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Challenges to the Future of LNG:
decarbonisation, affordability and profitability

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All views expressed and errors which may remain are solely my responsibility.

Preface

In this working paper Jonathan Stern continues our series addressing the potential impact of decarbonisation on the global gas sector. On this occasion the focus is the LNG industry and he poses three key questions as a challenge to project developers. Firstly, he asks whether they are prepared to document the full impact of emissions along the LNG value chain and to develop a decarbonisation narrative beyond the traditional "gas is better than coal" argument. He asserts that such a narrative is already needed in Europe, where gas is increasingly viewed as a problem (rather than a solution) post-2030, and is likely to be needed in the rest of the world within the lifetime of any new LNG project. Secondly, he asks whether LNG can be delivered at a cost low enough to make it attractive in regions of the world where gas demand growth is highest, but where affordability is a problem. And thirdly he asks whether LNG developers can adopt a decarbonisation strategy while also maintaining the profitability of their assets over the longer term. These appear to be existential questions for the LNG industry that have not yet been fully addressed by the key actors in the sector. We hope that by raising these questions now, when they may perhaps seem premature to some observers, that we can highlight a major issue that is facing the gas industry over the coming decades.

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Executive Summary

Despite the fact that 2019 and 2020 are likely to see final investment decisions (FID) on more than 100 bcm of projects, the LNG industry is facing significant challenges related to decarbonisation, affordability, and profitability. Combustion along the value chain (principally that needed to achieve liquefaction at minus 162 C) equates to 11-13 per cent of the gas produced at the wellhead, which means that an LNG project has significantly higher emissions than a typical pipeline gas counterpart. In order to meet COP21 targets, unabated gas demand in Europe will need to decline post-2030 (at the latest). In other regions less stringent targets mean that decline may be delayed until the following decade. A project taking FID in 2019-20, and starting operations around 2024-25, may not have recovered its costs prior to anticipated European demand decline, but should have done so prior to more general global decline; nevertheless, decarbonisation is very likely to impact the return on investment over its anticipated operating life.

For this reason, decarbonisation, although yet to be addressed by most LNG projects, should be very much on the radar of new project developers. The LNG community needs to replace an `advocacy' message - based on the generality of emissions from combustion of natural gas being lower than from other fossil fuels - with certified data on carbon and methane emissions from specific elements of the value chain for individual projects. As carbon reduction targets tighten over the coming decade, LNG cargos which do not have value chain emissions certified by accredited authorities, or which fail to meet defined emission levels, run the risk of progressively being deemed to have a lower commercial value (because they will require buyers to purchase emission offsets of various types) and eventually being excluded from jurisdictions with the strictest standards. There will be no place in this process for confidentiality; nothing less than complete transparency of data and methodologies will be acceptable. This will be the only way to achieve credibility and counter allegations that high methane emissions mean that (natural gas and) LNG projects, are 'worse than (or no better than) coal' in relation to GHG emissions.

In relation to affordability, prospects for new projects look much better than they did three years ago. Cost estimates for most new projects suggest that they will be able to deliver profitably to most established and anticipated import markets at or below the wholesale prices prevailing in those markets over the past decade, particularly in China and south east Asia which are projected to have the largest increases in LNG imports over this period. There may be problems for some new projects to profitably supply India, Pakistan, and Bangladesh without a sustained increase in wholesale prices or prolonged government subsidies in these countries. Spot prices well below $6/mmbtu in 2019 – should they extend into 2020 and beyond – could provide a useful indicator of price elasticity of demand in these markets, but also severely impact the profitability of some existing higher cost projects.

In relation to profitability, LNG projects need to factor in costs related to future decarbonisation requirements in both exporting and importing countries, and when these requirements might be imposed. To the extent that LNG suppliers can meet standards through relatively low-cost offsets – forest projects, low-cost biogas and biomethane – this may not greatly impact their commercial viability. However, any requirement to transform methane into hydrogen with CCS in either the exporting or importing country, would substantially impact project economics and the affordability of LNG relative to other energy choices.

1. Introduction and Propositions

The end of this decade and the start of the 2020s is a very exciting period for global LNG development with huge increases in supply and trading, numbers of exporters and importers, and final investment decisions (FIDs) for a host of new projects; plus the emergence of new business models, and changes in price formation.[1] Projects taking FID during this period will have construction lead times of 4-5 years and an operating life of at least 25 years, specifically until or beyond 2050. But there has been very little discussion of whether and how carbon reduction targets for the next 25 years might impact new LNG projects over their operating life. There must be a strong possibility that within the lifetime of projects which are currently taking FID, greenhouse gas reduction targets may restrict where, how much, and for how long LNG can be sold as unabated methane, and potentially increase the costs and lower the expected returns from new projects. An additional challenge to the future of LNG is whether the cost of new projects may threaten to exceed the affordability of LNG in many of the new markets which are being targeted by developers.[2]

Previous papers in the Future of Gas series focussed on the different parts of the gas value chain in a specifically European but also more general geographic and policy context.[3] This paper returns to the previous 'unburnable or unaffordable' theme (Stern 2017b) but is more narrowly focussed on LNG export projects and the LNG value chain because of the large number of new projects which are taking, and intend over the next several years to take, FID.

Decarbonisation challenges are facing all fossil fuel energy sources including natural gas. Previous papers argued that policy makers in European countries have not been persuaded by the 'advocacy narrative', namely that using natural gas as a transition or bridge fuel – switching from coal to gas, and using gas to back up intermittent renewables - is the quickest, easiest and lowest cost decarbonisation path.[4] While logical, this is the answer to the question that the gas community thinks politicians and environmentalists *should be asking*. But European politicians are under pressure from climate activists insisting on a move from COP21 to 'net zero' targets and a rapid and radical exit from all fossil fuels with no differentiation between oil, gas, and coal. In that policy context the questions which those groups *are asking* are: what is the carbon and methane footprint of gas and how can this be reduced substantially (preferably to zero)? While many in the gas community continue to describe their product as 'low carbon', this has become increasingly disputed both in general discourse and analytically due to methane emissions from the gas value chain.[5]

Outside Europe (and some US states) the advocacy narrative remains relevant but more immediate in relation to air quality improvement than carbon reduction. But the issue of affordability remains paramount particularly in countries where domestic wholesale gas prices have never exceeded $6/mmbtu. This is where the challenges of decarbonisation and affordability combine because:

- where carbon-centric policies prevail, a shift to low and zero carbon gas will raise costs substantially;

[1] For further reading on these issues see: OEF (2019), Fulwood (2019), Steuer (2019), Ledesma and Fulwood (2019), Corbeau and Ledesma (2017).
[2] These are not the only challenges facing the LNG industry. A potentially more immediate difficulty concerns long-term offtake contracts which a new LNG project has traditionally required to secure financing. Recent projects have been launched on the basis of offtakes by portfolio players, a fundamentally different business model which may not be available to smaller players.
[3] Stern (2017a), Stern (2017b), Stern (2019a).
[4] The advocacy narrative is based on carbon emissions from gas combustion being around 40 per cent less than coal and 20 per cent less than oil, IEA (2019a), p.35. This source has a comprehensive review of the fuel-switching potential and merits of gas in relation to emissions.
[5] The UK Advertising Standards Authority has objected to advertising which implies that gas is a 'low carbon energy source'. Dempsey (2019).

- in countries where energy demand is rising rapidly and carbon reduction is not close to the top of the policy agenda, affordability of unabated (particularly imported) gas and LNG is already a problem which has resulted in increased coal-fired power generation.

Why focus on LNG rather than pipeline gas?

Similar considerations apply to new long-distance, large scale international pipelines but very few of these are either under consideration or construction worldwide. The only such pipelines under construction are:

- Russia to Europe (Nord Stream 2 and Turk Stream), where Gazprom's market is already established;
- Russia to China where otherwise (largely) stranded gas is being exported to a rapidly expanding market. The Power of Siberia pipeline will start operating in December 2019.
- Azerbaijan to Turkey and onwards through Greece and Albania to Italy (TANAP/TAP pipelines) which will be completed in 2020.

Other long distance international pipelines under active discussion include those from Russia to China (Power of Siberia 2/Altai and Far East/Sakhalin), Turkmenistan-China (Line 4), Turkmenistan-Afghanistan-Pakistan India (TAPI), and East Mediterranean (Israel-Europe).[6] It is not clear whether these pipelines will be built, or whether they will be the only new pipelines to be built in future, only that most other large scale (>10 bcma) international projects which have been under discussion for a long time, seem highly unlikely to progress.[7] Moreover, any new pipeline projects aimed at Europe which have not yet reached FID and started construction would already need to take decarbonisation into account which would further complicate their already difficult economics and politics.[8]

The reason this paper looks in more detail at the challenges for LNG projects is that these are projected to account for around 80 per cent of the increase in global gas trade up to 2040.[9] As governments begin to formulate their plans to achieve their 2050 decarbonisation targets, these become an increasingly important consideration for LNG projects. This will be particularly relevant for projects with potential recourse to Europe as a market of last resort where governments appear likely to increase the stringency of carbon reduction targets. New – and indeed existing – pipeline gas projects may face similar challenges to reduce their greenhouse gas footprint, but for LNG this could become a global challenge whereas for international pipeline projects it will be geographically specific.

The propositions of this paper are that:

- By the late 2020s limits could be placed on sales of unabated LNG in carbon-sensitive countries, particularly in the high wholesale price markets of Europe (and possibly some in Asia);
- Reducing the greenhouse gas footprint, and the eventual decarbonisation, of LNG will become increasingly urgent for projects intending to deliver to these markets;
- Carbon reduction will have an increasingly significant impact on the planning and potential costs of LNG projects;

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[6] In some accounts Turkmenistan-China (Line 4) is under construction; in July 2019 a meeting between CNOOC and Uzbekneftegaz proposed bringing forward the start of construction, Argus (2019). In September 2019, the TAPI partners announced that they expected the project to reach financial closure in early 2020. Sharma (2019).

[7] For example the Iran-Pakistan and Iran-India pipelines, Jalilvand (2019).

[8] The main pipelines which have been suggested are a significant expansion of the existing TANAP/TAP network from Azerbaijan (possibly to include gas from Turkmenistan) and the East Mediterranean pipeline from Israel to Greece and then to a variety of EU countries.

[9] IEA, WEO 2017, Figure 8.11, p.362. To be specific the data refer to inter-regional gas trade, i.e. do not include trade between countries in the same region.

- For lower wholesale price gas markets, LNG prices significantly above $6/mmbtu may be problematic, and prices above $8/mmbtu may rule out any significant expansion of imports for these markets because the required subsidies may be too large for governments to sustain. Where (especially domestic) coal is still a major factor in energy balances, prices significantly above $8/mmbtu will also curtail demand in price-sensitive gas markets;
- A combination of these two issues could lead to profitability problems for new – and potentially also existing – LNG projects suggesting an urgent need for greater clarity about carbon reduction policy and affordability/price elasticity in importing countries.

The paper is structured as follows. Following this introduction, the second section looks at national and regional projections of gas demand consistent with COP21 carbon reduction targets. The third section examines the problems of measuring greenhouse gas emissions from the LNG value chain. The fourth section examines how LNG projects should prepare for future emission standards and certification requirements, and carbon reduction options for exporters and importers along the value chain. The fifth section looks at the affordability of LNG in relation to wholesale gas prices over the past decade in countries currently importing (or with firm plans to import) LNG, and contrasts these price levels with cost estimates for new LNG projects. The final section summarises and draws conclusions.

2. Regional Gas Demand Projections Under COP21 Reduction Targets

LNG projects are capital-intensive and expect to recover their costs over a period of ten or more years after the start of production.[10] An LNG project which takes its FID in 2019-20, would expect to start operations around 2024-25 and run for at least 25 years.[11] This means that new LNG projects will be expected to operate up to and beyond 2050 – the date by which very substantial decarbonisation will need to have been achieved under COP21 targets.

COP21 and gas demand – regional projections to 2050

Previous publications provided detail on the range of available public domain projections of gas demand which are compatible with carbon reduction targets.[12] Figures 1 and 2 show projections from the Shell Sky Scenario and the Equinor Renewal Scenario both of which extend to 2050[13] (the Sky scenario extends to 2100) and are compatible with COP21 targets of reducing carbon emissions to 'well below 2 degrees', which provide an illustration of data differences and uncertainties which are relevant in the context of this paper.

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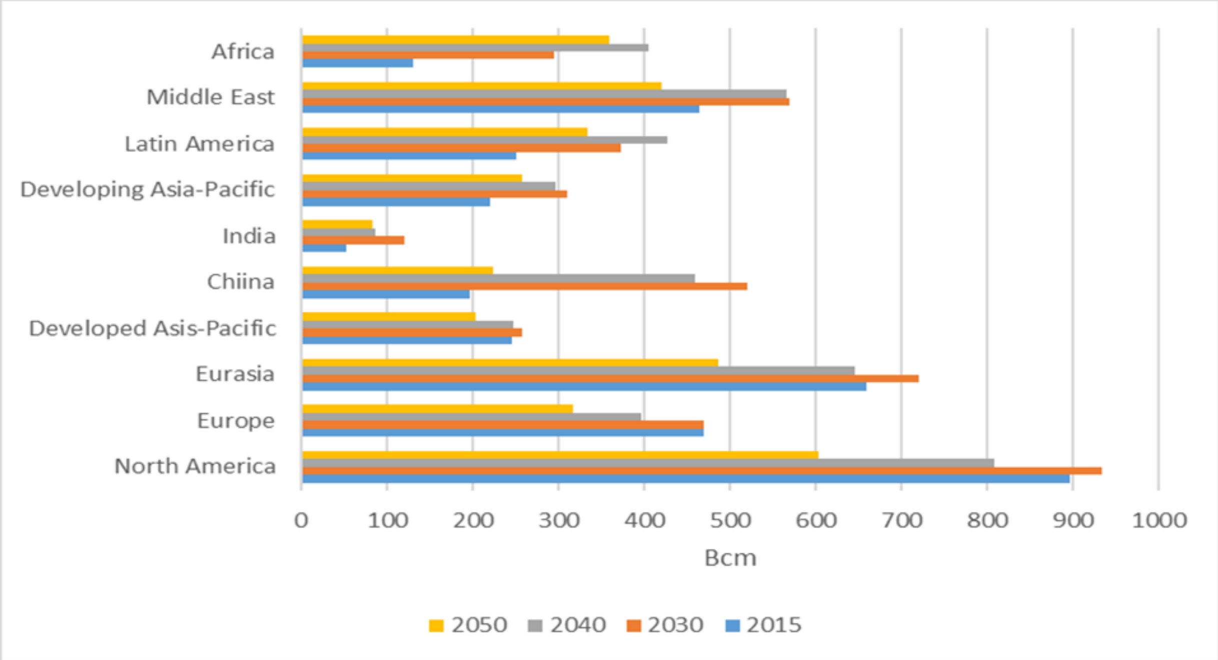
[10] Cost recovery times will vary from project to project, but ten years can be regarded as a minimum in most cases. A distinction needs to be made between payback times in cash terms and earning the required rate of return, including paying off any debt which has been incurred.

[11] Lead times can be less than five years for brownfield (conversion of import to export terminal) projects. The time required for building tanks with full containment is usually the determining factor.

[12] Stern (2017b) and Stern (2019a).

[13] Projections with horizons prior to 2050 may give a misleading impression of demand reductions required to meet targets. CEPS (2019), Figure 2, p.12 cites a wider range of 2050 gas demand scenarios for Europe.

Figure 1: Natural Gas Demand in Different Countries and Regions Compatible with COP21 Targets 2015-50

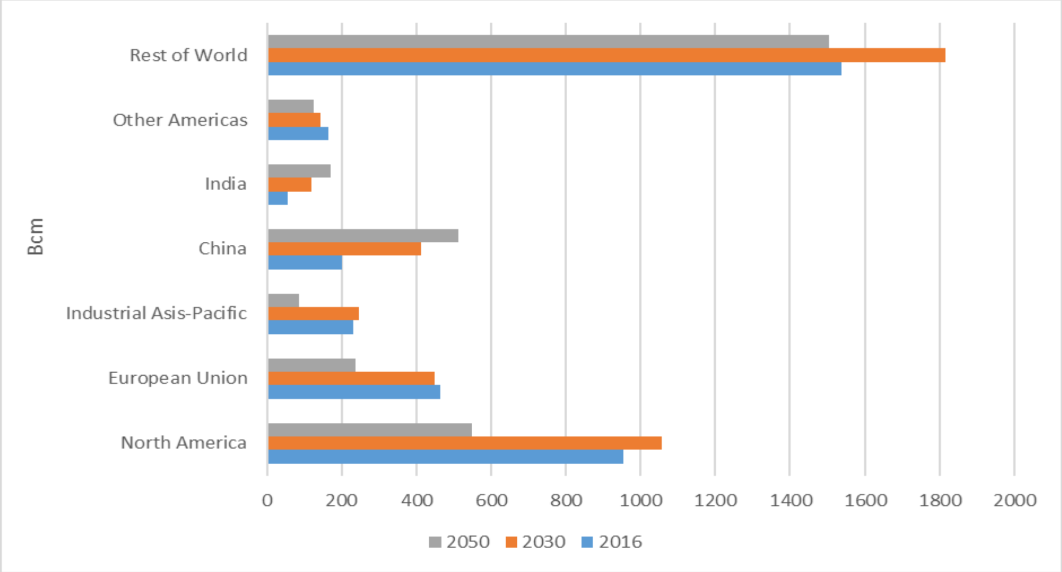


Source: Shell Scenarios, SKY – meeting the goals of the Paris Agreement (2018).

Although there is a less than five per cent difference between the two projections of global gas demand in 2050, there are some major regional differences which (even allowing for differences in regional definitions) are significant:

- Shell sees European natural gas demand in excess of 300 bcm in 2050 while the Equinor figure is 80 bcm lower (although this may be partly due to differences in regional definitions between EU and 'Europe');
- Shell sees Chinese gas demand rising over 500 bcm in 2030 and then falling sharply post-2040 to less than half that figure by 2050. Equinor sees Chinese demand at just over 400 bcm in 2030 and increasing by 100 bcm in 2050.
- Both projections see Indian demand at 120 bcm in 2030, but in the Sky scenario this declines to just over 80 bcm, while in Equinor's projection it rises to 170 bcm by 2050;
- Asia-Pacific demand in 2050 is projected at 200-250 bcm by Shell, but Equinor sees this falling to less than 100 bcm by that date.

Figure 2: Natural Gas Demand in Different Countries and Regions 2016-2050, Equinor Renewal Scenario



Source: Equinor Energy Perspectives (2019) data appendix.

For projects trying to work out where they might be selling their LNG over the next three decades this is a confusing picture but with the anticipated increase in short-term trading, it is increasingly likely that demand can be found somewhere in the world. A determining factor may be the price which LNG can command in different markets relative to the costs of delivery of individual projects, and we return to these issues in Section 5.

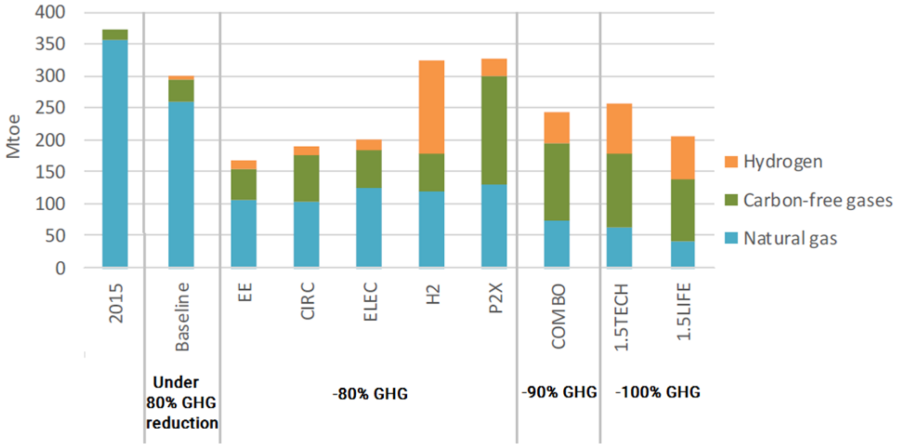
A possible conclusion from these projections is that LNG exporters could regard the period up to 2040 in many parts of the world as 'business as usual', in other words that carbon reduction will not significantly impact natural gas demand worldwide and their ability to sell cargos of unabated LNG. However, in the high price (and therefore high value) markets of Europe (and potentially some Asian countries) the likelihood is that by the 2030s governments will progressively require the decarbonisation of natural gas or its replacement by low or zero carbon gas (biogas/biomethane, or hydrogen sourced from renewable energy or reformed natural gas with CCS).

It is also important to recognise that some governments have committed, and others are considering committing, to net zero carbon emissions by 2050 (and potentially before that date). Net zero emissions would require a considerable reduction in natural gas demand from the figures in the Shell and Equinor projections. European Commission projections see only 45-60 bcm of natural gas being compatible with net zero emissions for the EU by 2050, in the context of total EU gas demand (including zero carbon gas and hydrogen) of 200-250 bcm (Figure 3). Therefore in order to be compatible with net zero targets, decarbonisation of natural gas – including LNG imports – would need to be substantially speeded up. There is a growing focus on the EU targets for 2030 and whether these will be made more stringent if a net zero target is adopted for 2050, either for the EU as a whole or in individual member states.[14] Should this happen, the projections (in Figures 1 and 2) that natural gas demand will remain relatively flat or decline only slightly during the 2020s would be far too optimistic.[15]

[14] Geden and Schenuit (2019) note that: 'Although it is not mandatory to step up efforts by 2030, failure to do so would damage the EU's credibility...a 40 per cent reduction by 2030 is not compatible with the goal of greenhouse gas neutrality by 2050. This would require an enormous increase in ambitions after 2030, which hardly seems feasible.'

[15] In the UK National Grid's 2019 scenarios there is a big role for hydrogen from natural gas reforming with CCS, particularly if the net zero target is to be met in 2050. National Grid (2019), Figure 6.4, p.156.

Figure 3: EU Gas Scenarios for 80-100 per cent of GHG Reductions in 2050[16]



Source: CEPS (2019), Figure 3, p.13, based on European Commission (2018) Figure 33, p.85.

3. Methodology, Measurement and Regulation of CO2 and Methane Emissions in the LNG Value Chain

One of the most difficult issues surrounding the compatibility of natural gas and LNG with greenhouse gas reduction is the measurement of carbon and methane emissions from the gas value chain. Methane emissions have been discussed in previous publications and a significant literature has evolved on the contribution of methane to greenhouse gas emissions, specifically 'fugitive' methane from natural gas operations and (resulting from this) the extent to which coal to gas switching should be considered beneficial in terms of overall emissions.[17]

The LNG value chain has not attracted significant attention in this literature but this may change due to the expansion of trade, and especially the increase in US LNG exports, over the next decade.[18] Emission factors for much of the LNG value chain – exploration, production, pipeline transportation, and the end use of the gas – are common to those for natural gas utilisation in general, whether used domestically or exported by pipeline. Those which are specific to LNG are liquefaction, shipping, and regasification. A particular feature of the LNG chain is the ability (which is not always the case with pipeline gas) to identify very specifically the country of origin of the gas and the facilities (including the field from which the gas was produced) through which it has passed to reach its destination.[19] It is therefore possible to calculate the greenhouse gas footprint of an LNG cargo delivered to a specific destination with a reasonable degree of accuracy, and governments and regulators in some countries have already created some of the building blocks for such calculations.

Public domain literature uses generalised leakage factors for natural gas and LNG, usually from the US where most of the publicly available data and estimates originate. Much of the public literature on natural gas emissions – both methane and carbon – takes a figure, usually from a survey of several US sources extended to a national figure through modelling, and then generalises the figure

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[16] Descriptions of the scenarios can be found in European Commission (2018), pp. 53-56.

[17] In addition to the question of the figure which should be adopted for radiative forcing of methane and over what time period: the IEA uses figures of 85 over 20 years and 30 over 100 years. IEA (2018), Box 11.3, p.490. But estimates for the 20-year time frame can be as high as 87 and for 100 years up to 36. IEA (2017), Box 10.2, p.405; Balcombe et al. (2015) p.16; Stern (2017b), Appendix 4; Stern (2019a) Appendix A; LeFevre (2017).

[18] An exception is Balcombe et al. (2015), Figures 14 and 18, pages 35 and 43, and Table 6, p.71, which gives methane and CO2 emission estimates for each element of the gas and LNG value chain.

[19] Guarantees of Origin are relatively straightforward but in the US, where gas is often accessed from the network rather than from a specific field, certification of upstream emissions will be less precise.

worldwide.[20] High emission figures provoke protests from natural gas stakeholders who cite lower figures from other studies and corporate commitments and initiatives which have been undertaken – including OGCI, Methane Guiding Principles, Oil and Gas Methane Partnership, Collaboratory to Advance Methane Science (CAMS), Marcogaz/GIE and ONE Future – to reduce (particularly) methane leakage and promote carbon capture and storage (CCS[21]).

However, as previous papers observed, common standards, measurement methodologies, and transparent data sources, are taking a very long time to put in place. Emission reduction commitments by companies can only cover their own operations, rather than the whole value chain. The past two decades of liberalisation and unbundling have fragmented the natural gas value chain making cooperation very difficult because of diverging commercial interests.[22] Moreover, establishing transparent methodologies for verifying especially methane emissions which can be independently certified will be an important part of any future natural gas and LNG sustainability narrative.

Estimating emissions from different elements of the LNG Chain

There is a growing literature on natural gas emissions. The International Energy Agency (IEA) has a database of emissions which breaks down the 80kt of global methane emissions from global oil and gas operations into vented, fugitive, and incomplete flares.[23] It estimates that 40 per cent of these emissions originated from onshore and offshore oil production, nearly another 40 per cent from offshore and onshore gas production, with downstream gas accounting for nearly all the remaining 20 per cent. Of the total emissions, more than 70 per cent would be possible to abate, and nearly 40 per cent of emissions could be abated at no net cost.

Liquefaction of gas is an energy-intensive process because of the need to cool the gas to minus 162 degrees C. The IEA estimates that taking into account the entire value chain for delivery of US LNG to Europe, around 11 per cent of the gas arriving at the liquefaction terminal would be combusted and therefore emitted as CO2 (not methane[24]). Wood Mackenzie suggest that: '...the losses (largely as fuel) of natural gas along the LNG value chain can account for more than 12-13 per cent of the original hydrocarbon gas produced at the wellhead; this is compared with less than 1 per cent for a typical pipeline project'.[25] The high degree of uncertainty surrounding GHG (especially methane) emissions from LNG is due to a lack of data from specific 'field to regasification terminal' value chains.

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[20] An example of this is Nace et al. (2019) which uses emission factors from Alvarez et al (2018). See also Abrahams et al (2015). For US studies using both top-down and bottom-up methodology see IEA (2017), pp. 403-13. The most complete study of the methane emissions literature up to 2015 is Balcombe et al (2015). A recent US study suggests that North American shale gas production 'may have contributed more than half of all of the increased emissions from fossil fuels globally and approximately one third of the total increased emissions from all sources globally over the past decade'. Howarth (2019).

[21] Oil and Gas Climate Initiative (OGCI), http://oilandgasclimateinitiative.com/; Methane Guiding Principles http://ccacoalition.org/en/resources/reducing-methane-emissions-across-natural-gas-value-chain-guiding-principles; Collaboratory to Advance Methane Science (CAMS) https://methanecollaboratory.com/ Marcogaz (2019), ONE Future, http://onefuture.us/ LNG export assets are included in the facilities being surveyed for emission reduction, Climate and Clean Air Coalition, (2018), p.12.

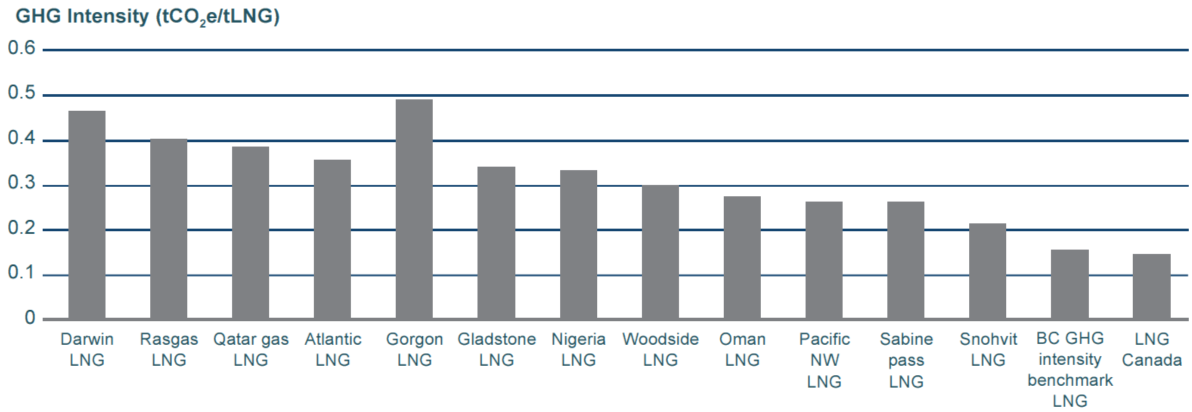
[22] Value chain fragmentation is explained in detail in Stern (2017a), pp. 15-17.

[23] https://www.iea.org/weo/methane/database/ The database includes nearly 80,000 entries from a very large number of countries itemised by upstream and downstream and divided into fugitive, vented and incomplete flaring.

[24] IEA (2018), p.488.

[25] WoodMac (2017), p.1.

Figure 4: Greenhouse Gas Emissions from Selected LNG Liquefaction Plants*



*Emissions from entry into liquefaction plant to the loading arm of the LNG ship.
Source: Calitz (2019).

Progress towards verifying emissions from the LNG value chain has been achieved in countries where achieving a defined level of emissions from the liquefaction process is required as a condition of regulatory approval of the project. Figure 4 is from a presentation by LNG Canada showing greenhouse gas emissions from a range of liquefaction plants compared with the British Columbia (BC) GHG intensity benchmark of 0.16 tonnes of CO2 equivalent per tonne of LNG produced.[26] Failure to meet this benchmark requires the purchase of 'compliance units' (see Section 4 for details). It should be emphasised that the BC legal framework includes only emissions from the liquefaction plant to the loading arm of the ship, and not emissions from exploration, production, and transportation of gas to the liquefaction plant. BC emissions from gas production are estimated to fall up to around 2024 and then increase until the end of the decade, before levelling off and slowly falling over the 2030s.[27]

Many (but not all) of the statistical building blocks are in place for those importing from the LNG Canada project to make a rough (although currently not exact) estimate of the GHG footprint of the LNG which they will be receiving. They would also need estimates of upstream emissions from exploration and production of the Montney shale play (which is the source of the gas for the project), plus emissions from the 670km pipeline which transports the gas from the production site to the LNG terminal.

After liquefaction, the final element of the value chain before the LNG reaches its destination is the shipping. LNG ships are of different sizes and the type of propulsion depends on the size. In 2017, the global carrier fleet of ships below 125,000 cubic metres (m3) LNG capacity were powered by steam turbines; 85 per cent of ships between 125,000 and 180,000 m3 capacity are steam turbine or tri-fuel diesel; and 96 per cent of ships above 180,000 m3 capacity were slow speed diesel.[28] The Thinkstep study gives methane emissions for all types of carriers in relation to boil-off gas from cargo tank to engine, and methane slip during fuel combustion.[29] It also gives sea distances from the main LNG exporters to the main market destinations for the different types of carriers used, but these are relevant only if cargos travel directly from a specific location to a specific destination whereas, in an increasingly liquid traded LNG market, cargos may change direction several times prior to final delivery. This will mean that accurate emission estimates can only be obtained by calculating the

[26] British Columbia (2019). This figure applies to 'LNG operations' defined as: 'virtually all GHG emissions from the point where natural gas enters an LNG operation via pipeline, to where the LNG is loaded onto a ship, train or other transportation facility for delivery to market'. All electricity offsite will be included in the reported GHG emissions.
[27] CERI (2019), Figure 3.15, p.77. This data set includes emissions from the following activities: drilling, production and extraction, processing in the field, and venting, flaring, and fugitive emissions from those activities but not emissions from transportation.
[28] Thinkstep (2019), Tables D12-D14, p.130. More detail on carrier types can be found in Rogers (2018) and Steuer (2019).
[29] Thinkstep (2019). Tables D15-D16, p.131.

length of the individual voyage of a specific cargo when it arrives at its destination, and an agreed daily emission factor for the specific LNG ship.

The main point of this discussion is to show that generalised estimates of emissions derived from the modelling of limited empirical data of GHG emissions from gas and LNG operations from a single country (usually the US) are of limited value. The principal way for LNG stakeholders to achieve credibility for their GHG emission footprint will be to provide empirical data from a specific LNG value chain up to the point where the LNG is unloaded at the regasification terminal. It will then be for the country where the LNG is landed to estimate emissions from the regasification terminal and transportation to the final end user of the gas.

4. Emission standards and certification requirements for LNG

Regulation of emissions in exporting countries

The example of LNG Canada shows how governments in exporting countries may impose emission limits on new projects, but Canada was not the first country to make such requirements. The Snohvit LNG project in Norway has been operating since 2008 with CCS at the field.[30] In Western Australia a CCS facility was part of the conditions for developing the Gorgon LNG project.[31] The CCS element of the project was commissioned in August 2019 following a delay of several years after the start of LNG deliveries.[32] The extent to which new West Australian LNG projects currently under consideration will be required to either sequester or offset emissions is currently unclear.[33]

The decision by the Trump Administration to withdraw from the Paris Agreement and promote LNG exports means that the federal government will not impose limits on greenhouse gas emissions from US projects.[34] But the Federal Energy Regulatory Commission's (FERC) environmental assessments include GHG emission estimates[35] and two of the four Commissioners have expressed concern about this aspect of the projects.[36] Commissioner Glick has dissented in very strong terms from a number of FERC's public interest orders for LNG projects on the grounds that they fail to take into account climate change consequences.[37] Commissioner LaFleur, while concurring with these orders wrote: 'I remain frustrated by the Commission's continued refusal to even consider how we might develop a framework for assessing the potential significance of GHG emissions.'[38] She added '...using the social cost of carbon could enable the Commission to assess the significance of GHG emissions…While making a significance determination on GHG emissions could be difficult, that challenge does not relieve the Commission of its responsibility to address this issue.'[39] While these opinions have thus far made no difference to the approval of US LNG projects, they are an indication of regulatory concerns about the GHG aspects of these projects which, under a different Administration, could become significant.

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[30] https://www.equinor.com/en/what-we-do/natural-gas.html

[31] *Gorgon Gas Development and Janz Feed gas Pipeline: greenhouse gas abatement programme*, May 2015, https://australia.chevron.com/-/media/australia/our-businesses/documents/gorgon-emp-greenhouse-gas-abatement-program.pdf

[32] Le May (2019).

[33] Morton (2019).

[34] This is important because more than half of the global total of projects seeking to take FID in 2019 and 2020 are in the US (although the actual number which will succeed – both in the US and globally – will be much less). Steuer (2019), Table 1, p.4. But also became of the claim that methane emissions from North American gas operations are largely responsible for very substantial increases in global methane and greenhouse gas emissions (see note 20). Howarth (2019).

[35] For example the Corpus Christi assessment includes emissions from the pipeline and LNG terminal (but not the rest of the value chain) during construction, start-up and operations. FERC (2019), Tables B.8.1-5 to B.8.1-8, pp. 123-6.

[36] At the time of writing there were only four FERC Commissioners.

[37] Specifically, the Dominion Cove Point, Venture Global Calcasieu Pass and Driftwood LNG projects. Glick (2018) and (2019).

[38] LaFleur (2019a).

[39] LaFleur (2019b).

Standardisation and certification of emissions

Standardisation and certification by regulatory or recognised certification authorities will be the only way to achieve credibility of emissions' estimates from the different elements of individual value chains.[40] The emissions needing to be certified will be:

- Gas (or oil) well to loading arm:
    - exploration and production per unit of output,
    - pipeline transportation per kilometre to the liquefaction terminal,
    - liquefaction per unit of LNG produced and exported;
- LNG ship to regasification terminal: specific ship type per kilometre travelled;
- Regasification terminal to combustion: emissions per unit of regasified LNG + pipeline transportation per kilometre to end-user + emissions per unit of gas burned (by power/industrial or distribution company).

Standard emission factors per unit of production, throughput and distance, will need to be established for each element in each project: production, transmission, liquefaction terminal, type of ship and regasification terminal. Other elements should remain relatively constant although technological advancement for example using renewable electricity to power the liquefaction process, will be important.[41]

This could suggest the need for three different certification authorities in the producing/exporting country, shipping, and importing country. An alternative would be for a single company to certify emissions from a specific value chain. Acceptance of the need for certification and the methodology of estimation will be key issues. Like fossil fuel reserves, emissions will need to be certified by a recognised company or government/regulatory agency. Some producers may be unwilling to submit to external certification of emissions, insisting on national estimates which may not be acceptable to environmental stakeholders in importing countries. A specific methodological issue is whether to measure emissions at ground-level ('bottom-up') or atmospheric ('top-down') levels or some combination of the two.[42]

There may need to be different certification authorities for different parts of the LNG value chain[43]:

- Exploration, production, and transmission to the liquefaction terminal: national regulator or recognised certification company;
- Liquefaction terminal: national regulator or recognised international certification company;
- Shipping: recognised shipping certification company;
- Regasification terminal, transmission, and end-use: national regulator or recognised certification company.

[40] Similar requirements should (and probably will eventually) apply to all fossil fuels and the intention is not to single out LNG to the exclusion of other fossil sources which could have similar or higher emissions. But given the likely increase in LNG imports from remote sources, documentation of emissions is likely to become important in a shorter time frame.
[41] The Snohvit plant uses hydroelectric power. Future Canadian LNG plants may have even lower emissions than LNG Canada (which uses aero-derivative turbines) with the Kitimat LNG project proposing to become an "all-electric plant" powered by hydroelectricity. Pearson (2019).
[42] Balcombe et al (2015), pp. 16-17; IEA (2017), pp.403-4 and 409-10.
[43] Examples of authorities currently being used by upstream companies are: KPMG acting as an independent practitioner providing a 'Limited Assurance Report' on Gazprom's CO2 and methane emissions, Gazprom (2019), p.26 and 79-83. BP's Sustainability Report includes an Independent Assurance Statement from Deloitte LLP, BP (2019c), p.78. Shell's Net Carbon Footprint methodology will be certified by Lloyds Register Quality Assurance. Shell (2019a).

Certification may not be straightforward, particularly where gas production and transportation assets cannot be specifically attributed to an LNG project.[44] But stakeholders should expect to provide detail in relation to emissions from individual elements of LNG value chains.

Confidentiality and transparency

In order to achieve credibility for its GHG footprint, the LNG community will need to provide complete transparency of both emissions data and the methodology used to compile them. This may create difficulties for an industry where data confidentiality has been standard operating procedure, but nothing less will be acceptable (and accepted). For many environmental organisations, industry 'confidentiality' will be interpreted as hiding high levels of emissions and 'greenwash'. Very high and generalised emission claims from environmental (and other) groups, referred to above, which receive wide publicity in the media, can only be countered by certified emissions from organisations with substantial data-gathering capability and impeccable independence credentials.

Carbon reduction options for exporters and importers

LNG exporters have a number of options when faced with the challenges of decarbonisation. These challenges depend on whether regulation originates from the exporting or importing country. In some exporting countries compliance with emission standards may be the only way to receive regulatory approval for a liquefaction project. For the Gorgon LNG project in Western Australia this was achieved by requiring CCS. In British Columbia (Canada) the Greenhouse Gas Industrial Reporting and Control Act also allows offsets and carbon emission payments to achieve compliance with emission standards:[45]

> 'The…Act combines several pieces of existing greenhouse gas legislation into a single legislative framework. It includes the ability to set a greenhouse gas emissions intensity benchmark for regulated industries, including LNG facilities and enables the benchmark to be met through flexible options, such as purchasing offsets or paying a set price per tonne of greenhouse gas emissions that would be dedicated to a technology fund.
>
> `The Greenhouse Gas Emission Administrative Penalties and Appeals Regulation establishes the process for when, how much, and under what conditions administrative penalties may be levied for non-compliance with the act or regulations.
>
> `The Greenhouse Gas Emission Control Regulation[46] establishes the BC Carbon Registry and sets criteria for developing emission offsets issued by the Province. The regulation also establishes the price ($25) for funded units issued under the act that would go towards a technology fund. Regulated operations, such as LNG operations, will purchase offsets from the market or funded units from the government to meet emission limits.'

A more radical option for exporting countries seeking to meet emission requirements would be to decarbonise the gas in their own countries and ship hydrogen or ammonia, rather than LNG, but this would require CCS in the exporting country.[47] The first large scale hydrogen shipments will be from

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[44] For example where the gas may be coming from different (oil or) gas wells with different characteristics and where there could be different pipeline routes to an LNG terminal; this might be particularly applicable in the US. Thinkstep (2019) Annex D, provides detail by country for energy use and gas losses from conventional and unconventional gas production, processing and transportation to liquefaction plants in: Algeria, Australia, Indonesia, Malaysia, Nigeria, Norway, Qatar, Trinidad and Tobago, and the USA.
[45] Greenhouse Gas Industrial Reporting and Control Act (GGIRCA) which came into force on January 1, 2016 https://news.gov.bc.ca/releases/2015ENV0084-002116
[46] http://www.bclaws.ca/civix/document/id/lc/statreg/250_2015
[47] There are other options which would all involve higher capital expenditure but fewer greenhouse gas emissions: shipping LNG at pressure would not require such heavy refrigeration which would be a big change requiring new ship and onshore storage with full containment tanks; shipping methane absorbed in a carrier fluid; and compressed natural gas shipped in 250 bar steel pipes.

Brunei to Japan starting in 2020.[48] Shipping liquid hydrogen is complicated as it needs to be cooled to minus 253 degrees C (significantly lower than the minus 162 degrees required to liquefy natural gas). Ammonia is substantially easier to transport than hydrogen but would then require reconversion to hydrogen.[49]

LNG exporters could also consider progressively replacing methane with biogas and biomethane feedstock, depending on availability in excess of local demand. Initially this may not be practical as projects are usually based on a large reserve of discovered methane, very often offshore. But depending on the availability of low or zero carbon gas, a phased introduction into the LNG feedstock may be possible over time and certainly after the expiration of the initial contract term. This should be an important consideration for many existing projects which are intending to extend production beyond the term of the original contract.

However, any substitution of natural gas imports by biomethane, reformed natural gas to hydrogen (with carbon capture utilisation and storage - CCUS), or power to gas will result in significantly higher delivered LNG costs.[50] As present these, and additional options such as liquefied hydrogen or ammonia, appear to be part of a 'rich country' paradigm, determined at a policy level, whereby the energy balance moves to renewables plus a range of low and zero carbon gases. These additional costs would need to be met by some mixture of prices paid by consumers for power and hydrogen, or through carbon-specific or general taxation.

Importing governments may impose emission standards on deliveries of unabated, imported natural gas and LNG as part of their GHG reduction targets.[51] This will probably happen first in Europe, particularly in the large gas markets[52] which imported around 70 per cent of European LNG in 2018 and where government policy is most carbon-centric, but it is also possible in Asian countries (particularly Japan).

When LNG arrives in an importing country it can be decarbonised after regasification by (steam or auto-) reforming into hydrogen with CCS.[53] Offshore structures (depleted fields or aquifers) would be required for CO2 storage and offshore pipelines for CO2 transport.[54] This would also require coordination with (onshore) transmission system operators to develop new hydrogen networks or to blend hydrogen into existing methane networks.[55]

It is not too early for LNG projects – and particularly those projects yet to take FID – to prepare for future requirements to decarbonise their cargos, even if such requirements are not introduced until the 2030s and even if they are not yet visible in the policies, laws, and regulations of importing governments. It is highly likely that emission constraints will be introduced during the life of all projects

[48] Chiyoda (2018). Although in this case the gas will be liquefied before being converted to hydrogen. There is another Japanese project to import coal-based hydrogen from Australia in the early 2020s, and plans to create hydrogen export hubs on both the west and east coasts of Australia. Bogle (2018). An estimate of costs for a range of options to produce hydrogen in Australia with shipping to Japan can be found in IEA (2018), Box 11.6, pp.510-11.

[49] The technical and economic options around whether to ship pure hydrogen or a liquid organic hydrogen carrier (a LOHC such as methylcyclohexane) or ammonia are complex. For details of the complexities connected with the shipping of hydrogen, LOHCs and ammonia see IEA (2019b), pp.74-78.

[50] For indicative costs of these technologies in general and in different countries, see Lambert (2018), IEA (2019b), Chapters 2-4.

[51] Such restrictions would logically also apply to pipeline gas – whether domestically produced or imported – which would arguably create greater problems for very large exporters such as Russia, Norway, and Algeria with fixed delivery infrastructure and limited alternative export options.

[52] UK, France, Germany (which plans to become an LNG importer), Italy, France, Netherlands, and Belgium.

[53] Steam and auto reforming removes 90-95 per cent of CO2 and thus does not completely decarbonise methane. An alternative method of producing hydrogen via pyrolysis – or methane splitting – has yet to be commercially proven but is worth monitoring as it may simplify carbon storage. Poyry (2019).

[54] In most European countries it is not possible to store carbon dioxide on land for political reasons (often backed by legislation), and offshore storage structures may either be lacking or commercially unviable.

[55] For blending issues and current limitations in different countries see IEA (2019b), pp.70-74. For more general impacts of decarbonisation on transmission networks see LeFevre (2019).

which will continue operating post-2030. Prudent project developers should plan to have their carbon and methane emissions for the entire value chain up to unloading at the regasification terminal certified by reputable authorities, and to take note of requirements and standards being imposed elsewhere.

The adoption of legal/regulatory frameworks for GHG emissions by importing countries would mean that non-certified LNG, or LNG which failed to meet these standards, would need to make offset arrangements or carbon payments, or seek other markets. This will be particularly important for sellers wishing to take advantage of liberalised access to liquid European spot markets where it is always possible to sell a cargo when markets elsewhere may not be available.[56]

Methodologies for emission standards may take several years to establish for the different elements of each LNG value chain. But cargos which do not have value chain certification by accredited authorities, or which fail to meet certain emission standards, run the risk of progressively being deemed to have a lower value (because they will require the buyer to purchase higher levels of emission offsets of various types) or eventually excluded from jurisdictions with strict regulatory standards.

5. Affordability and Costs of New LNG Projects

A key conclusion of previous research was that: '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.'[57] The price parameters advanced in that paper were that, in order to remain affordable, gas must be delivered to high income countries at below $8/mmbtu and low income countries at below $6/mmbtu.[58] This conclusion was based on a ten year data set from the International Gas Union on natural gas prices in more than 100 countries. Here we update that data to 2018 in order to examine what has happened to wholesale prices in LNG importing countries and the costs of new LNG projects.[59]

Wholesale gas prices over the past decade in countries currently importing (or with firm plans to import) LNG

Figures 5-12 show gas wholesale gas prices for different regions of the world, and countries in those regions which are importing, or in the future may import, LNG for the period 2005-18. The data are taken from the International Gas Union (IGU) wholesale gas price surveys for the respective years. The main limitations of the data are that they are expressed in actual (nominal) prices for the year taking no account of inflation and then converted into US dollars at the exchange rate for the year in question. Therefore year-to-year price changes may reflect foreign exchange rate fluctuations rather than actual movements in national price levels.[60] These figures do not capture the post-2018 period when international LNG and gas prices fell to very low levels (to which we return later in this section).

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[56] In Asia, JERA and Shell have already announced voluntary renewable energy and forest-based offsets of GHG emissions for a limited number of LNG cargos delivered to India and Japan (respectively). The JERA project involves only end-use emissions from power generation while the Shell project is for emissions for the entire value chain. JERA (2019); Shell (2019b).

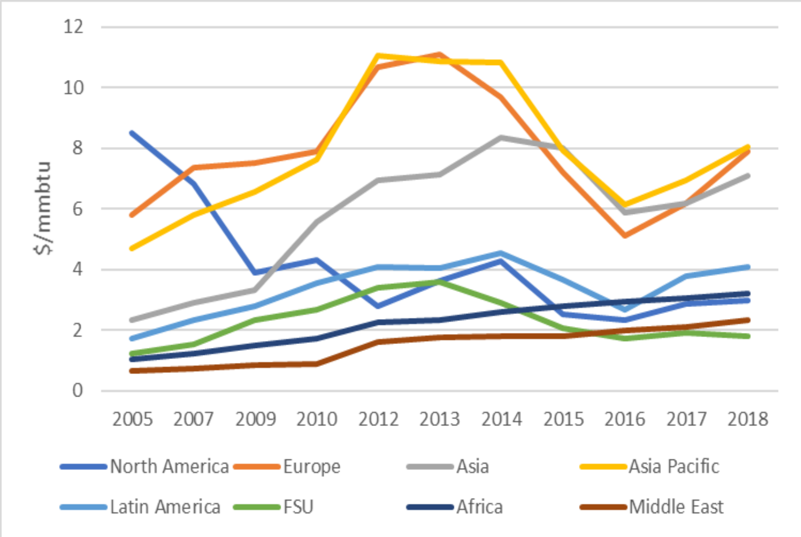
[57] Stern (2017b).

[58] Those prices were in 2017 dollars, but the same levels are still applicable in 2019 despite wholesale price increases in many low income countries in the intervening period.

[59] The two parameters of affordability are: an absolute price level 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.

[60] See Stern (2017b), Box 1, p.11 for details. In addition, the prices in these figures are averages for all users during the year which hides significant differences in low and high prices for different user groups.

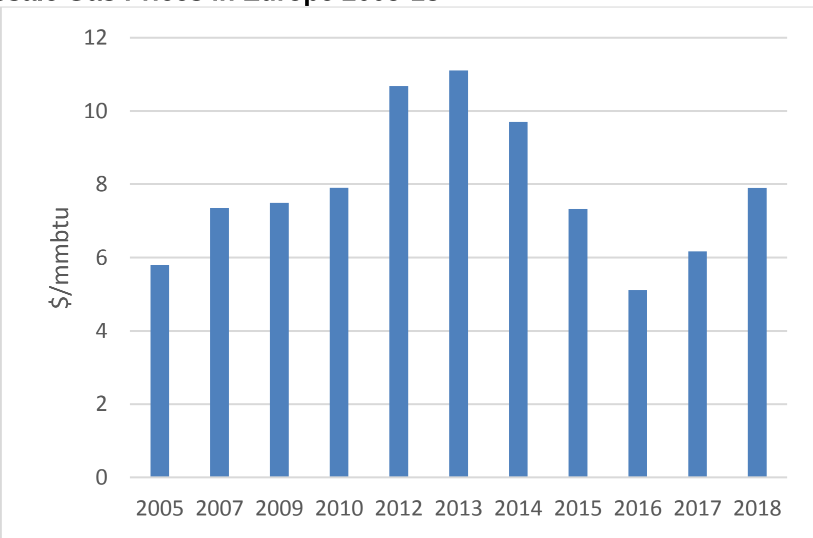
Figure 5: Wholesale Gas Prices in Different Regions 2005-18



Source: IGU (2019), Figure 4.5, p.48.

The regional data in Figure 5 show wholesale prices of gas for the period 2005–18, from which it is clear that there are two distinct regional groupings: those that have paid prices in excess of $6/mmbtu over an extended period of time (Europe, Asia, and Asia Pacific[61]), and others (aside from North America prior to the shale gas revolution) where prices have never exceeded $4/mmbtu. Since 2016, regional price levels have diverged somewhat following a five-year period of convergence. It is not clear how the sharp fall in 2019 international prices levels will impact the regional picture. However, the main point is that there is 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). Nevertheless, the regional data conceal important differences between countries which are illustrated in Figures 6-12.

Figure 6: Wholesale Gas Prices in Europe 2005-18



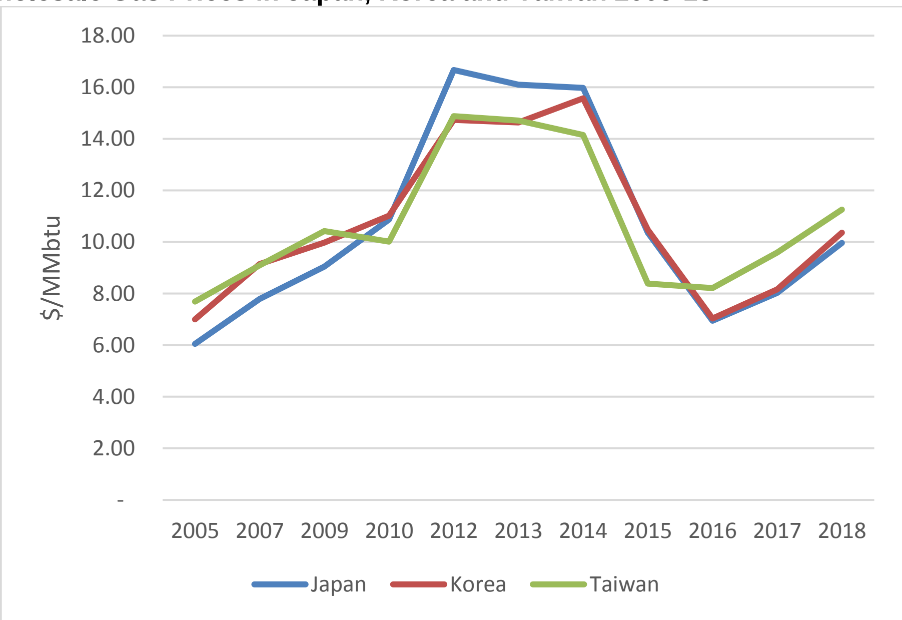
Source: IGU, Wholesale Gas Price Survey for respective years.

[61] The IGU regional definition for Asia includes: China, India, Pakistan, Bangladesh and Myanmar. Asia Pacific comprises: Japan, Korea, Taiwan, the rest of south east Asia, and Australasia.

Figure 6 shows European wholesale prices which have generally been in the $6-8/mmbtu range over the past decade. We do not show individual country prices for Europe because, since 2014 and going forward, wholesale prices in the *major* LNG importing countries (with the exception of Spain, Portugal, and Turkey) are set by the interplay of supply and demand at market hubs (of which the most important are TTF and NBP) where pipeline gas plays a more important part in price formation than LNG.[62]

Figure 7 shows prices for the traditional major Asian LNG importers – Japan, Korea, and Taiwan – which have consistently been above (and mostly substantially above) $6/mmbtu over the past decade. These countries have little or no domestic gas production and therefore LNG imports set the wholesale price. Price increases in the period 2011–14 were partly due to nuclear power station closures in Japan after the Fukushima nuclear disaster, and partly to the very high oil price levels to which LNG prices are contractually linked.

Figure 7: Wholesale Gas Prices in Japan, Korea and Taiwan 2005-18



Source: IGU, Wholesale Gas Price Survey for respective years.

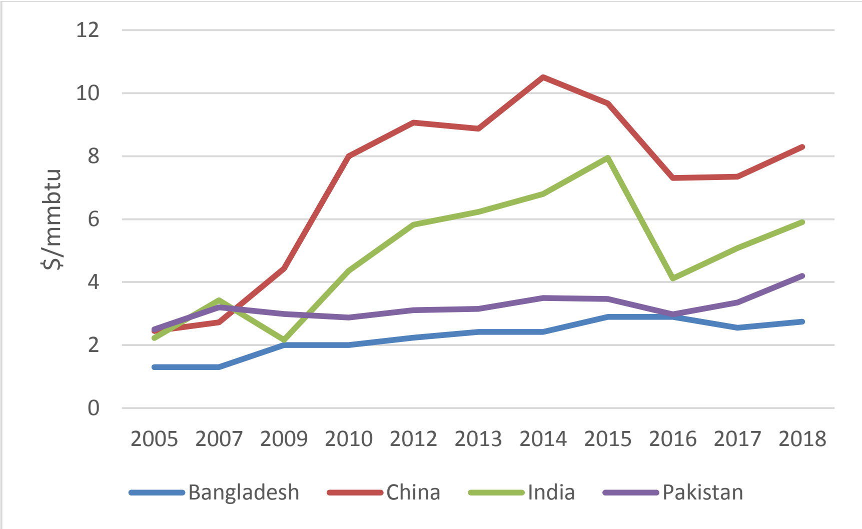
Figure 8 shows prices for four current importers of LNG in east and south Asia. Gas prices in China have been in the $8–10/mmbtu range for most of the 2010s.[63] Indian gas prices briefly rose above the $6/mmbtu threshold, then collapsed and recovered to that level in 2018. Prices in Bangladesh and Pakistan have mostly been significantly below $4/mmbtu but have increased in 2019.[64]

[62] Heather (2019) rated Spain's (PVB) an 'active hub' in 2018. There is no hub in Portugal and although the Turkish exchange EPIAS started to offer a gas contract in October 2018, initial results have been poor. Differences in prices between individual markets exist and, depending on the global LNG supply/demand balance (and hence volumes of LNG imports), the relative importance of pipeline gas and LNG may fluctuate.

[63] For contrasting affordability of gas between China and India see O'Sullivan and Sen (2018).

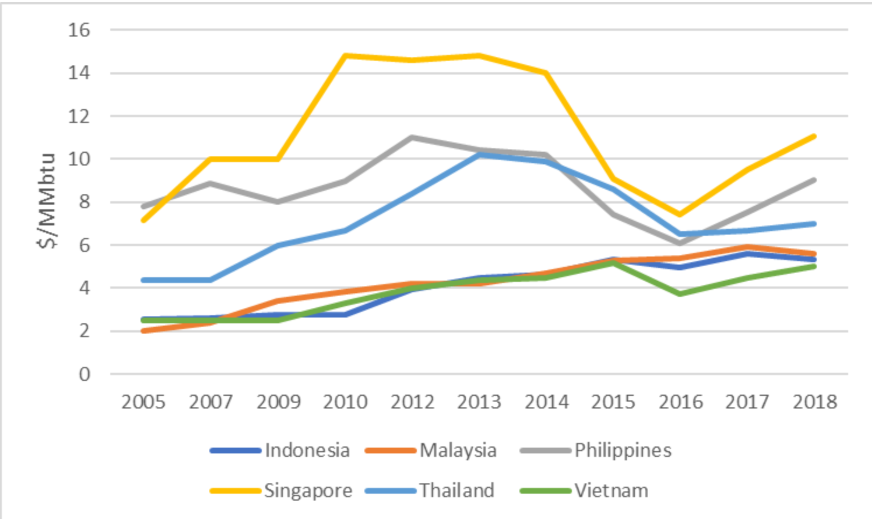
[64] The price of gas for export-oriented (but not other) industries in Pakistan was raised to $6.50/mmbtu in 2019. Bangladesh prices were raised by an average of 32 per cent in July 2019 to pay for LNG imports. While gas prices remain subsidised in both countries, there is evidence of a determination to limit the scale of the subsidy. The impact of the price increases on LNG demand is not yet clear. Evans (2019a) and Evans (2019b).

Figure 8: Wholesale Gas Prices in East and South Asia 2005-18



Source: IGU, Wholesale Gas Price Survey for respective years

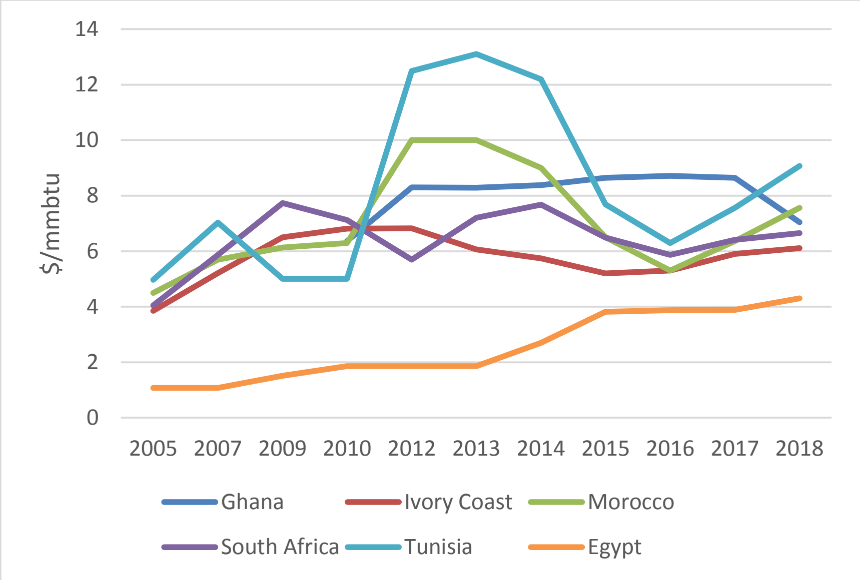
Figure 9: Wholesale Gas Prices in South East Asia 2005-18



Source: IGU, *Wholesale Gas Price Survey* for respective years.

Figure 9 shows prices in six south east Asian countries which are (or which will over the next few years be) importing LNG. Singapore, Philippines, and Thailand have had prices in excess of $6/mmbtu for the past decade. In 2016 there was considerable convergence of regional prices. Since 2016, prices have diverged but Indonesia, Vietnam, and Malaysia are coming close to a $6/mmbtu price level.

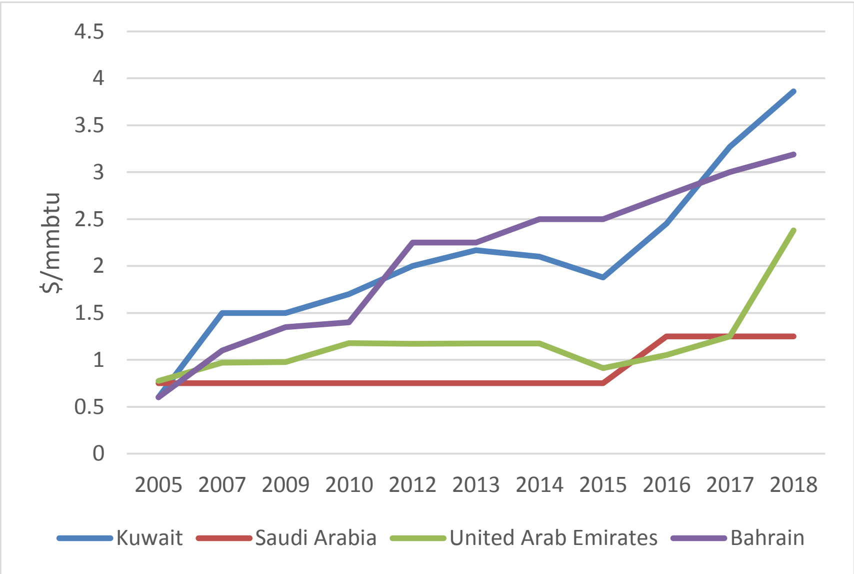
Figure 10: Wholesale Gas Prices in Africa 2005-18



Source: IGU, Wholesale Gas Price Survey for respective years.

The four African countries shown in Figure 10 which may import LNG in future have had price levels in excess of $6/mmbtu. Exceptions are Ivory Coast (which is also not yet importing) and Egypt which, after being an exporter since 2005, started to import LNG in 2015. Very substantial discoveries and a resumption of exports in 2019 suggest, however, that imports (if they continue at all) will be reduced to low levels.[65]

Figure 11: Wholesale Gas Prices in the Middle East 2005-18



Source: IGU, Wholesale Gas Price Survey for respective years.

Of the four Middle East countries in Figure 11 which already, or in the future may, import LNG, none has prices significantly in excess of $3/mmbtu. However, prices in Kuwait, Saudi Arabia, and UAE do not reflect affordability levels. These are subsidised prices which reflect a combination of the political

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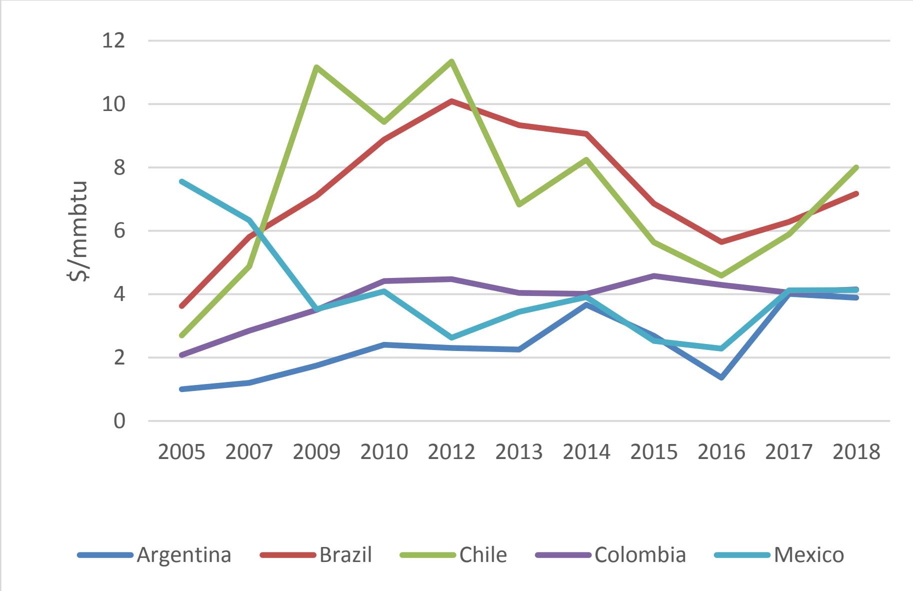
[65] Ouki (2018).

and social compact between the population and ruling elites, and industrial policy to ensure competitiveness of exports. Although the levels of subsidy are some of the highest in the world for gas, governments in these countries can, and will, continue to afford them.[66] In Bahrain, LNG imports are due to start in 2019 but affordability could be a serious problem in relation to the country's financial capacity.[67]

Figure 12: Wholesale Gas Prices in Latin America 2005-18



Source: IGU, Wholesale Gas Price Survey for respective years.

Of the five significant Latin American LNG importers in Figure 12, prices in Brazil and Chile have been substantially higher than $6/mmbtu for much of the 2010s, while Columbian prices have remained stable at a little over $4/mmbtu. Argentinian prices only recently reached $4/mmbtu but increasing production (due to shale gas development) may largely eliminate the need for future LNG imports and create the possibility of exports.[68] Mexican prices are very heavily influenced by pipeline and LNG imports from the US which accounted for 57 per cent of demand in 2018 with non-US LNG imports contributing just over 2 per cent.[69]

[66] Kuwaiti prices are misleading because although KPC charges international prices to the power company (Ministry of Electricity and Water) the losses on sales to customers are covered by the government budget. Alsayegh and Fattouh (2019). For more general observations on Gulf gas prices see Stern (2019a).
[67] Ouki (2019).
[68] Mander (2019), O'Brien (2019). Although the country may still need LNG imports in the peak winter months because of lack of storage and insufficient pipeline capacity to meet demand in the Buenos Aires market.
[69] BP (2019b), p.34, 40-41. IGU data classifies Mexico under North America but for convenience it is included here under Latin America.

Affordability and the need for subsidy

Table 1 summarises the wholesale price data in Figures 8-12 for non-OECD current and potential importing countries.

Table 1: Wholesale Gas Prices in non-OECD Current and Potential LNG Importing Countries

	Wholesale prices representative of the period 2010-18			Gas Demand 2018	LNG Imports 2018	GDP per capita US$ 2018
	HIGH	MEDIUM	LOW			
	>$8mmbtu	$6-8/mmbtu	<6/mmbtu	(bcm)	(bcm)	
China	X	X		286.0**	73.5	9771
India		X	X	58.1	30.6	2016
Pakistan			X	43.6	9.4	1473
Bangladesh			X	28.4	1.2	1698
Singapore	X			12.3	4.5	64582
Philippines	X			4.1	YTI	3013
Thailand	X	X		49.9	6.2	7274
Malaysia			X	41.3	2.5	11239
Indonesia			X	39.0	5.3***	3891
Vietnam			X	9.6	YTI	2564
Morocco	X	X			YTI	3238
Cote D'Ivoire			X		YTI	1716
South Africa		X		4.3	YTI	6340
Ghana	X	X			YTI	2202
Kuwait			X	21.8	4.3	34244
Saudi Arabia			X	112.1	YTI	23219
UAE			X	76.6	1	43001
Brazil	X	X		35.9	2.9	8921
Chile*	X	X		6.4	4.3	15923
Colombia		X		13.0	0.44	6651
Mexico			X	89.5	6.9	9698

YTI = yet to import; *Chile is an OECD member **including Hong Kong ***from domestic sources

Sources: BP (2019b), GIIGNL (2019). https://data.worldbank.org/indicator/NY.GDP.PCAP.CD

Only 10 out of the 21 countries in Table 1, have had wholesale gas prices consistently above $6/mmbtu over the past decade. Four of these have yet to import LNG and five had LNG imports of less than 10 bcm in 2018. China stands out as the country where gas demand and LNG imports are already large with the potential to increase significantly at prices exceeding $6/mmbtu. Of the others in Table 1, India is the other country with substantial gas demand and LNG imports, but uncertainties in respect of affordability, which may account for the discrepancy between projections of future regional gas demand in Figures 1 and 2. In Kuwait, Saudi Arabia, and UAE wholesale prices are not a good guide to affordability due to the ability and willingness of governments to continue substantially subsidise gas consumers.[70]

Only four of the countries in Table 1 had wholesale gas prices consistently above international pipeline and LNG price levels (Figure 13) over the past decade, suggesting that for much of the period government subsidies were necessary to support LNG imports. It is very difficult to make a definite judgement on this issue, given the possibility that high value (export-oriented) industries in these countries may be sufficiently profitable to purchase LNG without subsidy. However, it is highly unlikely that non-subsidised LNG imports would have been possible in the ten countries with wholesale prices consistently below $6/mmbtu, many of which also have GDP per capita levels below $3000/per annum. These judgements may change as GDP and wholesale price levels increase, particularly in Asian countries with a rapidly expanding middle class.[71] But there must be significant doubt that governments in these countries will be willing or able to give financial support to substantial increases in LNG imports. There may be exceptions where LNG is replacing liquid fuels in power generation (which in any case require subsidy), or where improving local air quality is a political priority. But LNG imports will be at risk in countries where lower cost alternatives (mainly coal and renewables) are available.

This overview leads to the conclusion that, although numbers of LNG importers are increasing, in terms of affordability and gas market potential the newer Asian markets hold the key to future LNG expansion, particularly if – as seems possible - the traditional large, high price LNG import markets have limited future potential post-2030.[72] China, India and a significant number of south and southeast Asian markets have substantial growth potential compared with their 2018 LNG import levels. Projections in Table 2 show Chinese LNG imports increasing from just under 70 bcm in 2018 to 132-163 bcm in 2030, and India from 30 bcm to 42-52 bcm over the same period. In eight south and south east Asian countries LNG imports are likely to increase from 24 bcm in 2018 to 108-140 bcm in 2030. But five of the latter are in the less than $6/mmbtu price category and therefore may find it challenging to increase their imports on this scale; results will depend on a combination of the capacity of their governments to subsidise, and the elasticity of demand as prices increase.[73]

[70] But there is also significant potential for, particularly, UAE and Saudi Arabia to commercialise more of their domestic gas reserves and therefore avoid the need for LNG imports. Fattouh and Shabaneh (2019) and Mills (2019).

[71] BP (2019c) p.5,19,37 and 81 places significant emphasis on the importance of middle classes in developing countries in general, and Asia in particular, in relation to increases in GDP and energy consumption.

[72] The traditional markets being Japan (where the restart of nuclear power stations may limit the need for LNG), South Korea, and Taiwan where market expansion potential may be limited despite possible phase-out of coal and nuclear power, and Europe where, as shown in Section 2, natural gas demand will need to contract significantly post-2030 if carbon reduction targets are to be met.

[73] Rogers (2019). The eight countries are: Indonesia, Malaysia, Thailand, Singapore, Vietnam, Philippines, Pakistan, and Bangladesh.

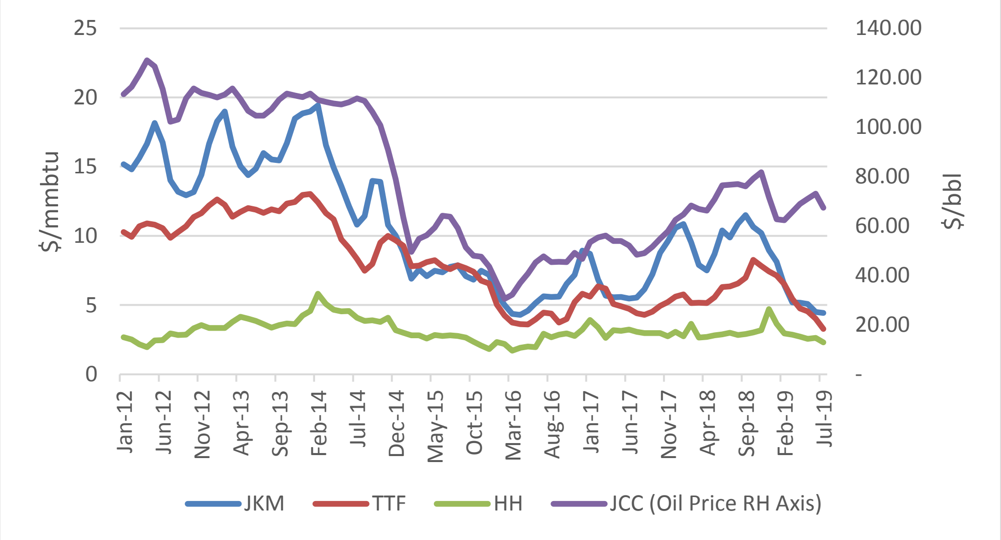
Table 2: Projected LNG Imports in 2030 (bcm)

	2018	2030	
		low	high
Japan	111	77	93.9
Korea	57.7	61	68.7
Taiwan	22.9	29	32.6
China	69.1	132.4	163.4
India	29.6	41.9	51.5
Indonesia	3.8	14.2	19.3
Malaysia	1.9	8.3	14.9
Thailand	5.6	22.5	25.9
Singapore	2.4	17.8	22.4
Pakistan	9.2	21.6	27.5
Bangladesh	0.8	13.9	16.8
Vietnam	0	8.3	10.2
Philippines	0	1.7	3

Source: Rogers (2019).

But as Figure 13 shows, for periods since 2016 – and in particular during 2019 – spot LNG prices in Asia (represented by JKM) had sunk to levels which would make LNG affordable in those markets. These spot prices were significantly below the oil-linked (JCC) levels which remain common in Asian long-term LNG contracts. Therefore, the possibility of buying spot cargos at low prices and potentially adjusting long-term contract prices closer to spot levels, by means of periodic price reviews, holds out the prospect of making LNG imports more affordable in lower price markets.[74] However, while a significantly lower price level would encourage greater demand, it could also threaten the profitability of new (and some existing) projects.

Figure 13: International Gas and LNG Prices 2012-19



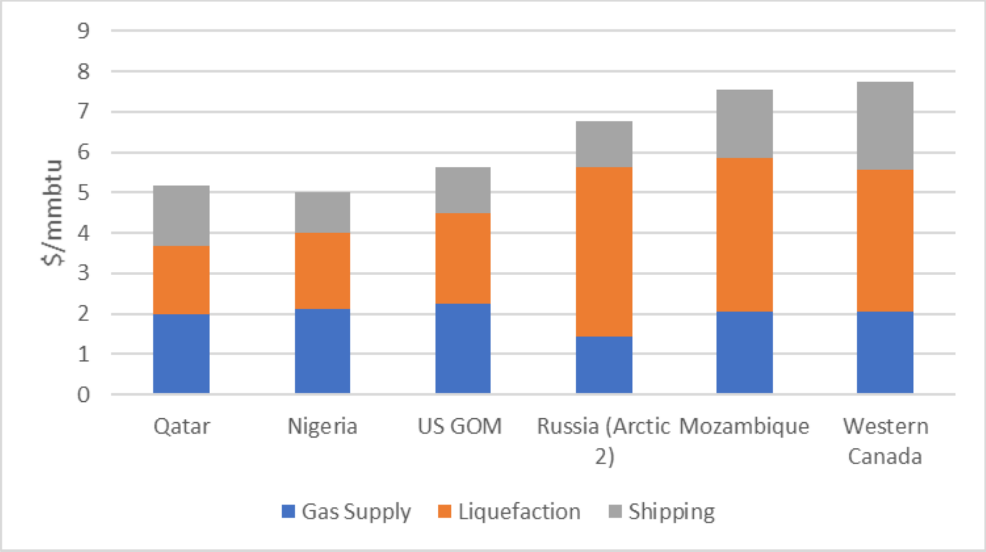
Source: Fulwood/OIES, Argus, Platts.

[74] Fulwood (2019); Ason (2019).

Cost estimates for new LNG projects

The OIES Gas Programme has published substantial research on the costs of new LNG projects and how these might be reduced in future.[75] Figures 14-16 reproduce Steuer's estimates of LNG project costs in 2025 for new projects (which have just taken or are likely soon to take FID) in six different countries for different markets.[76] Figure 14 shows cost estimates for delivering LNG from new projects to north west Europe, Figure 15 shows the same for delivery to high price Asian markets (Japan, Korea, Taiwan, and China), and Figure 16 for delivery to low price markets in India, Pakistan, and Bangladesh. The differences in costs are largely accounted for by shipping but the Nigerian, Canadian, Mozambique, and Arctic 2 projects also have differences in supply costs.

Figure 14: Cost of LNG from New Projects Delivered to North West European Markets in 2025



Source: Steuer (2019), Figure 12, p.21. (Updated using the same methodology.)

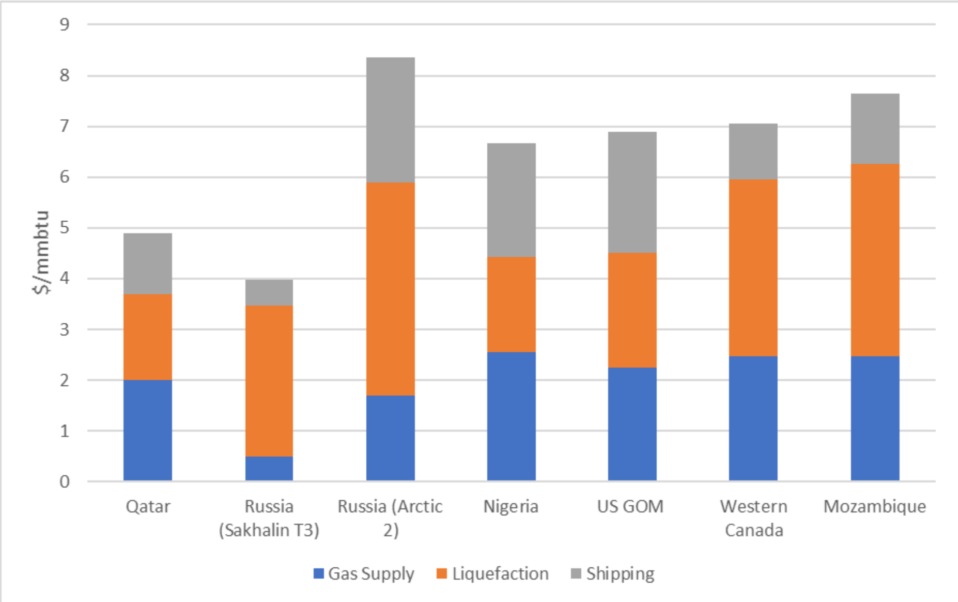
Figure 14 shows that all projects can be delivered to north west Europe at less than $8/mmbtu, although existing US and new Canadian projects are close to that level. The Arctic 2 figure is significantly higher than the operator's estimate of $4.84/mmbtu for delivery to Europe.[77]

[75] See most recently Songhurst (2018), Songhurst (2019) and Steuer (2019).

[76] Steuer's research embodies a great many methodological assumptions which are applied across the range of projects studied. His estimates may therefore differ from those announced by project developers. For the purposes of this paper Steuer updated the data from the March 2019 study and added the Arctic 2 project using the same methodology.

[77] Novatek (2017), Slides 56-57.

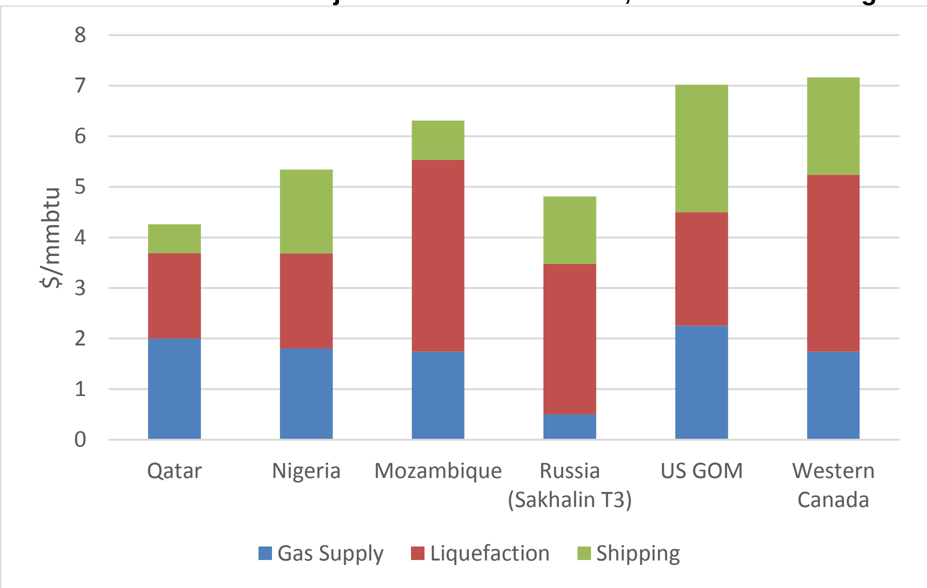
Figure 15: Cost of LNG from New Projects Delivered to Japan, Korea, Taiwan, and China in 2025



Source: Steuer (2019), Figure 13, p.21. (Updated using the same methodology.)

For high wholesale price countries in Asia (Japan, Korea, Taiwan, and China), the findings are similar to those of Europe. Steuer's estimate of Russia's Arctic 2 costs is substantially higher than that of the project developer Novatek (2017) at $5.71/mmbtu. Recouping costs for the higher cost projects may be problematic for exports to some of the south east Asian countries in Figure 9.

Figure 16: Cost of LNG from New Projects Delivered to India, Pakistan and Bangladesh in 2025



Source: Steuer (2019), Figure 15, p.22. (Updated using the same methodology.)

For low wholesale price countries (India, Pakistan, and Bangladesh) only Qatar, Nigeria, and Russia (Sakhalin) are below the $6/mmbtu cost level suggesting that prices may need to increase to around $7/mmbtu or above, if others are to achieve profitable sales.

It needs to be stressed that these are cost estimates for *new* projects. They are in many cases significantly below the costs of projects which started production in the 2010s particularly for Australian projects which ranged from $8-15/mmbtu.[78]

6. Summary and Conclusions

The propositions underpinning this paper are that the global LNG industry, despite a huge expansion of capacity with final investment decisions on projects potentially in excess of 100 bcm in 2019 and 2020, faces affordability and decarbonisation challenges for the following reasons:

- For lower wholesale price gas markets, LNG prices significantly above $6/mmbtu may be problematic, and prices above $8/mmbtu may rule out any significant expansion of imports in these markets;
- By the late 2020s limits could be placed on sales of unabated LNG in carbon-sensitive countries;
- A combination of these two issues could lead to profitability problems for both existing and new projects.

Affordability and profitability

In relation to affordability, LNG prospects look much better than they did three years ago. Cost estimates for most new projects suggest that they will be able to deliver profitably to most established and anticipated LNG import markets at or below the wholesale prices prevailing in those markets over the past decade, particularly in China and south east Asia which are projected to have the largest increases in imports up to 2030. There may be problems for some new projects to profitably supply India, Pakistan, and Bangladesh without a sustained increase in wholesale prices or increased government subsidies in those countries. Spot prices well below $6/mmbtu in 2019 – should they extend into 2020 and beyond – could provide a useful indicator of price elasticity of demand in these markets, but will also severely impact the profitability of some existing higher cost projects. New LNG projects need to factor in costs related to future decarbonisation requirements in both exporting and importing countries and when these requirements might be imposed.

Decarbonisation

Natural gas is a fossil fuel which contributes to greenhouse gas emissions. The natural gas combusted along the LNG value chain (principally that needed to liquefy natural gas at minus 162 C) equates to 11-13 per cent of the gas produced at the wellhead, which means that LNG has significantly higher emissions than a typical pipeline gas value chain. Decarbonisation, in the context of emission reductions, has yet to be addressed by most LNG projects, although two liquefaction projects in Norway and Australia have carbon capture and storage, and new Canadian projects are subject to tight emission controls.

In order to meet COP21 targets, unabated gas demand in Europe will need to decline in the 2030s (at the latest), while in other regions decline may be delayed until the 2040s. This means that projects taking FID in 2019-20, and starting operations around 2024-25, may not have recovered their costs prior to anticipated European demand decline, but should have done so prior to more general global decline. Nevertheless, tightening emissions standards should be very much on the radar of new project developers.

The LNG community needs to replace an 'advocacy' message, based on the generality of emissions from the combustion of natural gas being lower than other fossil fuels, with data on carbon and methane emission data from specific value chains, calculated using transparent methodologies. Methodologies and data may take several years to establish for the different elements of the LNG

[78] Songhurst (2018), Appendix 1, p.33.

value chain in individual countries. But cargos which do not have value chain certification by accredited authorities, or which fail to meet defined emission standards, run the risk of progressively being deemed to have a lower commercial value (because they will require buyers to purchase emission offsets of various types), and eventually being excluded from jurisdictions with the strictest standards.

GHG (carbon+methane) emissions data from LNG value chains – the sum of the individual elements: exploration and production, transmission, liquefaction, shipping, and regasification - and methodologies of calculation, need to be transparent, available and certified by accredited (national or international) companies or regulatory institutions. There will be no place in this process for confidentiality; nothing less than complete transparency will be acceptable. This will be the only way to achieve credibility and counter allegations that high methane emissions mean that (natural gas and) LNG projects, are 'worse than (or no better than) coal' in relation to GHG emissions.

Having established certified emissions, the next step will be for projects to take, as soon as possible, combinations of the following measures:

- offset their emissions by means of renewable energy or forest investments;
- progressively replace natural gas by low or zero carbon gas (biogas/biomethane in the liquefaction feedstock, or…
- decarbonise the regasified LNG to produce hydrogen (by means of steam- or auto-thermal reforming) which would require development of carbon capture utilisation and storage (CCUS) in either the exporting or importing country...
- requiring further consideration of hydrogen export and import options.

These measures will probably be country-, project- and value chain element-specific. Governments in some exporting countries have already mandated emission levels from liquefaction plants and CCS from upstream production. Importing country governments which have adopted stringent carbon reduction targets can be expected to impose emission standards in respect of all fossil fuels over the next decade, particularly if it becomes increasingly evident that they are failing to meet these targets. To the extent that LNG suppliers can meet standards through offsets such as forest projects or low cost biogas and biomethane, this may not greatly impact their business. However, any requirement to transform regasified methane into hydrogen with CCS would substantially impact project economics, and the affordability of LNG relative to other energy choices.

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