract developed a sense of entitlement to low-priced gas with the predictable result that domestic gas prices remain divorced from modern investment criteria and certainly from international market prices'.[40]

More recent research has suggested that this sense of entitlement is weakening and is more nuanced between different social groups.[41]

But there is also a strong economic motivation for gas subsidies. Given that most Gulf countries have energy balances which are overwhelmingly oil and gas-based, and oil exports provide a very substantial share of government revenues, any substitution of gas in the domestic market which allows additional volumes of oil to be exported is not necessarily a revenue-negative policy, even if the gas is imported at much higher prices than can be charged in the domestic market.[42] This means that in countries with energy balances largely composed of oil and gas, low domestic gas prices,

[39] El-Katiri and Fattouh (2015).
[40] Dargin (2008).
[41] Crane (2016).
[42] The exact calculation will depend on (ever-changing) levels of international oil and gas prices, levels of domestic gas prices, and exchange rates.

although failing to provide incentives for efficient use, are not a true measure of affordability if the alternative fuel which would be used is oil which can otherwise be exported (or where the use of gas avoids the import of more expensive oil).

This is not an argument against raising prices in these countries, and in the post-2014 period of lower oil prices and squeezed government revenues, there have been signs of price reform on a limited scale.[43] For example, in 2016 Saudi Arabia increased industrial gas prices by 67 per cent (but only from $0.75 to 1.25/MMBtu), while the UAE has completely failed to reform gas prices. The reform programme in Iran, launched in 2010, while initially successful, subsequently foundered on inflation and exchange rate problems.[44] Unless price reform efforts significantly intensify, the trend which has seen Gulf countries (traditionally gas exporters) becoming gas importers, will accelerate.[45] Low-cost gas produced in association with oil was exhausted around the beginning of the 2000s. Non-associated gas reserves in these countries are being developed but (with the exceptions of Iran and Qatar) costs are estimated at $4–6/MMbtu, far in excess of wholesale price levels, and therefore unprofitable without government subsidy.[46]

The most likely outcome is that many of the Arab Gulf countries (with the exception of Qatar) will continue to produce gas at much higher costs, or import at much higher prices, than they can collect from domestic customers, with their governments (or government-owned utilities) funding the difference. Absent significant gas price increases to at least $5/MMbtu, with the threat of adverse political consequences for ruling regimes, the only trend which could undermine this outcome would be diversification of energy balances towards other energy sources. This is happening in some Gulf countries with the development of nuclear power, renewables, and coal.[47] But the key conclusion is that wholesale price data for many Middle East countries are not a true reflection of consumer affordability, but rather reflect complex political calculations and, because of the oil substitution effect, may allow these countries to expand their gas markets with unreformed gas pricing for many years, as illustrated by the IEA assumptions on subsidy removal:[48]

> 'In the New Policies Scenario, all net-importing countries and regions phase out fossil fuel subsidies completely within ten years. In the Sustainable Development Scenario, while all fossil fuel consumption subsidies are similarly removed within ten years in net-importing regions, they are also removed in net-exporting regions, except some countries in the Middle East, within 20 years.'

Similar subsidies are present in other regions, but generally on a smaller scale and for shorter periods of time. For example, many Latin American countries which depend substantially on hydropower, rely on back-up fuel for generation in years when there is insufficient rain. Previously this tended to be diesel, but in many countries this has been replaced by gas-fired generation based on imported LNG.[49]

But for many less developed countries, affordability without government subsidies remains very low. For example, in Mozambique, it has been reported that new gas producers will need to offer gas to

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[43] A collection of articles reviewing price reforms in the MENA region and the conflict with the social contract can be found in OEF (2017).

[44] For details see the contributions of Rentschler and Kornejew, Boersma and Griffiths, and Bazoobandi in ibid. Background to these more recent developments can be found in Darbouche (2012) and Hassanzadeh (2014), Chapter 5.

[45] Earlier, Iran, UAE, and Oman became importers of pipeline gas from the region; while Kuwait and Dubai (soon to be followed by others) are importing LNG. The history and details of how these developments unfolded in individual countries across the MENA region can be found in Fattouh and Stern (2011).

[46] There is a similar situation in North Africa, in particular Algeria which is an important gas producing and exporting country, see Aissaoui (2016).

[47] For example: Gomes, I, 'Natural Gas Demand in the Middle East: trends and issues', in OEF (2017a), pp. 32–35. See also: Apicorp (2017), Poudineh et al. (2016), El-Katiri (2012), (2014), and (2017).

[48] IEA WEO (2017), p.47.

[49] For an overview of individual Latin American countries and the continent see Honoré (2016) and Honoré et al. (2016), pp. 385–421.

the domestic market at a price below $2.64/MMbtu – a figure which is consistent with the IGU wholesale price for 2016 shown in Figure 9 – if the projects are to move forward.[50] The Nigerian gas masterplan needs a domestic price of at least $4/MMbtu to be commercially viable compared with 2016 prices of $3/MMbtu.[51]

Environmental issues: air quality, methane emissions and carbon lock-in

One of the major arguments in favour of gas has been related to its environmental advantages. In many countries, an immediate contribution can made be to air quality, particularly in urban environments impacted by the burning of coal and biomass.[52] While relevant in countries such as China and India, this argument cannot be pursued too far, given the properties of modern coal-fired power plant which resolve many of the air quality (although not the carbon emission) problems at lower cost than imported gas, particularly if based on domestic coal.[53] Arguably, the air quality advantages of gas have been overly focused on switching from coal in power generation. A survey of energy and air pollution makes clear that there are serious problems caused by other fuels in power generation and also in the industry, buildings, and transport sectors.[54] Air pollution from the transport sector is a major problem in cities around the world. The extent to which gas can contribute in this sector is unclear, but switching from liquids to gas (CNG or LNG), particularly as a marine fuel, is seen as more promising than for road vehicles, although in individual countries (particularly in the Middle East and Eurasia) the potential in that sector should not be ignored.[55]

As far as greenhouse gas emissions are concerned, the introduction noted that gas advocacy initiatives have been based largely on the advantage of lower carbon emissions than for other fossil fuels. Challenges to this claim were discussed in the first paper in relation to methane emissions, but since then attention to this issue has increased.[56] Data on methane emissions are extremely problematic, and calculations of greenhouse gas potential are complex. It is very difficult to separate methane emissions of upstream gas operations from those of oil and, given that nearly 80 per cent of emissions from these sectors is estimated to take place in upstream operations, this is clearly a key issue. Despite the fact that methane emissions from the coal sector are estimated as being similar to those from the gas sector, this is rarely mentioned when the greenhouse gas emissions from the two sectors are compared.[57] Some of these complexities and available data are outlined in Appendix 4.

The industry response to the lack of data on methane emissions has been relatively muted, with the reasons given being complexity, expense, and the difficulty of obtaining agreement across a number of companies. These arguments are neither adequate nor convincing; they lead to suspicions that either the industry does not know its emissions and is not interested in finding out, or that it does know and is hiding very high estimates. While there are a number of initiatives to improve the situation, national and international industry bodies urgently need to put in place reporting requirements for the different sections of the value chain in each country – upstream, high-pressure

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[50] Elston, L. 'Mozambique's downstream projects need cheaper gas', *Interfax Gas Daily*, 26 July 2017, pp. 1–2.

[51] IGU (2017), Figure 4.3, p.34.

[52] For a comparison of the shares of fuels in total emissions of particulates, sulphur dioxide, nitrogen oxide, and carbon dioxide see IEA WEO (2017), Figure 10.1, p.401; Henderson, J. 'Coal-to-gas switching: air pollution rather than carbon may be the key catalyst', in OEF (2017a), pp. 51–55.

[53] For example, in some South East Asian countries where the power generation sector is moving from gas to coal. IEA (2016), pp.215–8.

[54] Mexico provides an example where emissions from oil were the most important source of air pollution from the power generation sector in 2015. IEA (2015), Figure 5.2, p.145.

[55] The IEA is relatively pessimistic about the potential of gas as a marine fuel with only 51–57 Bcm of demand (significantly less than 10% of global bunker fuel demand) in 2040. IEA WEO (2017), Table 2.1 and Figures 8.1 and 11.1, pages 65, 339 and 425; LeFevre, C. 'The demand for gas as a transport fuel', in OEF (2017a), pp. 48–51.

[56] Stern (2017).

[57] IEA WEO (2017), p. 414 and 417 estimates methane emissions from oil and gas at 76 mt and those from coal at 40 mt in 2015. Gas alone accounted for 42 mt of which 60% was vented, 35% was fugitive, and the rest was due to incomplete combustion.

transportation, low-pressure distribution, LNG, and storage.[58] Failure to do this may lead – in many OECD countries and particularly in Europe – to methane emissions being used as a reason to phase gas out of energy balances earlier than would otherwise be the case. It will be in the interests of those who believe they are already compliant with high standards to press for stricter regulation and reporting.

Another environmental objection to gas development is that, given the asset life of power stations, any new gas generation without CCS creates potential carbon 'lock-in' for several decades.[59] However, this argument assumes that just because gas-related assets exist they will be utilised. The reality in many countries is that zero marginal cost renewable power has led (among other factors) to gas-fired stations either running at low load factors or being mothballed. To the extent that costs of renewables combined with electricity storage continue to reduce, the risk for gas assets is that they will be progressively marginalised into providing seasonal back-up, which is why in many (particularly European) countries new power-related gas investments will require regulatory or government support.

Security of supply

Security of supply debates in relation to gas are generally defined in terms of domestically produced versus imported energy, despite the fact that in terms of the physical security of energy supply this proposition does not hold true. In Asian countries (and also elsewhere) any energy source which is domestically produced tends to be defined as 'secure' while imports are by definition 'insecure'. However, the 2011–14 period brought the issue of gas price security into sharp focus as many importing countries, with long-term contracts linked to oil, were exposed to 50–100 per cent increases in their import bills. This reinforced the view that domestically produced energy (especially coal) was secure because the costs were controllable, and created nervousness about long-term gas contracts with uncontrollable price exposure. To some extent, floating storage and regasification units (FSRUs which are LNG import facilities) provide price security as the ships can be sent away if the price of gas becomes unaffordable or uncompetitive with alternatives.

Supply and demand security was represented in the traditional commercial framework by long-term contracts with destination clauses.[60] Buyers wanted to be certain that they would receive specified quantities of gas over a long time period, and sellers wanted to know they would have long-term markets to cover their investments in development and delivery infrastructure. But as markets matured and liberalised, the benefits of long-term stability have become outweighed by the drawbacks of commercial rigidity, both in terms of price and volume. Increasingly, buyers are seeking flexibility (specifically the right to vary delivery volumes in relation to their demand requirements) and price security (namely a guarantee that their purchases will remain competitive with other gas supplies, as well as with fuels which compete with gas in their markets, and will not change simply because of changes in oil prices). In that context, *price* security is becoming more important than *supply* security. This is leading in the direction of shorter contracts, destination flexibility, and short-term trading; these are already established in North American and European markets, but not yet in Asia. And if, as has been suggested, by 2020 there will be 18 cargos of LNG on the water on every day of the year, supply security will be less of a concern, if a cargo can be diverted at short notice by paying a slightly higher price.

The other major aspect of supply security is political, mainly (but not exclusively) focused on Russian gas. In a European context, Russian gas supplies and pipelines are deemed by some governments – particularly in Poland and some Baltic countries – to be a threat to national security (see Section 1).[61] It is possible that the share of Russian gas in European demand could increase substantially from 30–

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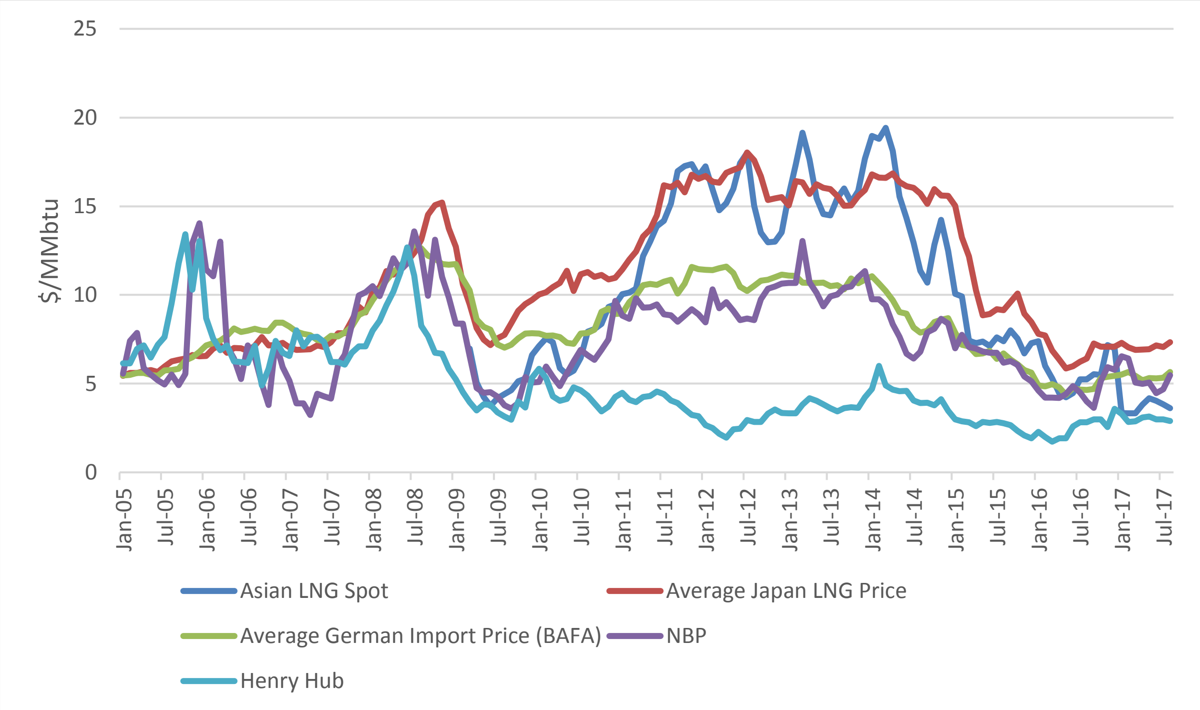
[58] For existing initiatives see Le Fevre (2017), and most recently Methane Guiding Principles (2017).
[59] Ecofys (2017); Corporate Europe Observatory (2017); Oilchange International (2017).
[60] For a discussion of long-term contracts in Europe see Stern and Rogers (2012); in relation to Asia and LNG see Corbeau (2016).
[61] For the Polish view see PGNiG (2017).

35 per cent in the mid-2010s to 40–50 per cent by the late 2020s, as LNG availability for Europe diminishes and alternative pipeline supplies fail to materialise.[62] Should that scenario become reality, it is possible that (at least some) European governments could decide that the degree of exposure to Russian gas requires an enforced reduction of gas in their energy balances. The benefit of such action, and whether it could be construed as being consistent with other EU energy and environmental objectives, is difficult to judge.

International gas prices

Figure 13 shows international benchmark prices of gas during the period 2005–17 from which it is clear that, aside from US Henry Hub prices since 2009 and European prices for brief periods in 2006, 2009, and 2016, international prices have been above (and for most of the time substantially above) $5/MMbtu.[63]

Figure 13: International benchmark prices for gas and LNG 2005–17 ($/MMbtu)



Source: Rogers (2017), Figure 7, p.8 (updated).

Comparing this with Figure 3, it is clear that wholesale price levels for the same period in the Middle East, Latin America, Africa, and the FSU were lower (and for most of the period substantially lower) than $4/MMbtu. Therefore, in relation to international benchmarks, gas has been sold at subsidised prices.[64]

But this conclusion is overly simplistic in several respects:

- The pricing of gas in an individual country can be different to the regional average (as shown in Section 3).
- Even at a country level, wholesale gas prices may fail to represent regional or sectoral customer groups which can afford to pay much higher prices than average levels.

[62] See Stern (2014), for an account of the difficulties of reducing dependence on Russian gas due to lack of availability of alternative pipeline gas.
[63] The exception being NBP for a short period in 2007 and 2009.
[64] Latin American prices rose above $4/MMbtu briefly during 2013–14. Asian prices were below that level until 2010.

- Individual (particularly) pipeline gas exports from countries such as Bolivia and Qatar have their own regional dynamics which are not related to international benchmarks.[65]

Nevertheless, wholesale prices in the majority of countries in Asia, Africa, Middle East, former Soviet Union and Latin America (Figures 6–7 and 9–12) for the period 2005–16 have been at levels which:

- may not cover the cost of gas which started production in the 2010s,
- probably do not cover the cost of new non-associated gas production, and
- certainly would not have covered the cost of imported LNG.

The way in which this has been managed varies in different regions and is very difficult to factor into projections, because the decision to provide or remove subsidies is overwhelmingly political.

[65] For Bolivia–Brazil and Bolivia–Argentina, see Honoré (2016), pp. 98–9; for Qatar–UAE see Dargin (2008).

5. Supply potential – costs of new gas pipeline and LNG projects

Having examined wholesale prices of gas in different regions, the next logical question is whether new gas can be developed and delivered to these markets at costs which are affordable and competitive in these regions. Costs of new gas developments – both for production and exports – are specific to location, distance, terrain, and political sensitivities. They are also shrouded in confidentiality and tend to be project-specific. What follows, therefore, involves generalisations based on research from available public domain data.

Pipeline gas projects

Very few substantial [66] new international pipeline projects are either contemplated or under construction. The most notable of these are Turkish Stream (from Russia to Turkey), Tanap/TAP (from Azerbaijan to Turkey and further to Italy), and Power of Siberia (from Russia to China). Only the last two of these are based on new field developments: Shah Deniz 2 (Tanap/TAP) and Chayandinskoye (Power of Siberia). [67] The other major gas pipeline in an advanced stage of development is Nord Stream 2 (Russia to Germany) which is not based on new field development.[68]

Other substantial international pipelines which have been in the planning stage for many years (and which continue to be mentioned in government statements) include the: TAPI (Turkmenistan–Afghanistan–Pakistan–India), Iran–Pakistan, Iran–Iraq, Iran–Oman, additional Russia–China (Altai and Sakhalin), and Central Asia (mainly Turkmenistan)–China pipelines.[69] A more recent project, proposed in 2017, is the East Mediterranean (Israel–Cyprus–Greece–Italy) pipeline. [70] The main feature of these pipelines is that most of them are designed to allow countries (and companies) which have discovered very large reserves in excess of domestic requirements to sell substantial quantities – between 9 and 40 Bcm/year – of gas to buyers able to enter into 20–25 year contracts, to support the necessary financing of field development (often amounting to tens of billions of dollars). In order to maintain this traditional model of gas development, they need to locate very large – and growing – gas markets with creditworthy buyers who are willing to commit to 20–25 year (in contrast to shorter 5–10 year) contracts. At the time of writing, none of these pipelines seemed likely to be completed prior to the mid-2020s.[71] This means that, aside from Azerbaijan–Europe (Tanap/TAP), the only large-scale international pipeline projects over the next decade will be those from Russia to Europe (including Turkey) and Russia to China. Thus, most international gas trade in the 2020s and (and probably beyond) will be LNG-related.

LNG projects

Research published by the OIES gas programme allows some generalisations to be made about costs of recent and forthcoming LNG supplies. [72] In the late 2000s and early 2010s, the entire hydrocarbon sector experienced substantial project cost inflation, which only began to reverse

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[66] By ‘substantial’ is meant projects which are not short interconnectors between adjacent countries but pipelines of significant length carrying significant volumes i.e. more than 10 Bcm/year.

[67] For details of these projects see: Turkstream Project: http://turkstream.info/project/; TANAP Project (TRANS Anatolian natural gas pipeline project): www.tanap.com/tanap-project/why-tanap/; Trans Adriatic Pipeline: https://www.tap-ag.com/; Power of Siberia: www.gazprom.com/about/production/projects/pipelines/built/ykv/.

[68] Details of the Nord Stream 2 pipeline can be found on the company’s website https://www.nord-stream2.com/

[69] For details of all Iranian pipeline projects see Hassanzadeh (2014), pp. 37–43. For details of the early negotiations on TAPI see Sen (2012), pp. 290–2. For details of Altai see Henderson and Mitrova (2015), pp. 25–7. For details of the Sakhalin–China pipeline see Henderson (2017), pp. 14–15. The fourth Central Asia–China pipeline (Line D) has been subject to a number of postponements, most recently in March 2017, RFE/RL (2017).

[70] ‘EU, Israel agree to develop Eastern Mediterranean gas pipeline’, RT News, 4 April 2017. https://www.rt.com/business/383410-eu-israel-mediterranean-gas-pipeline/.

[71] IEA WEO (2017), p.355 is even more pessimistic about the future of TAPI. Although the pipelines from Iran to Pakistan, Iraq, and Oman could be completed relatively quickly, this seems unlikely for commercial and political reasons. Some sections of TAPI (principally in Turkmenistan) have been reported as completed.

[72] For a detailed discussion of LNG project costs see Songhurst et al. (2016), especially pp.132–60.

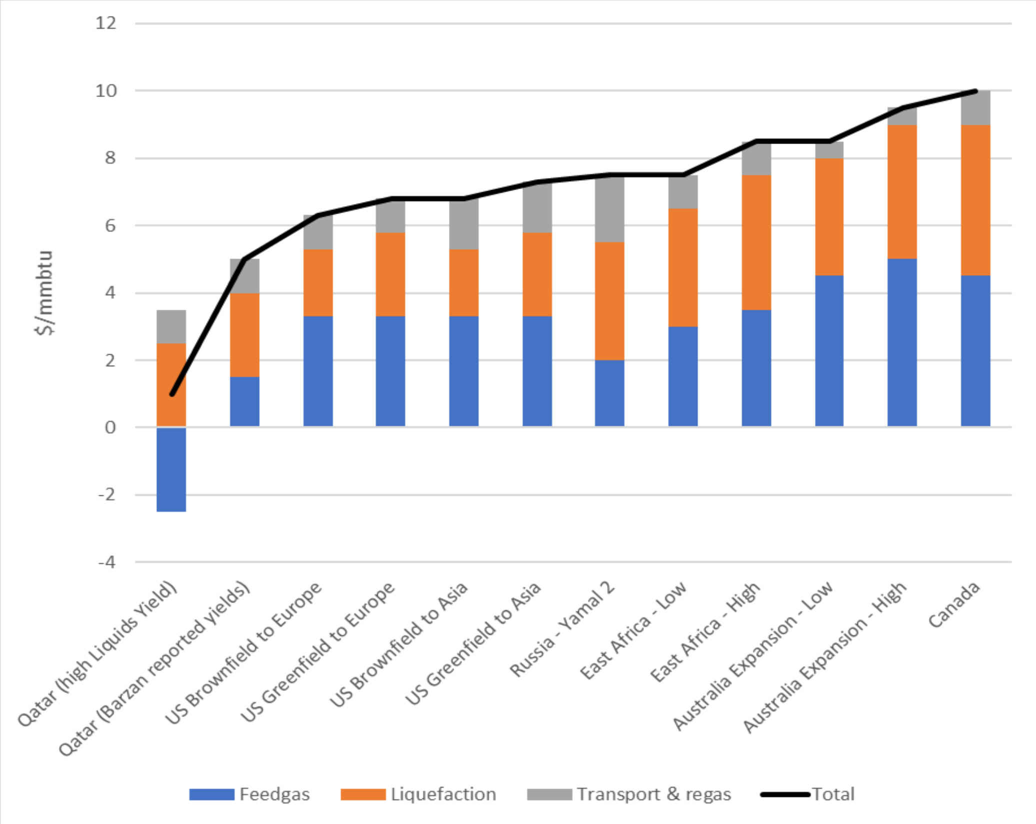
following the collapse in oil and gas prices in 2014. Long-run marginal delivered costs of LNG projects, which took their final investment decisions in the 2010s, commissioning during 2015–20, ranged from $8–11/MMbtu; for Australian projects the range was somewhat higher at $10–14/MMbtu.[73] For US LNG projects, at a Henry Hub price of $3/MMbtu, and a tolling fee charged by the LNG plant of $3.00–3.50/MMbtu, exporters will recover the full cost of their investment at delivered prices of $8.00–8.50/MMbtu in Asia.[74] This means that even given the exceptionally low cost of US shale gas production which (as we have seen above) official projections suggest will remain in a $3–5/MMbtu range for the next two decades, it may be difficult for LNG exports to be competitive in many markets and to be profitable for investors.

Floating liquefaction and regasification units (FLNG and FSRU) have the potential to revolutionise the capabilities of the LNG industry by commercialising what were previously regarded as stranded reserves; they also make it possible to reach new markets which had been considered too small, too remote, or where regional politics were too complicated, to make long-distance pipelines possible. Many of the smaller and newer (or yet to start) gas markets in Table 1 have been, and are likely to be further, developed by FSRUs. But the costs of this technology are also significant and are very dependent on the distance from the shore and the technical specifications of the plant.

A 2016 review of FLNG projects at various stages, from planning to near-completion, revealed costs in the range of $5–7/MMbtu (for the floating vessel only) for the larger projects, to $2–3/MMbtu for smaller projects.[75] FSRU costs are in the range $0.4–0.7/MMbtu depending on the load factor of the facility, but these figures do not take into account leasing (FSRUs are usually leased rather than owned) and operating costs.[76] FSRUs have major advantages over land-based terminals in terms of the speed with which they can be acquired and installed; this can be less than a year, assuming availability of a vessel. But there can be other problems for very small markets, such as islands seeking to replace diesel generation with less expensive LNG. In the case of some Caribbean islands requiring less than one cargo per month, the cost of installing specialised containerisation equipment in Barbados increased delivery costs to $10/MMbtu in 2016/17, compared with spot prices of only just over half this figure for much of that period.[77]

[73] These figures represent the prices that these LNG projects, many of which suffered significant cost-overruns, require to recover their full costs. Rogers (2017), p.16; Henderson, J., 'The Supply Outlook: Australia and the USA', in OEF (2016), p.4.
[74] It is important to stress the relevance of 'full cost'. Projects may be profitable on an operating cost basis, but fail to recover their initial investments. For more details of Henry Hub-priced LNG export contracts see Stern (2016) especially pp. 478–81.
[75] Songhurst (2016), Chapter 4.
[76] Songhurst (2017).
[77] 'Power to the islands in the Caribbean', Stewart, P., *Interfax Gas Daily*, 26 July 2017, p.7.

Figure 14: Estimated breakeven costs of new LNG projects*



* US estimates assume significant liquefaction cost reduction from previous projects and a Henry Hub price of $3.3/MMBtu.

Source: Rogers/OIES.

Estimated break-even costs for LNG projects which had yet to take a final investment decision in November 2017 are shown in Figure 14. With the exception of Qatar, where costs are low and feedgas costs can be negative (because of the liquids associated with the gas), delivered costs for new projects are in the range of $6–10/MMbtu, which includes potential for future cost reduction, with the USA at the bottom of this range and Australia and Canada close to the top. Figure 14 assumes significant reductions in liquefaction costs (and tolling fees), for example from $3.00–3.50 for US LNG projects which are operating or under construction down to $2.50/MMbtu.

6. Increasing complexity of the commercial gas framework

The traditional commercial gas model relied on selling large volumes of gas on 20–30 year take-or-pay contracts (often at oil-related prices) to triple A-rated utilities with a monopoly of sales to creditworthy power, industrial, or citygas customers which mostly only had a choice of purchasing alternative fuels, rather than alternative supplies of gas. The traditional way to start and expand a gas market was to find ‘anchor’ power and industrial customers requiring high load factor gas, and use them as the security on which supply and infrastructure could be financed under long-term 20–25 year contracts.[78]

By the 2010s, the commercial gas framework had become much more complicated, partly due to alternatives to gas in power generation, and partly to privatisation of utilities and liberalisation of gas and power markets. These trends are familiar from previous research on Europe and will only be summarised briefly here.[79]

Using gas-fired power generation for anchor loads in both existing and new gas markets, and persuading buyers to sign traditional long-term contracts, has become much more difficult for a number of reasons:

- Price differentials between (particularly domestically produced) coal and (particularly imported) gas mean that combined-cycle gas-fired power plants cannot compete with coal-fired power plant. In China, a combination of policies related to improving air quality and mandated closure of some older plant have allowed the expansion of gas in the power and heat sectors. In the UK, a high carbon support price has boosted gas-fired generation, closing a large proportion of coal-fired capacity. However, these are isolated examples and, despite repeated arguments from the gas community, there is no clear indication from the Nationally Determined Contributions submitted post-COP21 that substantial numbers of countries intend to use gas on a large scale to solve either air quality or carbon reduction problems.[80]
- Wind (both onshore and offshore) and solar power generation, combined with battery storage, have substantially reduced in cost in the 2010s, and these trends are likely to continue.[81] Although intermittency and the need for grid reinforcement add to the costs of wind and solar power, these sources are increasingly likely to have policy priority over gas-fired generation in the majority of countries for both environmental and security reasons, except in countries where urban air quality needs to be improved as a matter of urgency. Gas can still have a role in backing up renewable energy, particularly on a seasonal basis for countries with a winter heating load, but the resulting load factor will not be sufficient to commercially support new gas-fired power stations (and may not even be sufficient to maintain existing stations) without a capacity charge or similar regulatory support.
- Privatisation and liberalisation policies in many parts of the world have meant that the previous model – where utilities had a national or regional monopoly of customers and could pass through prices to their customer base – has been replaced by a more competitive structure. As a result, gas and power utilities have become less certain of both their demand, and of the price at which they will need to offer, in order to retain their customer base.
- Creditworthiness of buyers in low-income countries cannot be taken for granted even (and in some cases especially) if they are government owned. As a result, financing of projects becomes

[78] Although in much of Europe the route was large-scale switchover of industry and households from oil products, and later coal, to gas.
[79] Stern (2017).
[80] ‘INDCs as communicated by Parties’, http://www4.unfccc.int/submissions/indc/Submission%20Pages/submissions.aspx. The IEA mentions ‘less than 30 out of 160 submissions’. IEA (2016), p.169.
[81] For a review of these trends see IEA (2017c), pp.141–56.

more complicated and illustrates a further methodological problem related to assuming that the prices which are recorded as charged are actually paid by all customers.

This means that in new markets such as Africa and small island states, where gas sales to power generation are planned to serve as the anchor load, creditworthiness and the introduction of renewables threaten commercial viability. In existing markets, particularly those which have introduced liberalisation and competition, gas-fired power stations can only be expected to run at middle – which may increasingly become peak – load, and therefore cannot serve as an anchor for expanding gas demand. In these markets, the industrial, residential, and transport sectors will increasingly become the main targets of future demand. These sectors are not only more complex in terms of sales and the provision of network infrastructure, but also potentially in relation to creditworthiness, subsidy risk, and decarbonisation.[82] IOCs traditionally minimised sales to domestic markets in countries where they were developing gas export projects because of low prices and subsidies, but many governments have imposed domestic market obligations (particularly for LNG exporters).[83] National gas producers have struggled for profitability in domestic markets, and cross-subsidised domestic sales with exports.[84]

[82] Decarbonisation of heat in the industrial and residential sectors (of even advanced countries) will be much more complex than for the power generation sector.

[83] Domestic market obligations (DMOs) typically require a gas exporter to sell a certain percentage of the gas which is being developed to the domestic market.

[84] Russia's Gazprom is a good example, see Henderson et al. (2014), especially pp. 117–36.

7. Challenges to the future of gas

A respectable claim to be a transition fuel

Most long-term energy outlooks are based on meeting the COP21 objective of the 2 degrees C target.[85] International policy discourse therefore relates to the reduction, and then to the phasing out, of fossil fuels; modelling exercises are based on different rates of achieving this goal. These studies – whether by energy companies, international organisations, NGOs, or academics – show gas demand either stable or growing in almost all regions in most scenarios for the period up to 2030.[86] For the post-2030 period, the outlook for some regions is for flat or declining gas demand, but many scenarios show growth and others only modest decline, up to 2040. Only post-2040 does gas become progressively globally 'unburnable' if COP21 objectives are to be met. Regionally, and especially nationally (and in large countries sub-nationally), the picture will be very different, and this level of granularity is crucial for any kind of detailed appraisal of the future of gas. But despite these reservations, in the opinion of this author, a 20-year horizon prior to *significant global decline* qualifies gas to be regarded as a 'transition fuel'.

Shorter-term and longer-term challenges of affordability and competitiveness

This paper does not challenge the assumption that carbon reduction will be a major, if not *the* major, constraint on the future of gas post-2030 (and certainly post-2040), but has advanced the proposition that in many regions other factors – and especially affordability in relation to the cost of new supply and competition with other sources of energy – will be a more immediate determinant of gas demand.

The period 2011–14 did a great deal of damage to the future of gas in four respects:

- Very high international prices caused reductions in the rate of increase (and in some regions an absolute reduction) of gas demand;
- For a large number of low-income countries importing (or considering importing) LNG, prices during this period were unaffordable in absolute terms, or uncompetitive in relation to other energy sources;
- Cost inflation for large export projects suggested that these price levels would need to continue in order to support new gas developments;
- Many investors in, and operators of, projects being commissioned in the mid to late 2010s are finding it difficult to recoup the cost of their investments, and will be more cautious in relation to future projects.

For the majority of 2016–17, international price benchmarks were in the range of $5–8/MMbtu, which created additional demand for gas in many regions.[87] Although upstream costs are reported to have fallen significantly since 2014, there was less evidence of a fall in costs which would create confidence about the commercial viability of future greenfield LNG projects, which will comprise the majority of future international trade.

In relation to affordability it is not useful to try to generalise; in all regions – and indeed all countries – the picture is different. North American shale development costs are expected to allow Henry Hub prices to remain in the range of $3–5/MMbtu for the next two decades. At these levels, gas is not challenged in North American markets, but even with significant cost reduction, new US LNG export projects would need to receive prices of $6.00–9.30/MMbtu to recoup the full cost of their investment

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[85] The objective of limiting the average global temperature increase in 2100 to 2 degrees (or 'well below 2 degrees') Celsius above pre-industrial levels.

[86] These are modelling studies, in contrast to studies which are designed to show that natural gas and other fossil fuels must be phased out by a certain date either globally or in a specific region.

[87] At November 2017 exchange rates, $5–8/MMbtu was roughly equivalent to €14.5–23.2/MWh. By the end of 2017 spot (JKM) prices in Asia were close to $10/MMbtu (€29/MWh).

(Figure 14).[88] Elsewhere in the OECD, and especially in Europe, markets face challenges from a combination of carbon reduction policies leading to increased competition from solar and wind energy supported by battery storage, where ongoing cost reductions will inevitably lead to gas demand destruction in power generation.

In low-income regions, wholesale prices of less than $4/MMbtu over the period 2005–16, give an indication of affordability levels. It would therefore be wise to imagine that, even with significant increases in GDP, a future ceiling price for gas in Latin America, Africa, and large parts of Asia would be in the range of $5–6/MMbtu. A central conclusion of this analysis is that there are limited numbers of countries outside the OECD which can be expected to afford to pay wholesale (including import) prices of $6–8/MMbtu and above, which may be needed to remunerate the 2017 delivery costs of large volumes of gas from new LNG projects. In OECD countries (outside North America) prices towards, and certainly above, the top of this range are likely to lead to progressive demand destruction.

Major exceptions to this affordability proposition would be countries which are still using diesel for power generation (such as small island states) and oil exporting countries where greater gas use allows more oil to be freed up for export, and where governments (primarily in Gulf countries) are able to provide large-scale subsidies to industries and citizens. Other exceptions would be niche markets which need a constant supply of energy, or where gas is needed to substitute – on a daily, seasonal or (in the case of hydropower) a longer basis – for intermittent renewables.

Table 4: Natural gas price scenarios 2025–24* (real 2016 $/MMbtu)

	New Policies				Sustainable Development	
	2025	2030	2035	2040	2025	2040
USA	3.7	4.4	5.0	5.6	3.4	3.9
European Union	7.9	8.6	9.1	9.6	7.0	7.9
China	9.4	9.7	10.0	10.2	8.2	8.5
Japan	10.3	10.5	10.6	10.6	8.6	9.0

*US figures reflect the wholesale price prevailing on the domestic market; EU and China figures reflect a balance of pipeline and LNG import prices; Japan figures are LNG import prices

Source: IEA WEO (2017), Table 1.4, p.52.

The demand levels shown in Figures 1 and 2 are associated with the gas price import scenarios shown in Table 4. Prices are significantly lower over the whole period for the Sustainable Development scenario because they:

> '..are designed to ensure that sufficient new projects are brought online to balance supply and demand while ensuring all generate an adequate return.'[89]

which suggests an emphasis on commercial viability rather than affordability.

Our analysis suggests that Sustainable Development European prices are within the range necessary to prevent demand destruction, but internationally traded prices for LNG of $8–9/MMbtu (Japan and China in Table 4) will be too high for the majority of low-income importers. These price levels, therefore, cast doubt on the viability of gas outside the OECD region, with the exception of high affordability countries such as China, while also raising the question of how many new projects can be profitably developed at these price levels. The significantly higher New Policies prices are more reassuring for project developers (as they remunerate all projects in Figure 14), but they are likely to

[88] This is based on the commercial model of existing and under construction US LNG projects which take Henry Hub prices and add costs along the LNG value chain. For the next generation of US LNG projects, the business model may change to equity participation throughout the value chain aimed at significantly lower delivered costs.
[89] IEA WEO (2017), p.463.

lead to demand destruction in high-income countries as well as putting gas well out of reach of the majority in low-income countries.

Any attempt to quantify the elasticity of gas demand at different current and future price levels is extremely challenging. The IEA shows that for three OECD countries (the USA, Germany, and the UK) prices above $8/MMbtu have historically caused demand to fall, while prices below $6/MMbtu have created an increase in demand.[90] However, this elasticity may not apply to lower-income countries and it is a Herculean task to try to untangle the different strands of policy and competitive fuel prices impacting future gas demand. At a minimum, this would require examining the evolution of gas prices, coal prices, renewable/storage and nuclear power costs, and carbon charges over the next two decades in a very large number of countries.

Table 5: Gas imports by region/country in 2040, New Policies scenario (Bcm)

	Net Imports in 2040	Increase compared with 2016	Most important considerations
China	278	205	Import levels depend on success of domestic unconventional production
India	99	75	Dependent on gas price reform and environmental policy changes
Other Asia Pacific	178	230*	Nuclear power development in Japan, Korea, and Taiwan; coal development in many SE Asian countries and affordability in South Asia
European Union	329	60	Imports needed to replace falling domestic production

*in 2016 the region was exporting 52 Bcm

Source: IEA WEO (2017), Table 8.4, p.361.

Table 5 provides a projection of gas imports for 2040 for the New Policies Scenarios[91] for several, but not all, regions. It does not include either the Middle East or Latin America where projections are complicated by the fact that some countries (notably Qatar) intend to increase exports but many others will begin or expand imports. LNG will account for the vast majority of incremental imports in 2040.[92] Indeed China is the only country where there will be any significant increase in pipeline imports with the increase in imports equally split between LNG and pipeline gas. In addition, Chinese gas demand is 10 per cent higher in the Sustainable Development scenario, dependent on very substantial unconventional gas production (around 200 Bcm in the 2030s) with cost estimates of $7–11/MMbtu – equivalent to New Policies price levels.[93]

The problem with the projections in Table 5 is that New Policies prices of $9.4–10.6/MMbtu probably rule out the majority of Indian LNG imports and a significant share of those into other Asian countries. In Europe, these price levels destroy demand for LNG, with the result that more pipeline gas is imported or, if that is not available at more competitive (Sustainable Development) prices, gas demand falls faster than would otherwise have been the case.

[90] IEA WEO (2017), Figure 8.5, p.342.
[91] There are no data for the Sustainable Development scenario, but as far as LNG is concerned, the figures are not significantly different. IEA WEO (2017), p.633.
[92] IEA WEO (2017), Figure 8.11, p.362.
[93] IEA WEO (2017), Figures 14.16 and 14.17, p.591 and 593. At Sustainable Development price levels (Table 4) around half of this production would not be economic.

Future gas demand: from power generation to industrial and residential sectors

In the power generation sectors of both established and new markets, gas will increasingly need to compete with solar, wind, and battery storage technologies which are already competitive in many markets, continuing to fall in cost, and attractive because they provide greater employment and lower foreign exchange costs than imported gas. (Domestically-produced coal has similar attributes but much higher carbon emissions.) This is likely to mean that gas will be progressively squeezed out of the power generation sector, or reduced to providing a back-up role for intermittent renewables, which will not be sufficient to remunerate investment in new gas-fired generation without regulatory support (such as a capacity charge). The main exceptions are China and India, where air quality problems may lead to large-scale replacement of coal by gas-fired generation.[94] Other exceptions (but probably on a smaller scale) will be replacement of diesel/fuel oil-fired generation with gas in the Middle East, Africa, and small island states, or for customers who require 24/7 electricity supply in countries where this is not generally available.

But in many countries, the future of gas will need to focus on the industrial, residential, and transport sectors, particularly in countries where gas can replace oil products. In comparison to power generation, this will require a more complicated business model, with sales of smaller volumes to a larger and more geographically dispersed customer base requiring an expansion of network infrastructure and therefore higher costs.

National typologies: which are the most promising future gas markets?

Table 6 suggests a typology of regions and countries, in relation to their energy, environment, and gas attributes, and the policies discussed in this paper. The criteria for these typologies are: replacement of declining domestic production and expiring long-term import contracts, affordability, fuel switching, subsidy, and peak requirements related to renewable intermittency. Countries may encompass more than one of these typologies which may also be conflicting – the most obvious example being countries which should switch from coal to gas for environmental (air quality and carbon reduction) reasons, but do not because of a combination of employment, import dependence (generally but often inaccurately referred to as `security of supply'), low affordability and lack of policy enforcement.

From these typologies, the most promising future market above all others is China, which will increase both gas demand and imports on a scale of hundreds of billions of cubic metres. A combination of energy demand requirements, air quality policy, and high affordability means that even if its target of 10-15 per cent of primary energy is not achieved, the country will increase its gas demand both up to and potentially beyond 2040. Similar criteria should apply to India, but low affordability, lack of price reform, and less urgency about air quality improvement, mean that significant increases in gas demand are much less certain.

[94] In these countries new coal-fired power stations or long-distance electricity transmission based on coal-fired power, may resolve some urban air quality (although not carbon emission) problems.

Table 6: National gas typologies*

TYPOLOGIES	REGIONS/COUNTRIES	
Replacement of domestic supply and expiring long-term import contracts	Europe, Japan, Korea, Indonesia, Gulf countries	
Low-cost (price)/high penetration countries	USA, Canada, Russia, Qatar, Central Asia	
High affordability/low penetration countries	(eastern provinces of) China, Thailand, the Philippines, Brazil	
Low affordability/low penetration countries	India, Vietnam, Ivory Coast, Ghana, South Africa	
Low affordability/high penetration countries	Argentina, Pakistan, Bangladesh	
High affordability/low price subsidisers	(most) Middle East oil exporters	
Coal to gas switchers – related to urban air quality (and carbon reduction)	China, USA, Canada, India, [Germany?]	
Oil to gas switchers	all Gulf oil producers and exporters, small island states	
(Potential) nuclear to gas switchers	Japan, Korea, Taiwan [France?]	
High affordability/peak use when renewables unavailable:	• wind and solar • hydropower	Europe, many US states much of Latin America

*See Table 1 for price definitions and data on penetration levels

Source: Author

The Gulf states will also see significant expansion, despite the fact that gas markets are already large and heavily subsidised, and many are developing solar, wind, and nuclear power. Elsewhere, South East Asian countries – Thailand, the Philippines and Vietnam – with different levels of penetration and affordability, may be important future markets. There is much potential for expansion of gas demand in Africa but affordability seems likely to mean that many countries will rely on domestic gas, aside from niches (mainly large cities) which can afford to import LNG (using FSRUs). In Europe, despite the fact that demand will probably not increase and may fall in the 2020s, there will be large additional import requirements during that period, due to falling domestic production. In North America, low-cost shale gas is likely to delay a peak in demand until after 2030, followed by decline which will accelerate if the costs of domestic production prove to be higher than currently projected.

Cost limitations and contractual time horizons in the value chain

A question increasingly asked in a carbon-centric world is whether companies should continue to invest in fossil fuels, including gas, since carbon reduction targets could strand these investments before they can yield profitability. This is a particularly relevant question for upstream, exploration and development, and infrastructure (pipeline networks and LNG facilities) developments with long amortisation periods. But of more immediate concern for companies throughout the gas value chain is the concern that the cost of new upstream and export developments may not yield the required level of profitability, particularly given the conclusion of this paper: that the commercial viability of gas or LNG which cannot be delivered to markets at a cost of $6–8/MMbtu should be considered questionable.

A general proposition, therefore, is that the major immediate challenges for upstream companies will be a combination of locating low-cost gas as close as possible to potential markets, combined with cost reduction throughout the LNG value chain. For gas reserves in general, renewable energy options and future carbon constraints will become increasingly important in relation to the required level and duration of production for profitable development.[95] In contrast to those commentators warning that carbon emissions from new gas developments will be 'locked in' for many decades, the

[95] See for example Taliotis et al. (2017) who argue that if gas does not become available in Cyprus in the period 2023–30 then it is prudent to invest in renewable technologies which would probably mean the country's own reserves will not be developed.

reality may be that delays in developing reserves, make it more likely that they will either never be developed or 'locked out' before investors receive their anticipated remuneration.

Further downstream in liberalised markets, utilities (particularly in Europe) have incurred substantial trading losses, lost a large part of their asset value, and struggled to survive as their traditional business model has been eroded by a mixture of increased competition and the introduction of renewables with strong policy support. These events, and the growing importance of gas and LNG trading, have emphasised short-term profitability and resulted in a decreasing ability to think 'long term', not just the 15–30 years which was the traditional gas industry long-term contract mentality but, for many companies which used to have this mentality, a horizon beyond the next two shareholders' meetings.

In this short-term mindset, focusing on even a 2030 (let alone a post-2030) timeframe is highly problematic. Long-term contracts – traditionally 20–25 years – have become 5–10 years, and for traders, anything beyond 12–18 months. Investments in major new infrastructure become problematic without 15–25 year ship-or-pay or tolling contracts (to which very few players will commit), or policy and regulatory support. Carbon-centric regulators and policy makers, mindful of NDC targets under COP21, may be increasingly unwilling to provide such support in the absence of compelling evidence of problematic consequences, for example in relation to security of supply. This suggests the need to 'reintegrate' the value chain, possibly through equity joint ventures rather than long-term contracts. Carbon reduction constraints suggest that, in many regions, it will be difficult to amortise major investments over a 20 year period unless these are made prior to the early to mid-2020s. This applies particularly to network investments, but also to upstream developments requiring long-term contracts to underpin financing which may exceed $10 billion (and in some cases multiples of that figure).

Unburnable, or unaffordable and uncompetitive?

In the low-price world of 2017, the major debate in the gas community is when the anticipated 'glut' of LNG will dissipate, and the global gas supply/demand balance will tighten. The unspoken assumption being that when this happens – generally believed to be around the early/mid 2020s – prices will rise somewhere close to 2011–14 levels, allowing a return to profitability for projects which have come on stream since the mid-2010s and providing the conditions for new projects to move forward. This paper suggests that such an assumption is flawed but, should it prove to be correct, carries within it major problems for the future of gas.

A return to internationally traded gas prices above $8/MMbtu would make gas unaffordable in many potential new gas markets, and uncompetitive with domestic (and imported) coal in both low-income countries and high-income countries which lack either environmental regulation or carbon-related taxation. At these price levels gas will also become progressively less competitive with wind and solar (backed by battery storage) which will further contribute to demand destruction.

The key to gas fulfilling a potential role as a 'transition fuel' over the next two decades is that it must be delivered to high-income countries below $8/MMbtu, and to low-income countries below $6/MMbtu (and ideally closer to $5/MMbtu). The major challenge to the future of gas will be to ensure that it does not become (and in many low-income countries remain) unaffordable and/or uncompetitive, long before its emissions make it unburnable.

APPENDICES

Appendix 1. Responses to questions asked at the 2017 FLAME Conference

European Gas Advocacy groups have consistently argued that gas should be regarded as a transition or destination fuel for a low-carbon economy. Do you believe that:

1) These arguments are convincing and will eventually prevail (32 per cent).

2) These arguments have not been convincing and will become decreasingly relevant (26 per cent).

3) These arguments could be convincing if carbon capture and storage was adopted on a significant scale (32 per cent).

4) These arguments do not matter because transition to a low-carbon economy will gradually fade from the political/energy agenda (10 per cent).

Will carbon reduction (COP21) commitments by governments have a decisive influence on European gas demand by 2025–30?

1) Yes, COP21 commitments will make European gas demand higher than it would have otherwise been (23 per cent) (2016 – 41 per cent).

2) No, COP21 commitments will make no difference to European gas demand (9 per cent) (2016 – 17 per cent).

3) Technological progress of renewables and battery storage will have a greater influence on gas demand (52 per cent).

4) Governments are likely to abandon their carbon commitments as 2030 approaches because the cost of achieving them will become too great (16 per cent).

Appendix 2. Types of price formation mechanism

OIL PRICE ESCALATION (OPE)
The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil, and/or fuel oil. In some cases coal prices can be used as can electricity prices.

GAS-ON-GAS COMPETITION (GOG)
The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually, or other periods). Trading takes place at physical hubs (such as Henry Hub) or notional hubs (for example NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short-term fixed-price basis and there will be longer-term contracts, but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category is spot LNG, any pricing which is linked to hub or spot prices, and also bilateral agreements in markets where there are multiple buyers and sellers.

BILATERAL MONOPOLY (BIM)
The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers trading bilaterally.

NETBACK FROM FINAL PRODUCT (NET)
The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.

REGULATION: COST OF SERVICE (RCS)
The price is determined, or approved, formally by a regulatory authority, or possibly a Ministry, but the level is set to cover the 'cost of service', including the recovery of investment and a reasonable rate of return.

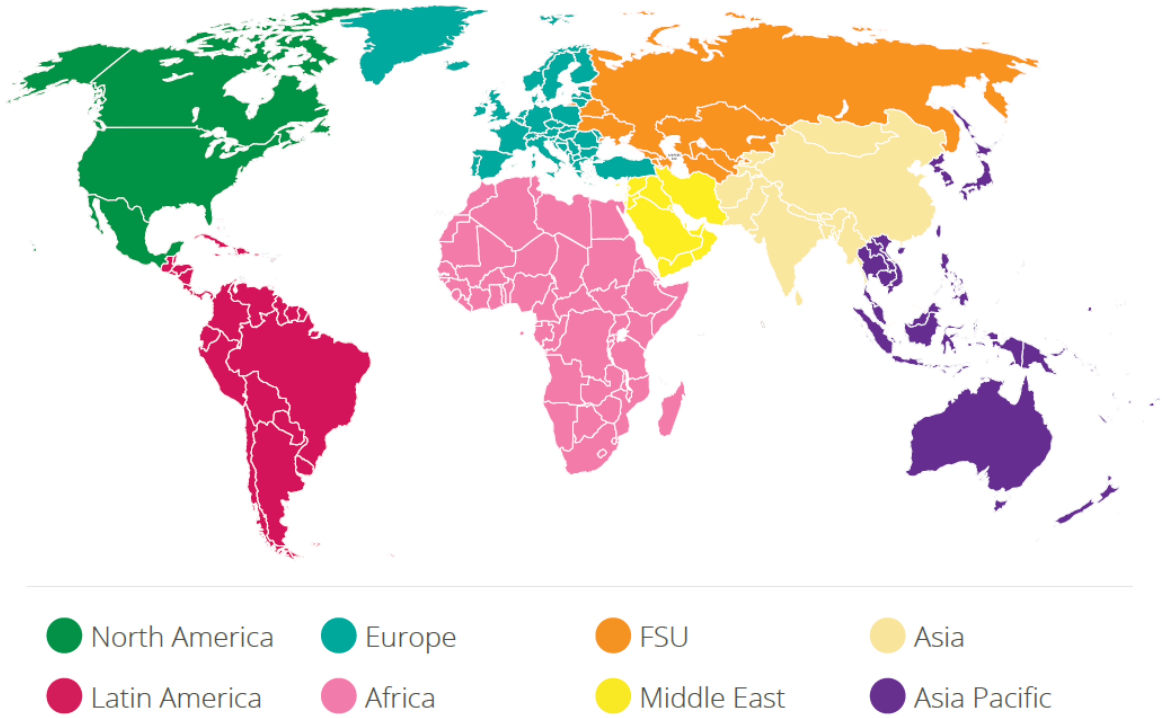
REGULATION: SOCIAL AND POLITICAL (RSP)
The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.

REGULATION: BELOW COST (RBC)
The price is knowingly set below the average cost of producing and transporting the gas, often as a form of state subsidy to the population.

NO PRICE (NP)
The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertiliser plants, or in refinery processes and enhanced oil recovery. The gas produced may be associated with oil and/or liquids and treated as a by-product.

Source: IGU (2017), p.13.

Appendix 3. Map showing the IGU's regional groups



Source: IGU (2017), Figure A1, p.57.

Appendix 4. Methane emissions from gas industry operations[96]

Methane emissions from natural gas operations, arising from:

- venting (deliberate and controlled emissions),
- fugitive emissions (unintended emissions and leakages), and
- incomplete combustion (including during flaring),[97]

is not a new subject but its global warming potential (GWP), particularly in relation to carbon dioxide, has led to increased attention from climate change researchers.[98] Two subjects have attracted particular attention: the absolute volume of methane emissions from natural gas operations nationally and globally, and the relative contribution of natural gas when compared to other energy sources, particularly coal. The subject is complicated by: lack of agreement on whether GWP is the correct measure to use, how the GWP of methane should be measured, and over what time period (20 years or 100 years).[99] Lack of data on methane emissions from gas (and other fossil fuel) operations lead to very wide ranges of estimates, whether using 'bottom up' or 'top down' methodology.

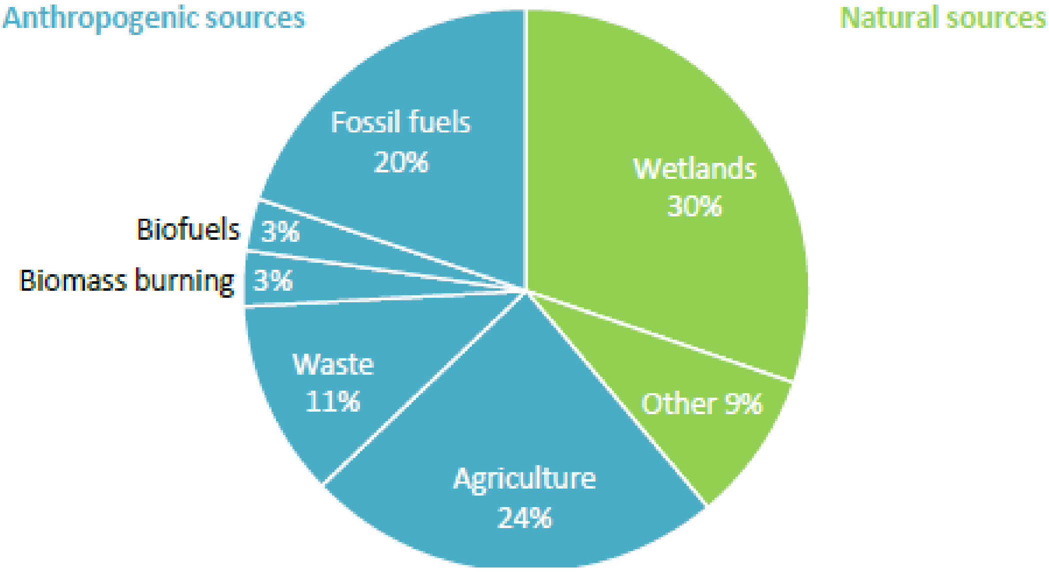
Further important issues complicating estimates are: differentiation of emissions between: anthropogenic and natural sources; gas and oil operations (where these are jointly carried out); upstream (production) and mid/downstream (transmission and distribution) operations; and 'regular' gas industry operations compared to a small number of 'super-emitters'. The latter are particular sources or incidents – accidents, equipment malfunction, human error – which can be disproportionally important in total emissions.[100] This very brief appendix is intended to point readers to useful sources of information and illustrate the conclusion in the text that the industry needs to organise the collection of statistics on methane emissions for the entire value chain on a national basis.

Total global emissions of methane for 2012 were estimated at 570 mt of which: 40 per cent were from natural sources (wetlands, fresh water, geological seepage, melting permafrost, oceanic sources).[101]

The IEA estimates that the majority of global methane emissions are from natural sources and agriculture, while emissions from fossil fuels are estimated to account for 20 per cent of the total in 2012 (Figure A.4.1). The Global Carbon Project estimated fossil fuel emissions of methane at an average of 105 mt/year (with a range of 77–133 mt) averaged over 2003–12, representing 19 per cent of total methane emissions but around a third of anthropogenic emissions.[102] UNFCC data for natural gas sector emissions from selected Annex 1 countries, separated into value chain sectors, are shown in Table A4.1.

[96] This note is drawn substantially from: IEA WEO (2017), Chapter 10; Balcombe et al. (2017); Le Fevre (2017); Balcombe et al. (2015).
[97] Methane Guiding Principles (2017).
[98] For as assessment made nearly 30 years ago see US Environmental Protection Agency (1990).
[99] The IEA does not use GWP methodology, preferring to use model estimates of how absolute volumes of methane impact global surface temperature rise to 2100. IEA WEO (2017, pp. 405–6).
[100] Balcombe et al. (2017) suggest that the top 10% of super-emitters account for 70% of total emissions.
[101] IEA WEO (2017), pp. 416–7.
[102] Global Carbon Budget cited in Le Fevre (2017), Figure 2, p.7.

Figure A4.1: Methane emissions from natural and anthropogenic sources (2012)



Source: IEA WEO (2017), Figure 10.2, p.404.

Table A4.1: Methane emissions from the natural gas sector in selected Annex 1 countries in 2015 (thousand tonnes of methane)

	E&P	Transmission	Distribution	Other	Total	Rate **
Australia*	42	12	172	0	226	0.2%
Canada	104	46	36	295	483	0.2%
France	0	24	20	-	44	0.1%
Germany	1	76	89	27	193	0.2%
Italy	9	31	142	-	182	0.2%
Netherlands	0	7	6	-	13	Neg
Poland	16	6	13	-	35	0.1%
Romania	138	7	20	20	185	1.2%
Russia	1164	3715	497	-	5376	0.6%
Spain	0	2	24	-	26	0.1%
Turkey	2	24	54	-	80	0.1%
Ukraine	75	54	433	575	1137	1.4%
UK	3	2	149	-	154	0.1%
USA	4709	1349	439	-	6497	0.5%

*2012 data

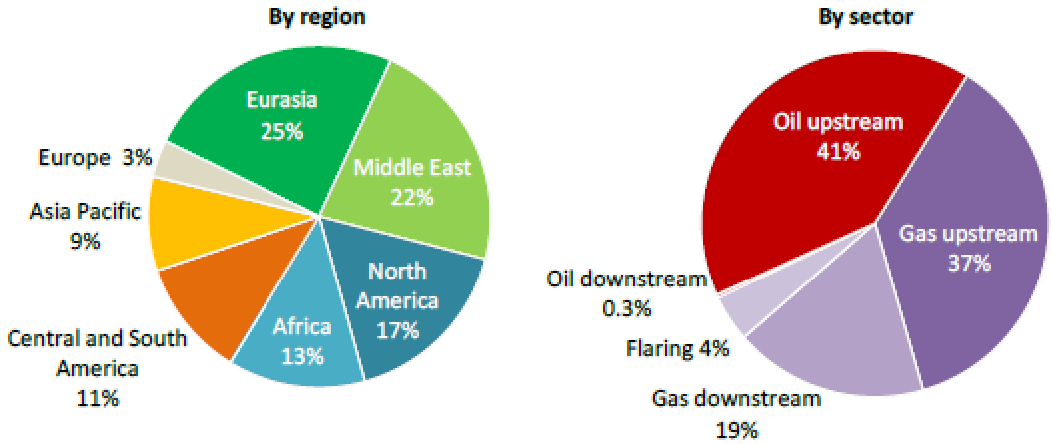
**based on level of reported emissions as a percentage of either the country's 2012 production or consumption, whichever is the greater.

Source: Le Fevre (2017) based on UNFCC and BP World Energy Statistics, Table 4, p.15.

Reporting of emissions is highly variable between countries, supply chain routes, processes, and equipment, and is not reported on a consistent basis across countries. While some companies report methane emissions data from their individual country operations for the part of the gas value chain in which they operate, there is little systematic reporting. Much of the detailed national data on methane emissions originates from North America, and has become important due to emissions from unconventional gas operations.

Figure A4.2 shows a regional and sectoral breakdown of methane emissions from the oil and gas industry; this suggests that 80 per cent are from upstream oil and gas operations, where it may be very difficult to separate emissions where the two fuels are being produced jointly. Data for many regions are problematic due to gaps in reporting.

Figure A4.2: Regional and sectoral breakdown of methane emissions from oil and gas industries (2015)



Source: IEA WEO (2017), Figure 10.7, p.414.

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