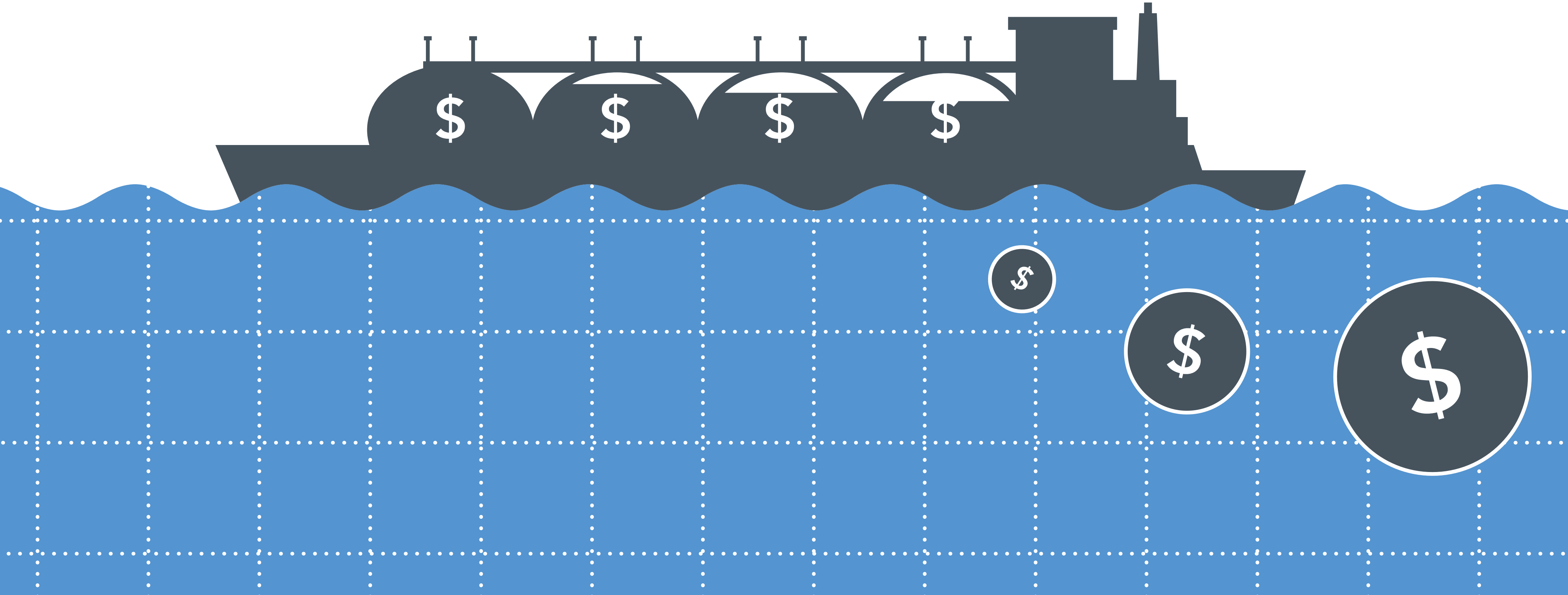
Carbon Tracker Initiative

Carbon supply cost curves:
Evaluating financial risk to gas capital expenditures



About Carbon Tracker

The Carbon Tracker Initiative (CTI) is a financial not for profit financial think-tank. Its goal is to align the capital markets with the risks of climate change. Since its inception in 2009 Carbon Tracker has played a pioneering role in popularising the concepts of the carbon bubble, unburnable carbon and stranded assets. These concepts have entered the financial lexicon and are being taken increasingly seriously by a range of financial institutions including investment banks, ratings agencies, pension funds and asset managers.

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More detailed papers on gas supply and demand are available at:
www.carbontracker.org/report/gascostcurve

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The underlying analysis in this report prepared by Carbon Tracker and ETA is based on supply cost data licensed from Wood Mackenzie Limited. Wood Mackenzie is a global leader in commercial intelligence for the energy, metals and mining industries. They provide objective analysis on assets, companies and markets, giving clients the insights the need to make better strategic decisions. The analysis presented and the opinions expressed in this report are solely those of Carbon Tracker & ETA.

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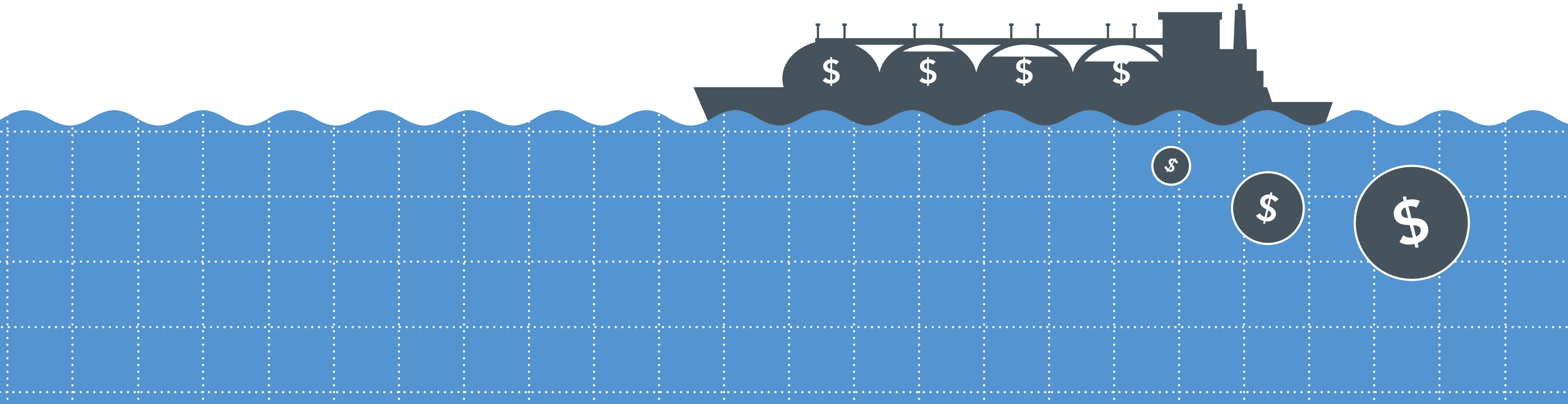


Executive summary

Perfect storm

2015 has only confirmed the direction of travel away from fossil fuels. The G7 has agreed to aim to reduce emissions by up to 70% below 2010 levels by 2050. Efforts to keep global warming below 2 degrees are ratcheting up, which is tightening the carbon budget remaining for fossil fuels. There are many combinations of coal, oil and gas which could make up the future fossil fuel portion of the world's energy supply. This will vary across power, heat and transport uses, and between regions. This direction of travel to a low carbon future is not just about getting a global deal on climate change. Even as the negotiations have continued, there has been a perfect storm of factors at work. These include concerns over health and air quality, technological advances like domestic energy storage products, the decoupling of economic growth and energy demand, and the continued fall in the cost of renewables.

Demand and price

Analysing the world's gas supply brings you very quickly back to demand. Until LNG became commercially viable, many gas deposits were literally stranded, as they had no access to potential markets. The advent of LNG technology has connected supply and demand bringing gas to new countries, and competition to existing markets. The need for capital intensive infrastructure means that new LNG supply is unlikely to progress far without the gas being contracted in advance. This doesn't mean you can't have too much gas though – if utilities overestimate the demand for their gas power generation, oversupply can weaken prices. The drop in oil prices over the last year has also put pressure on contract prices linked to the oil benchmarks.

Gas connoisseurs

Low carbon scenarios do include the potential for gas demand to grow over the next decade. But if we are to stay within a carbon budget the world needs to be selective in developing gas supply, in order to ensure we use the remaining budget most efficiently. This will also be driven by the relative costs of different power sources in each region. The golden age of gas once mooted by energy commentators has not arrived in most regions. With the costs of renewables falling, gas is already struggling to compete in some markets, or could be priced out soon in others. The shale gas revolution in the US has been the exception, but this has not been replicated in Europe where the swing has been from coal to renewables.

Fugitives on the run

The issue of fugitive emissions has raised questions over the climate benefits of unconventional gas. There is no consensus on the extent of the problem, but there is agreement action is needed. The development of shale gas has prompted proposals from regulators and industry in North America. These need to be delivered fast if gas is to demonstrate it can help meet carbon pollution targets. At the gas prices in our scenarios, capturing this lost product should more than pay for itself, so there is little excuse for not dealing with the problem. The solutions need to be applied to all gas and coal developments and infrastructure, including conventional gas, as there is no room in the carbon budgets for fugitive emissions exacerbating the situation.

LNG left on the shelf?

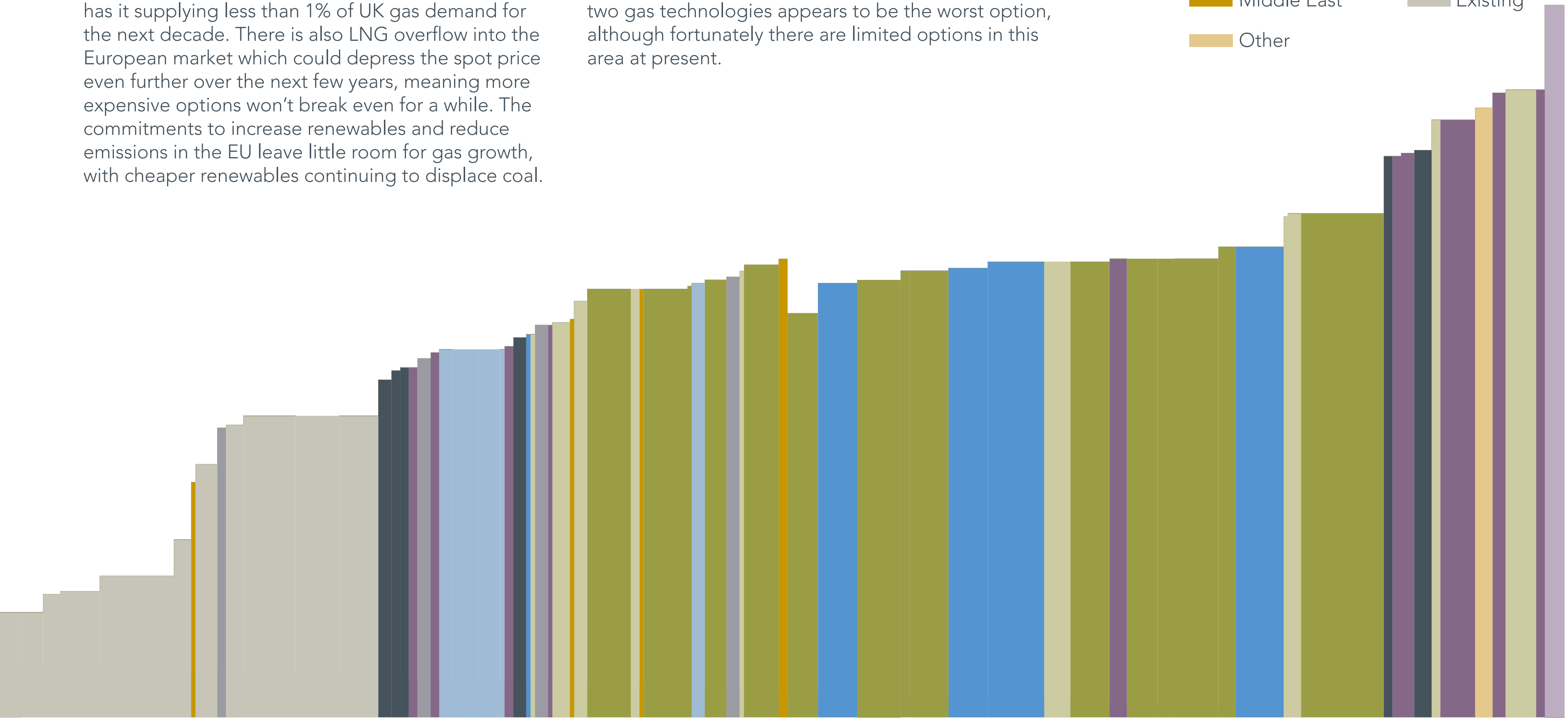
Partly due to the long lead time, LNG supply is covered for a low demand scenario for the next decade. Beyond this LNG with supply costs below around $10/mmBtu delivered to Japan will be needed. But there are $283bn of high cost, energy intensive LNG projects that would continue to be deferred if demand disappoints. In particular the number of LNG plants in the US, Canada and Australia could disappoint those expecting large LNG industries to develop.

European diversity

Europe has a range of gas supply options – and as a result may not need them all in the next couple of decades. The existing pipeline infrastructure determines much of the trade, with Russian gas on tap. The volume and price supplied by Russia will impact the marginal gas options for remainder of the market. Again the breakeven threshold for a low demand scenario is around $10mm/Btu. Even if piped gas or LNG doesn't displace UK shale gas, the model has it supplying less than 1% of UK gas demand for the next decade. There is also LNG overflow into the European market which could depress the spot price even further over the next few years, meaning more expensive options won't break even for a while. The commitments to increase renewables and reduce emissions in the EU leave little room for gas growth, with cheaper renewables continuing to displace coal.

High carbon high cost

A consistent theme to our cost curve analysis has been to identify the high carbon, high cost options which aren't consistent with a reasonable carbon budget. Gas is a mixed bag which prompts a wide range of responses, which touch on issues beyond debating its climate benefits to energy security and water pollution. Sticking to our financial and climate perspectives, the biggest question marks arise over unconventionals and LNG. The combination of these two gas technologies appears to be the worst option, although fortunately there are limited options in this area at present.



Foreword

Carbon Tracker's financial research has created a new debate around climate change and investment literally reframing the debate – "the climate swerve".

Carbon Tracker started this journey by considering the stocks of carbon in coal, oil and gas in the ground and comparing them to the carbon budget necessary to keep average global temperature increase below 2°C thereby achieving a high probability of avoiding, what the international community considers to be dangerous levels of warming.

This gas analysis completes the series of carbon supply cost curve reports looking in turn at oil, coal and now gas. Carbon Tracker's focus is translating a key aspect of the climate science, the carbon budget, into the language of our audience, the financial markets in a way that tells them they have a financial risk issue now.

This report is, so far as we are aware, the first time anyone has sought to look at key gas markets in both a holistic and granular way. So in that sense alone it is a unique and important milestone. As a reference scenario we have assumed that gas would have a 24% share of a global carbon budget. This does of course raise interesting questions around other scenarios, where oil or coal might have a smaller share of the budget. This report clearly demonstrates that global gas industry presents a much more complicated picture then either oil or coal. It is a mixed bag. For the gas industry there is some good news as unlike oil and coal there is still some limited room for growth even within the 2°C budget. Unfortunately for the industry this is not anywhere near as much as it projects and certainly does not suggest a golden age of gas.

Major players in the gas industry are taking positive steps to quantify and address the fugitive emissions issue. If they are successful in achieving the commitment to limit fugitive emissions at 1% across the industry this will go a long way to positioning gas as a carbon 'lite' option. But they are not there yet and more companies and regions need to come onboard to ensure there is clear blue sky between unconventional gas and coal.

Alongside policy measures we are seeing the potential for disruptive advances in energy technology that can outcompete centralised power generation whether from coal or gas and provide cheap access to renewable energy for all. This is even more pronounced for gas in emerging markets without indigenous gas supply, where expensive infrastructure is needed for any coal to gas switch. With the cost of renewables falling all the time, time is running out for gas in some markets.

There is a realisation that ignoring climate risk and hoping it will go away is no longer an acceptable risk management strategy for investment institutions. Pension funds are under increasing pressure to articulate how they are addressing the need to both mitigate emissions and adapt to changing climates and markets. Since our coal report in September 2014 many investors now see coal as not only the most visible target of all, and so most at risk of regulatory intervention, but as a poor investment. Gas by contrast is still seen as the clean alternative by many investors. This report shows that the reality is a much more complex and nuanced picture, if it is assumed there is not unlimited demand for gas.

Carbon Tracker is not an advocate of a pure divestment approach to fossil fuels. Rather we advocate engagement, correctly pricing the risk premium associated with fossil fuels, transparency and the closure of high cost, high carbon projects – project level divestment. We look to identify the most economically rational path for the fossil fuel industry to fit within the carbon budget. This is clear cut with oil where many high cost high carbon projects do not make financial sense such as arctic, oil sands and ultra deep sea projects; or coal given that much of the US coal mining industry has already shrunk in value, many investors will have limited exposure already. See our report, 'The US Coal Crash – Evidence for Structural Change', which provides strong evidence for the structural decline of coal.

The story for gas is more complicated, very much a mixed bag. This does not need to be a negative issue for investors or diversified resource companies. As active stewards of capital they can, using tools such as the carbon supply cost curve, ensure that value is maximised, either through redeployment of capital within companies, or by returning the capital to shareholders. There is clear alignment between high cost and excess carbon through the cost curve. This analysis serves as a reminder to investors to ensure company strategy is aligned with their best long-term interests.

Anthony Hobley

CEO, The Carbon Tracker Initiative
July 2015

1. Introduction

Competition between fossil fuels

Having produced global cost curve analyses for oil and coal in 2014, this set of gas cost curves completes the set of fossil fuels. It comes at a timely moment with fierce competition between coal and gas as a power source going forward. This is encapsulated in the renewed calls by the European oil and gas sector for measures such as a global carbon price, which will favour its gas production over coal for large power plants.

Climate benefits

Gas is often billed as a cleaner fossil fuel compared to coal, but this is not guaranteed (New Climate Economy 2015). As with all greenhouse gas accounting the devil is in the detail. The potential for extra methane emissions from unconventional gas and the energy requirements of producing liquefied natural gas (LNG) need to be addressed. There is growing industry and investor attention on these matters, as research continues to improve understanding and reduce emissions.

Complex regional markets

The gas analysis is undoubtedly the most complex of the three fuels, with competing supplies and the global trade in LNG to analyse. There is significant regionality, as exemplified by the growth of US shale gas production, the uncertainty around EU carbon markets, and Asian LNG demand projections.

New trading dynamics

The interaction between these markets is also critical. The majority of the LNG market is contracted in advance to justify the huge capital investment. Some flexible production is retained for sales on the spot markets. This has created a new dynamic with LNG oversupply offering some diversification from Russian piped gas in Europe. North American LNG exports are a new option being considered, with the potential to take spot prices linked to Henry Hub, rather than being linked to oil prices as is the case in much of the rest of the market.

Golden age or gold rush?

The talk of a golden age of gas has been around for a while. This has seen huge investment pour into new gas supplies. As with any commodity there is a risk that this leads to cost inflation, oversupply, and weakening prices. Growth in demand for gas is expected in most scenarios – the question is how much? The current glut of LNG supply demonstrates that the gas value chain is still capable of misreading future demand levels. The initial rush for US shale is now over, with questions being raised about its financial stability in a low oil price environment.

Operating within a carbon budget

Creating an energy system that fits within a carbon budget still imposes limits on all fossil fuels, including gas. This means that in low carbon scenarios less gas will be required over the next few decades than in business as usual, where consumption grows at a faster rate. Some scenarios may have faster growth of gas use earlier on, but this would displace the available carbon budget elsewhere. This could be reducing the share of coal or oil, or lowering unmitigated combustion of gas later on.

Paris and beyond

The UNFCCC COP in Paris at the end of 2015 is only the next step in the global negotiations. It will confirm the current country level objectives which can be further ratcheted down. Alongside this are the announcements from the G7 to aim for up to 70% decarbonisation by 2050, and the raft of regional, city, corporate and investor commitments to reduce emissions and increase renewables. These all represent a downside for fossil fuels at the high end of the cost curves.

Further investment

There will undoubtedly be more investment in developing gas supplies. However there will be a limit to how much is needed, especially given how much capital has already piled into new LNG supply for example. This study aims to inform how much investment may be required in a low carbon scenario.

2. Allocating the carbon budget

Continuing from our previous carbon supply cost curves analyses of coal, and oil, the remaining carbon dioxide budget for gas in the reference scenario is 216 $GtCO_2$ (with 324 $GtCO_2$ for coal and 360 $GtCO_2$ for oil). This allocation is based on the proportions of emissions from coal, oil and gas projected in the International Energy Agency's (IEA) 450 scenario. It represents 24% of the total budget to 2050 of 900 $GtCO_2$ which is estimated by the Grantham Research Institute on Climate Change at LSE to give an 80% probability of limiting anthropogenic warming to 2°C.

Based on the distribution of emissions through the decades, just over 50% of the carbon budget for gas is apportioned up to 2035. The analysis only runs to 2035 to match the availability of the gas supply and economics data. This provides a carbon budget of around 125 $GtCO_2$ for this period. This is apportioned as follows:

Figure 1: Breakdown of gas carbon budget

	$GtCO_2$ emissions to 2035	
Gas Type	450 scenario	LDS
Conventional	77.5	82.0
LNG	16.8	16.9
Unconventional	30.9	33.3
Total	125.2	132.2

Gas consumption before delivery

The gas supply data displayed in this analysis is the volume delivered under contract to the customer. We have therefore had to factor in the consumption of gas in the extraction phase (6%) for all gas. For LNG there is further usage of gas prior to delivery in the liquefaction and regasification processes (12%), as well as in boil-off during ship transfer (2.5%). These percentages are based on analysis of 2012 IEA demand data compared to the 'marketed' data analysed in the model.

Fugitive methane emissions

The carbon budgets used in our analysis refer only to carbon dioxide emissions. There is an inherent assumption regarding efforts to tackle other greenhouse gases in modelling these carbon dioxide budgets. These budgets do not factor in any significant uplift in methane emissions due to the growth in unconventional gas.

Both conventional and unconventional gas operations have fugitive emissions. For each 1% of leakage, the leaked methane amounts to around 12% of the CO_2 emissions from the combustion of the remaining gas, on a CO_2-equivalent (CO_2e) basis (WRI, 2015). Using WRI and IEA analysis as a guide, gas needs fugitive emissions of less than 3% to provide a climate benefit over a typical coal plant (noting there is variation in performance at a plant level for both coal and gas) (WRI 2013, IEA 2012).

Both industry and government bodies are developing a number of initiatives to tackle fugitive emissions (CCAC Oil & Gas Methane Partnership; One Future US). This is still an emerging area of research, with a wide range of results. We surveyed a number of recent studies which had fugitive emissions levels ranging from 0.42% to a 10% midpoint, giving a median of 2.9% fugitive emissions for unconventional gas. This compares to median of 1.4% for studies analysing fugitive emissions from conventional gas.

Only time will tell if the unconventional gas industry can deliver significant reductions in fugitive emissions across the board. If a higher percentage of fugitive methane emissions for unconventional gas needs to be factored in, it would further squeeze the carbon dioxide budget. Further information on fugitive emissions is available in the accompanying detailed supply methodology paper.

Geographic split

We have broken down gas demand into three main markets which drive supply for producing cost curves. These are North America, Europe and LNG, which together represent around half of the global market. These markets are not entirely independent, as for example, oversupply of LNG may impact the indigenous demand levels in Europe depending on relative prices, and the competitiveness of North American LNG exports will be influenced by the domestic gas price. Much of gas supply in the rest of the world is produced and consumed domestically rather than being traded on a fully functioning market, so there is less value in showing this on a cost curve.

3. Demand scenarios

Of the fossil fuels, only gas demand is higher in 2040 compared to 2012 under IEA New Policies Scenario (NPS) and 450 scenarios, (IEA 2014). The NPS and 450 show an overall CAGR of 1.6% and 0.7%, respectively, from 2012 to 2040. The biggest contrast between the NPS and 450 scenarios – and the biggest enabler of lower fossil fuel demand – is a decrease in overall energy demand, because of energy efficiency and conservation.

The level of gas demand has grown 22% less in 450 than NPS by 2040. Within this decline, the majority of the reduction occurs between 2030 and 2040, as government policies aimed at curbing energy consumption reduce demand for all fuels. The power sector currently accounts for around 40% of gas demand, with industry and heat each making up around 20%. There is hardly any increase in gas demand for power from 2012 in the 450 scenario. There is still growth in heat and industry usage, although it is tempered by efficiency gains compared to the NPS.

The OECD remains the largest absolute source of gas demand by 2040. However, over 40% of demand growth between 2012 and 2040 comes from non-OECD Asia. In addition, the Middle East, Africa and Latin America represent one-third of total growth between 2012 and 2040. OECD demand declines by 13% by 2040 in the 450 scenario, whereas non-OECD demand increases by 49% in the same period. The regional variation in demand in IEA scenarios is reflected in how we have projected demand for the EU, North America and LNG in our analysis. More information on demand scenarios and potential drivers for change is available in the separate more detailed demand paper.

Industry outlooks

The scenarios provided by the oil majors have CAGRs between the IEA NPS and CPS of 1.6% or higher to 2035. The percentage change is shown as the different scenarios are not directly comparable. The Low Demand Scenario (LDS) presented here is essentially an updated NPS which has a global CAGR of 1.4%, to reflect the direction of travel we already see below the NPS.

There is very limited potential for difference in gas demand early on, due to the amount of supply already contracted in the model. Within the markets covered, the biggest difference to industry forecasts is probably a lower level of production long term (post 2020) in North America.

Direction of travel

The reasons for Carbon Tracker already seeing fossil fuel power demand lower than IEA NPS include:

- The slowing of economic growth rates, and the decoupling of GDP growth and power demand in major economies
- The restructuring of energy markets, reducing dependence on base load, and increasing off-grid generation
- Onshore wind already cheaper than fossil fuels in some markets with solar set to follow in a growing number of major markets
- The potential for disruptive new technology advancements, e.g. energy storage
- Improved efficiency of use for heating buildings

These factors create a perfect storm whereby rapid changes in the energy system can emerge. It is important to note that these areas are not dependent on a global deal on climate change – many are already happening as the negotiations continue (BNEF 2015).

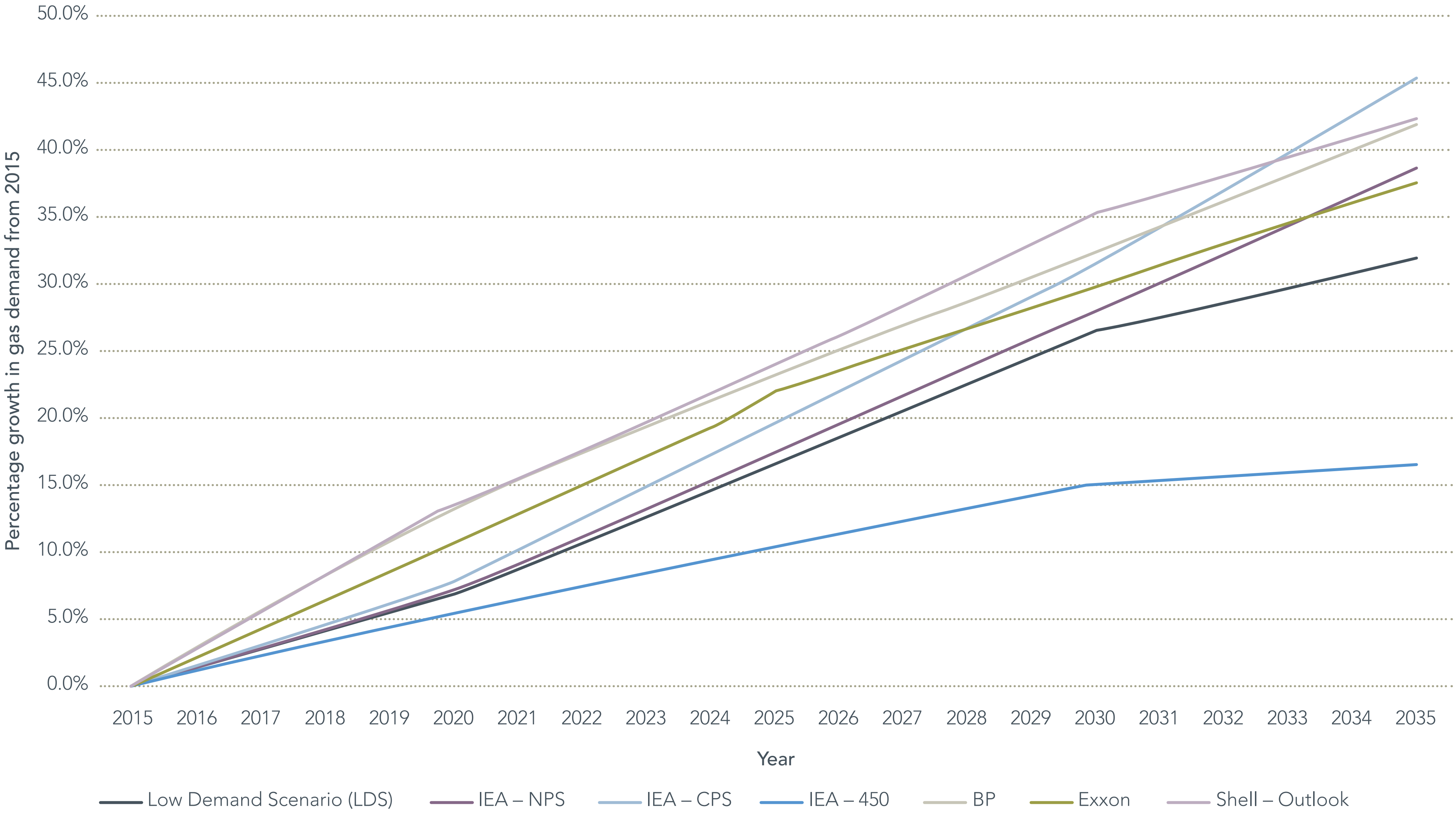
Coal to gas switching

It has long been expected that carbon pricing mechanisms such as the EU Emissions Trading Scheme would prompt a switch from coal to gas. In order for such market mechanisms to deliver this kind of change the right balance between carbon prices and commodity prices needs to result. Carbon pricing still increases costs of gas plants, however, and this also enhances the competitiveness of renewables. Over the last decade there has been no significant increase in EU gas consumption as some may have anticipated.

In the US, the swing away from coal generation has been split two-thirds gas and one-third renewables (Carbon Tracker 2015). This has been achieved through both cheap gas prices, and increasing costs for coal plants resulting from EPA measures to reduce pollution. There has already been an 8% increase in the share of gas power generation.

Thermal coal is already in structural decline in a number of markets, and official figures indicate a peak in demand in 2014 in China. The window for switching to gas may be closing however. Gas can bring some incremental benefits in terms of greenhouse emissions, but there is a limit to how many more decades of unmitigated emissions from new gas plants we can be locked into. Some regions are already leapfrogging straight to renewables as costs become competitive.

Figure 2: Comparison of demand scenarios



Sources: Company reports, IEA World Energy Outlook, Carbon Tracker analysis

450 vs low demand scenario

The analysis did model the IEA 450 scenario well as a low demand scenario closer to the IEA NPS scenario. The gap between the scenarios varies across the markets analysed for the following reasons:

- Variability of changes in demand to 2035 in the IEA scenarios across regions
- The way the model allocates LNG supply demand across an increasing number of regions
- The relative prices assumptions of the model outputs across the regions

Looking out to 2025, the differences are smaller – with the most change experienced in the decade to 2035. This reflects the more similar demand trajectories between the LDS and 450 scenarios in the short term, and the fact that most LNG supply is already contracted to 2025.

Overall production is down 5% in the 450 scenario vs the LDS over the period for the regions covered here. There is very little difference in the LNG picture between 450 and LDS.

In Europe there is a 6% reduction in demand to 2035 in the 450 scenario compared to the LDS. North America has the biggest difference with a 7% drop in production over the period to 2035.

We have displayed indicative 450 demand intersects on the cost curves for information, although the precise order of supply points along the cost curve may be slightly different in the model due to its dynamic nature, and the different regional balance between the two scenarios.

Overall capex is down 6% between the scenarios with the 450 needing $172bn less than the LDS. Half of this reduction relates to the US, with 30% relating to Europe and 20% LNG.

Price trends

Gas prices have seen increasing divergence over the last decade. Recent price trends reflect some key developments and events. In North America, the continuing development of shale gas technology has kept prices at lower levels. In Asian LNG, the Fukushima incident in 2011 stimulated elevated prices.

The picture is changing again in 2015. The recent oil price drop in the second half of 2014 has fed through into contracted gas prices which are indexed to oil prices. The oversupply of LNG is also depressing Asian LNG spot prices, which have just converged with European benchmarks, and are below the contract import prices.

Price risk

It is important to distinguish between contract prices and spot prices. The majority of LNG in Asia and Europe is supplied under contracts which are are indexed to oil prices. This has given stable high prices over the last few years; but the drop in oil prices has fed through over the last year. LNG producers may retain a proportion of production (say 10–20%) for the spot market to give flexibility to exploit higher prices. New LNG projects in North America are different in that the pricing structure is related to fixed costs plus Henry Hub.

Where gas is supplied by pipe this is also typically contracted (e.g. from Russia). The cost of new infrastructure needs to be factored into the development of fields requiring new pipeline capacity. Gas production such as that in the North Sea or from US shale is sold using spot prices or spot futures prices. Both gas suppliers and major consumers can choose to hedge gas prices to limit impacts of price movements on either revenues or costs.

If there is a period of lower gas prices for LNG and Europe over the next few years this could stimulate further investment in gas power generation and increase the proportion of gas generation capacity.

Figure 3: Comparison of gas production and capex in the regions and scenarios (2015–2035)

	Production (bcm)				Capex ($bn)			
	450		LDS		450		LDS	
	Needed	Unneeded	Needed	Unneeded	Needed	Unneeded	Needed	Unneeded
Global LNG	10,274	3,534	10,430	3,446	553	414	588	379
North America	19,910	4,513	21,358	3,064	1,063	284	1,148	199
Europe	8,279	1,172	8,829	1,018	964	347	1,015	296
Total	38,463	9,220	40,617	7,528	2,580	1,046	2,751	874

Figure 4: Trends in contract and spot gas prices across regional markets over the last decade

Source: Bloomberg data

4. Supply cost curves

The approach of using a cost curve provides an indication of the relative costs of supplying volumes of product. The basic economic theory is that the market will select the cheapest production to meet the demand level, all other things being equal. In reality other factors such as political risk, public sentiment on unconventional gas, and market regulation may override the pure economic logic, and operators will also be working to try and reduce the costs of projects where possible.

The model incorporates the geography (location of supply and demand centres) and infrastructure of global gas trade. The 'earliest start date' and breakeven cost of a project or supply source that is made available in the model is determined by Wood Mackenzie analysts to reflect project development status and its global context. As a result there are a small number of projects not needed in a demand scenario which appear cheaper on the cost curve than those that are included. For example in North America this reflects that some nodes of production will be supplying localised markets, rather than competing on a national basis.

Supply and demand

The cost curves indicate which projects are needed to meet the demand level specified – those to the left of the demand line. Beyond this potential production which is not needed in this demand scenario is to the right of the demand line. Fully unconstrained supply data was not available, especially for North America – this relates to the demand-led nature of the industry. In theory supply should be tailored to demand, however the lagtime of 5 years or more to deliver LNG infrastructure allows some mismatch to occur, resulting in periods of oversupply.

The capital-intensive nature of LNG means that most operators will secure contracts to sell the gas before they invest the capital. There will still be some price risk for the producer, depending on how the contract is structured (e.g. linked to the oil price).

Project types

For LNG and Europe the data indicates the project stage so we can identify existing projects which have already started construction or production. Beyond this we can also differentiate between conventional and unconventional projects. This enables the reader to differentiate between the different types of extraction techniques, project economics, and environmental aspects of the two types of gas.

The majority of unconventional production to date has taken place in the United States. Some other countries are seeking to apply hydraulic fracturing technology (e.g. UK, China), whilst others have banned its use (e.g. France, Germany, Netherlands). The model reflects some of these restrictions in adjusting the 'earliest start dates'. Beyond shale gas, other types of unconventional gas include coal bed methane and tight gas.

Capex and production

The three demand markets covered in this paper are the largest and most liquid globally, and represent around half of the global gas demand. Much of the rest of the world has domestic gas production which does not currently interact with the traded gas markets. As with our oil and coal studies, we concentrate on capex over the next decade (2015–2025) and production over the longer term (in this case 2015–2035).

Breakeven prices

A project's Break Even Gas Price (BEGP) is the price that – considering all future cash flows (i.e. costs, revenues, government take) – is needed to deliver an asset-level net present value (NPV) of zero assuming a given discount rate (15% for upstream (ex-US/Canada), 10% for North America upstream, 12% for integrated LNG projects, 10% for stand-alone LNG plants).

Where infrastructure has already been built, cash costs are used in place of breakeven costs to reflect the sunk nature of this capital and the move to operational economics. The boom in investment in gas infrastructure over the last few years means that there is significant capacity due to come onstream which has already invested the upfront capital, and contracted to supply gas.

Delivered cost basis

The gas costs displayed on the cost curves are the delivered costs, including transport by pipeline or LNG tanker as appropriate. This indicates the likely costs to the potential buyer.

In Europe and North America, gas transport costs are calculated based on the "most likely point of delivery" (as determined by the model), taking into account geographic and logistical constraints. In our global LNG market analysis, cargoes are indexed to Japan delivery (as a proxy for Asia generally, which accounts for the large majority of global LNG demand).

The model assumes a Brent oil price of $85 for oil indexed contract prices and when calculating the cost of gas production. Real prices are used subject to inflation of 2% post 2015 and foreign exchange rates are set as at the time of the model run.

5. LNG carbon supply cost curve

97% of the LNG required in our low demand scenario to 2025 can be met by projects already committed to. This partly reflects the long lead times for capital intensive LNG projects. New (pre-final investment decision) supply is only needed from 2024 onwards, and due to the large number of competing projects only the most cost effective likely go ahead, notably:

- Brownfield projects in the Pacific
- A limited amount of US projects
- Mozambique – supported by economies of scale and proximity to demand (India)
- Other more speculative, but likely to be competitive projects – Iran, Iraq and West Africa

Even looking out to 2035, 82% of LNG requirements for the low demand scenario already have supply identified. The marginal tranche of supply between the 450 and LDS scenario is likely to be a US LNG project.

Strategy rethink

Some companies are betting on big growth in LNG capacity. However this is based on energy demand growth, and gas' share of this larger pie. If new supply is not needed for another decade, this could leave companies seeing much lower levels of activity for the next few years. There is a further $283bn of new LNG projects over the next decade that would not go ahead if LNG capex matches our demand scenario.

Lowering expectations

It is clear that the US, Canada and Australia would have to temper their ambitions for new LNG over the next decade in a low demand scenario, with the distribution of unneeded capital expenditure as follows:

- $82bn in Canada
- $71bn in the US
- $68bn in Australia

Price assumptions

LNG pricing remains weak compared to post-Fukushima / pre-oil price crash levels in the scenario, with spot prices in the range $8–11/mmBtu for most of the period. This translates to a long term breakeven test of around $10/mmBtu. The model selects which projects go ahead based on spot prices for LNG. It is important to note that LNG projects can require 15–20 years to pay back the capital costs, so long-term pricing is important. There is market commentary asking whether LNG markets will link more to spot prices, and see greater convergence with regional markets, e.g. Henry Hub prices.

After the Fukushima disaster in 2011, Asian LNG spot prices were in the $14-20/mmBtu range. The current oversupply could see further weakening in the short-term. LNG spot prices are now more closely mapping European gas prices, becoming the flexible supply option.

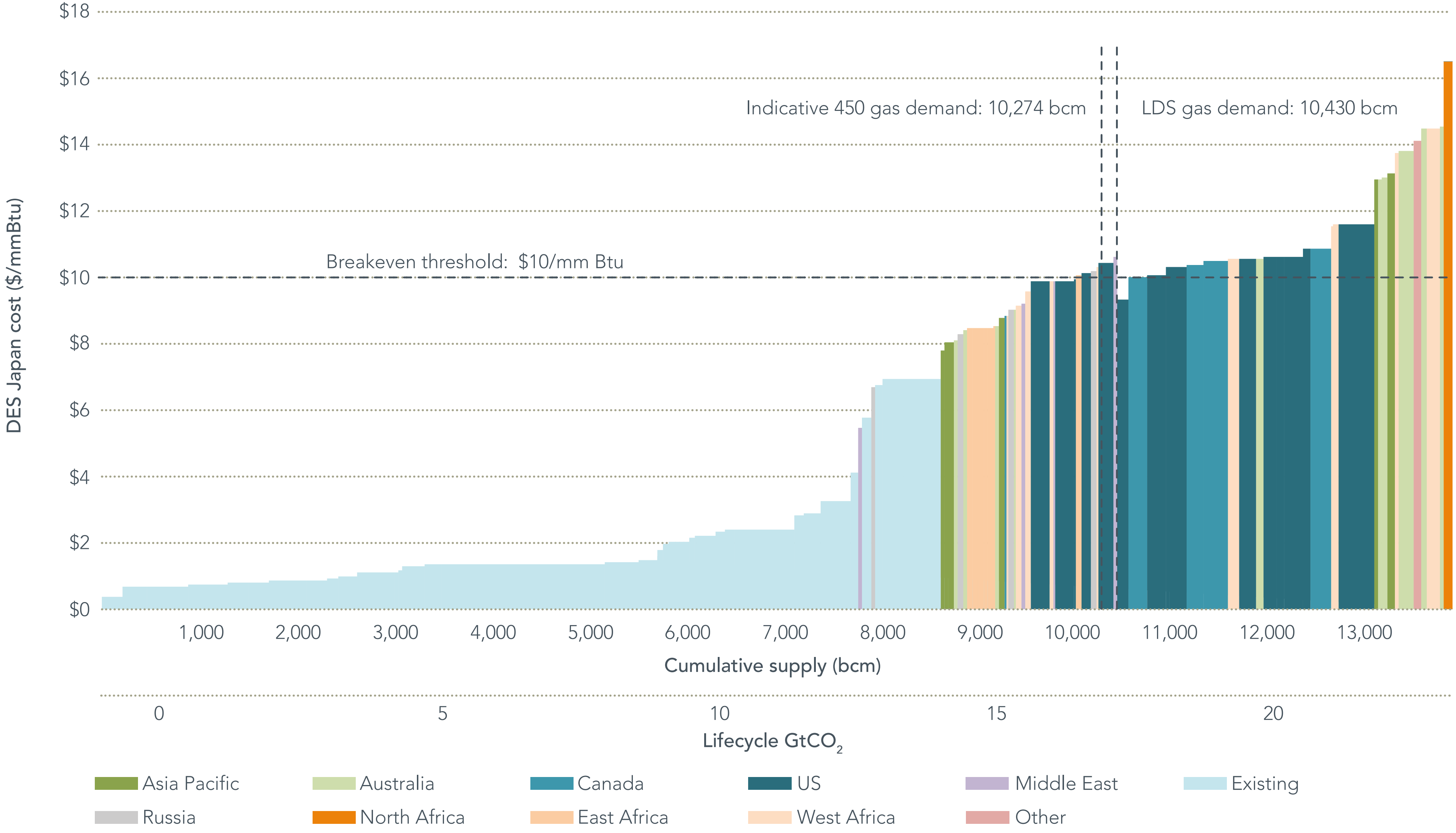
Carbon intensive

Increasing the proportion of gas supply from LNG makes it more difficult to achieve emissions reductions. This is because around one fifth of the delivered gas can be consumed in extraction, liquefaction, shipping and regasification.The change of state from gas to liquid is particularly energy intensive.This puts LNG at a disadvantage in carbon efficiency terms.

The most GHG intensive option is a combination of unconventional gas supplied via LNG infrastructure. Fortunately there is only around 17% that is LNG fed by US shale gas or Australian coal bed methane which breaks even under $10/mmBtu. Over half of the unneeded LNG capex relates to unconventional sources of gas supply, in the US and Canada. Removing this from the gas supply scenario is helpful in terms of limiting future greenhouse gas emissions.

This translates to a long term breakeven test of around $10/mmBtu

Figure 5: Global LNG cost supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

6. European carbon supply cost curve

The European market covered here includes piped domestic supply and piped imports from North Africa, Middle East, the Caspian and Russia.

Russian influence

Against this picture of fairly flat demand and well-supplied LNG markets, material new supply and uncontracted Russian gas is only needed from 2026 onwards in order to satisfy demand (although some is needed before this point in order to satisfy local demand). Based on the Brent price scenario of a flat $85/bbl throughout the period, oil-indexed imports from Russia remain competitive in the long term.

For Russian supply, a target price has been assumed in the model which would reflect a fair competitive position of Russian gas into Europe i.e. one that is competitive but not undercutting all the other new supply simply to gain political points and market share. This "target price" setting means Russia targets profitability above market share. This has the further effect of providing a balance of LNG and Russian piped gas in Europe, as states may wish to pursue given the perceived political risk of being too reliant on Russia for gas supplies.

This suggests that UK unconventionals will supply less than 1% of UK gas demand over the next decade

450 Scenario

There are a few tranches of supply that sit in the marginal cost band between the 450 and LDS scenarios. This includes the UK shale gas that is included in the supply in both scenarios. This is a function of the model limiting Russian supply. There is cheaper Russian supply that could displace UK unconventional gas production.

Unconventional impact on UK supply

If unconventionals are included by the model, only 3 bcm in the 450 scenario and 6 bcm in the LDS of unconventional production in the UK is included in total over the decade to 2025. This could increase post 2025, with the model estimates of volume and price indicating a further 80 bcm if Russian gas volumes are limited.

This compares to UK gas consumption of over 70 bcm per annum in recent years. This suggests that UK unconventionals will supply less than 1% of UK gas demand over the next decade (assuming demand stays at the same level). In practice this could easily be replaced by importing slightly more LNG to the UK.

LNG overflow

Oversupply in LNG markets over the next decade weighs on European hub prices as Europe acts as a "sink" for excess LNG supply. The prices show a similar trend to Asian LNG throughout, often in the $8–11/mmBtu range on an annual basis. This again translates to a long term breakeven threshold of around $10/mmBtu.

Indigenous gas uncompetitive

The model indicates that new indigenous gas above $10/mmBtu fails to make the cut in the low demand scenario. Some Russian production also is excess to requirements, but a large amount still clearly makes the cut.

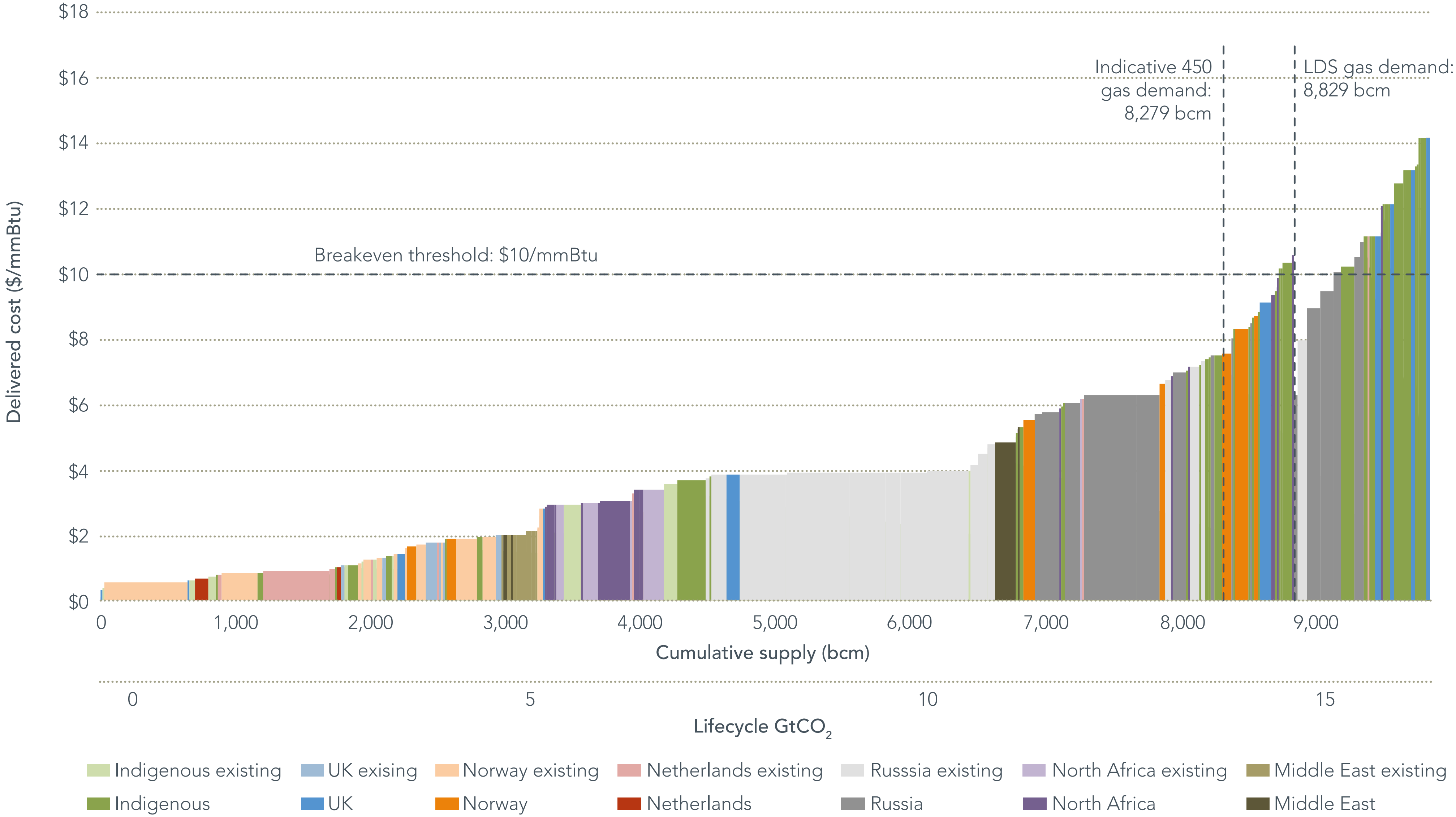
EU unconventionals

The model indicates that up to 5% of Europe's gas production could come from European unconventional sources over the next couple of decades in either scenario. This may end up being lower depending on which jurisdictions allow hydraulic fracturing to take place. Higher rates of unconventionals come through post 2025 than in the first decade, in the model.

Coal to gas switch

Gas has not seen its share of European power generation increase over the last decade. The weak EU carbon market and availability of cheap coal has not incentivised a new order in fossil fuel power generation. Over this period the previous EU utility business model has expired with the growth of decentralised renewables, as seen in Germany's 'Energiewende' (Agora, 2015, Carbon Tracker, 2015). Gas use can only grow at the expense of coal generation, given Europe's trajectory for emissions to 2050. Europe has objectives to cut emissions by 40% by 2030 and 80–95% by 2050 compared to 1990 levels. This does not leave much room for new large fossil-fuel based power plants that could run for decades.

Figure 6: Europe carbon supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

7. North America carbon supply cost curve

The approach for North America reflects the different gas industry operations and available dataset for the region. Most large new gas interests are amalgamated into production tranches (to reflect different drilling costs) rather than being at the project level. The sheer number of wells and plays makes it impossible to show the detail on this cost curve. This curve does not show unconstrained supply as this approach is not possible with the data due to the significant resources and short-term nature of shale gas plays. The chart shows the breakeven cost to the expected point of delivery. Prices will vary regionally, so it is not valid to compare to a single reference price such as Henry Hub.

Shale gas

The shale gas boom in the United States has altered the US energy picture, making gas cost competitive with coal in many states, especially where new air pollution requirements are coming in (Bloomberg, 2015). Even in a low demand scenario the model projects that shale gas will form nearly three-quarters of the US supply. The marginal supply is unconventional and the demand level will therefore determine the level of shale production required for the domestic market.

450 scenario

The difference between the scenarios is a 1,448 bcm tranche of US shale gas which does not get produced. The bulk of the fall-off in production (84%) occurs post-2025.

Financially sustainable?

The shorter term, less capital intensive, nature of shale gas in the United States means it is easier to adjust supply compared to an LNG plant. There is further capacity which companies are expecting to bring onstream; but companies could adjust their plans to respond to changes in demand and price. The resulting drop in revenues may place a financial strain on the smaller producers who have high levels of debt to service.

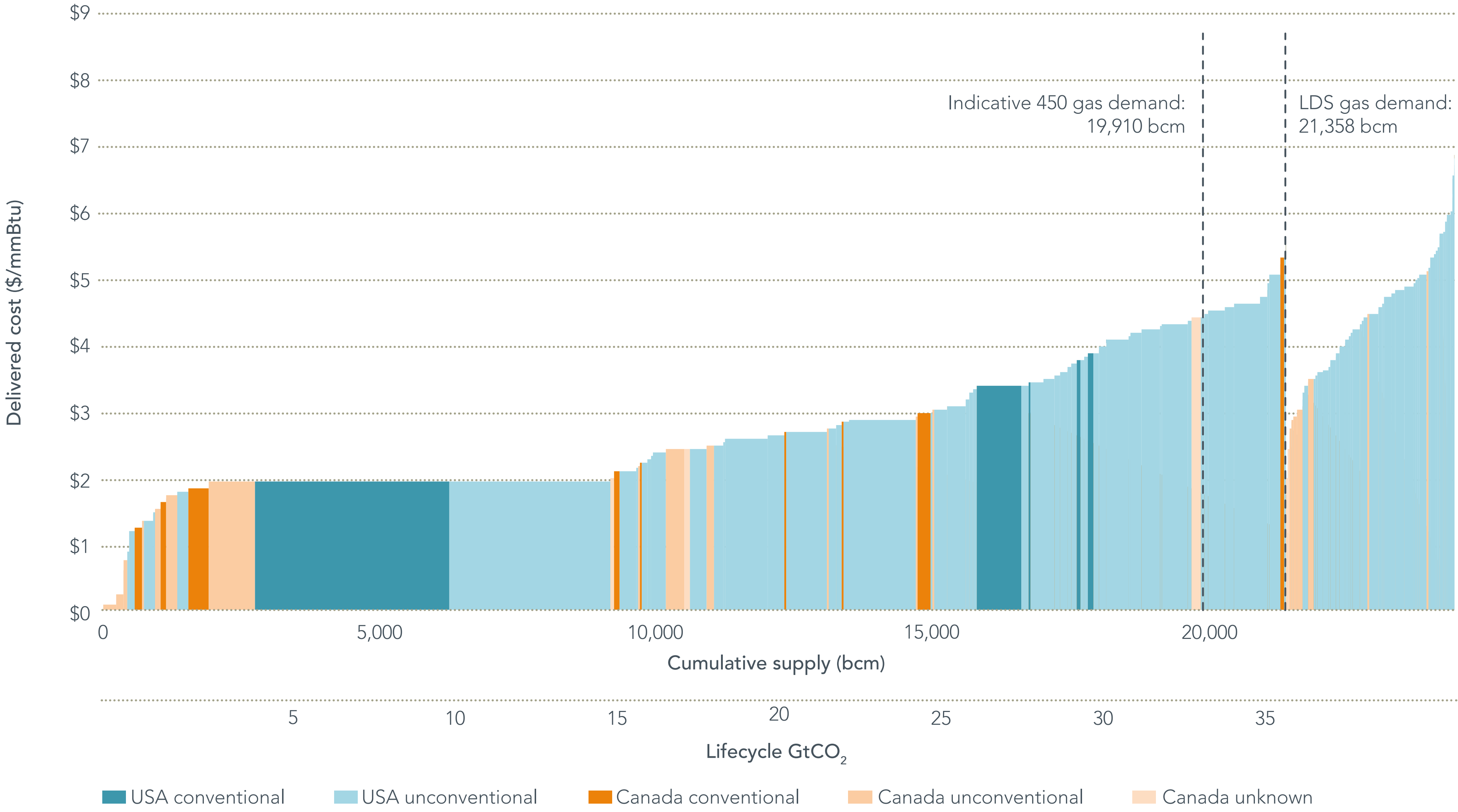
Price stability

Abundant domestic supply is consistent with average US natural gas prices remaining in the range seen in since the onset of the shale "revolution", largely in the $3–4/mmBtu range over the next decade and $4–5/mmBtu over the subsequent decade. We have not indicated a long-term breakeven price as the cost curve is too flat and the decision will be made on a case by case basis.

Regional distribution

The effect of applying a low demand scenario appears to be distributed across the production nodes, taking off the marginal barrels in each area. The model determines that newer plays with larger and higher cost drilling programmes (i.e. those likely to contribute greatest supply growth) are less certain. This is reflected in plays like Haynesville and Marcellus, where there is greater potential for variation. More expensive production from existing wells may be included in the supply, because their production is assumed to be locked in. Further, smaller plays may find a market despite being at the higher end of the cost curve, due to their local demand and infrastructure constraints. The structure of the US shale production makes it difficult to generalise any particular pattern.

Figure 7: North America carbon supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

8. Capex implications

Delivering the low demand scenario requires $1.5 trillion of capex to supply 41,236 bcm of supply over the 2015–35 period. The capex scenarios for the gas markets do not work in the same way as we have analysed them for coal or oil. The effects also vary for each regional market as a reflection of how they operate, and the nature of the projects.

Differences between scenarios

There is limited differences between capex required in the low demand and 450 scenarios due to the following factors:

- Minimal divergence in the Europe and LNG in the first decade
- The significant investment already sunk, particularly in LNG

As noted by broker research, the LNG market is already likely to be oversupplied to 2020 and beyond, with approved project capacity exceeding their projected demand (Goldman Sachs, 2015).

North America

The short-term nature of gas plays in US shale means it is easier for companies to adjust production in response to demand and price movements. Smaller companies may have financial pressures if they need to borrow to drill, and assume a higher gas price than actually results. There is no shortage of gas plays to develop – but unless exports are commercially viable the market is limited to within the continent. As such it does not make sense to talk about what capex could be overcommitted long-term, as the industry has more opportunity to adjust this.

Europe

Supply to the EU is bolstered by piped supply from its neighbours. The overflow of LNG at competitive prices provides an opportunity to diversify European gas supply further. There is a small amount of potential capex that is not needed in a low demand scenario that is above the $10/mmBtu breakeven threshold. The amount of capex that is not already committed is minimal. The degree of further capex required is flexible depending on the political risk situation and the price of LNG. This equates to $26 billion or around an extra 5% of capex over the next decade. $295 billion of the $551 billion capex required in the low demand scenario is for new projects.

Price risk

As LNG projects will largely be contracted in advance to secure demand for the production, this limits the risk of LNG production having no market. This leaves price risk as the main exposure for LNG producers. Traditionally most LNG contracts are linked to oil prices in some way. This has seen Asian LNG contract prices fall significantly over the last year as the oil price has come down. Europe is moving more towards a spot price market, and the nascent US market is dominated by traders pricing relative to the Henry Hub benchmark.

There is clearly a price risk for the producers, who have to take a view on long-term price trends rather than short-term movements. Those with greater exposure to the spot markets will carry higher risks if there continues to be oversupply of LNG. It is the off-takers who are contracted to buy the gas who are taking the risk of mis-reading demand for energy, and more specifically gas' share of it.

Focus on LNG

The infrastructure required for LNG makes it more capital intensive that the other markets considered. LNG projects are the area where it is possible to identify capex options for the future that have not yet been committed. In a low demand scenario there is a significant amount that gets pushed back beyond the next ten years for a final investment decision. Further deferral of projects will be needed if demand for LNG falls short of industry expectations.

We have identified $73bn of capex required to 2025 in a low demand scenario. There is a further $283bn of LNG projects not needed in the next decade.

This capex has not yet been approved by companies, so is not at risk of being wasted yet. However it does challenge the potential for these companies to grow their LNG businesses over the next decade beyond the ample capacity already in development at present.

LNG Capex

Potential LNG developments are concentrated in certain countries. In particular, Canada, US and Australia will be competing as to who gets to develop their LNG in a low demand scenario. Again the data shows how much of the expected LNG demand already has supply matched to it out to 2035. This results in fairly low requirements for further capex in the next ten years.

Limits to growth

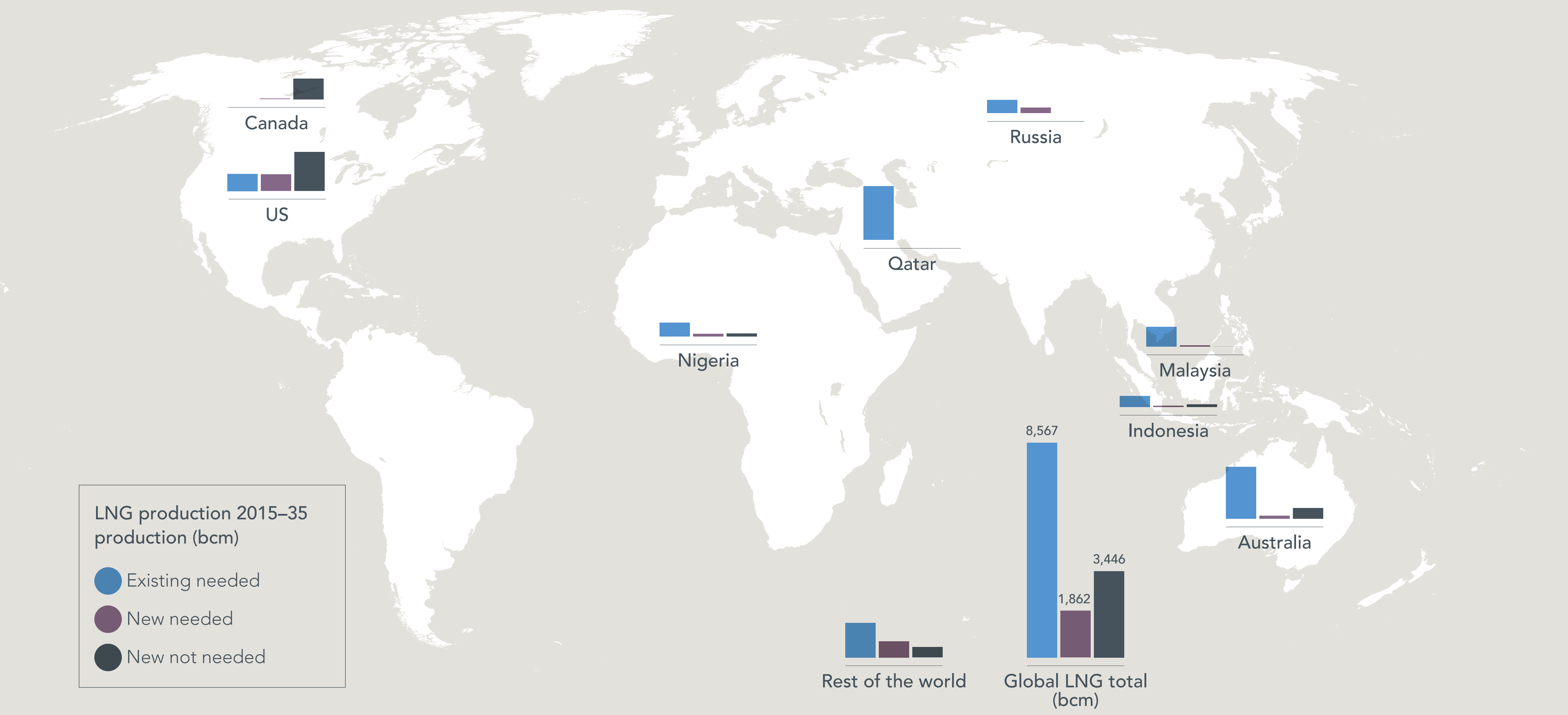
This picture questions whether the gas industry can expand its LNG industry significantly in the next decade beyond what has already been committed to. Companies have options on projects that are being evaluated and designed, but will not go ahead until the demand is certain. Shareholders need to question whether the strategy presentations of the companies add up – they can't all expand LNG as fast as they could build it.

Figure 8: LNG production & capex not needed in the LDS

	2015–35 Production (bcm)				2015–2025 Capex ($bn)			
	Existing	New			Existing	New		
Supply country	Needed	Needed	Not needed	% not needed	Needed	Needed	Not needed	% not needed
Australia	2,069	123	418	77%	87	0	68	100%
Canada	0	22	824	97%	0	0	82	100%
Indonesia	434	50	110	69%	0	0	10	100%
Malaysia	788	45	0	0%	6	0	0	0%
Nigeria	552	100	119	54%	0	0	0	0%
Qatar	2,135	0	0	0%	3	0	0	0%
Russia	527	210	0	0%	35	0	11	100%
US	682	664	1,558	70%	17	26	71	74%
Rest of world	1,382	648	417	39%	4	48	42	47%
Global LNG total	8,567	1,862	3,446	65%	152	73	283	79%

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Figure 9: Map of LNG production needed and not needed in LDS



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Projects deferred

The table shows the breakdown of LNG capex to 2025 and production to 2035 for the 20 largest companies in terms of unneeded capex in the low demand scenario. These are projects that companies could develop in the future but have not made a final investment decision on. In the low demand scenario most of these get deferred beyond the next decade.

Production already covered

Around 82% of production required to 2035 in a low demand scenario is covered by LNG projects that are already under development or producing. This leaves very little opportunity for new LNG projects in this scenario. Amongst the top 20 companies, only ENI, Cheniere and Noble have additional projects that are needed to meet LNG demand under the LDS. Below this are a long list of smaller operators and projects that would also be included in the low demand scenario according to the model.

Existing exposure

The table below lists companies by total potential capex to 2025. The data indicates which companies have already secured a share of the LNG market for the next 20 years. It is not surprising that many of the companies who have options for the future are those that have led the way in developing an LNG portfolio. Amongst the majors Total stands out as only having existing projects, with no major new LNG projects modelled as taking FID within the next decade. This reflects the significant position Total has already secured in the LNG market.

LNG concentration

The oil majors have varying exposure to LNG. Shell has made the biggest play with its proposed takeover of BG Group. Firstly it is worth noting that a significant amount of LNG is already under development by these companies – so they have good exposure to the market that has already been contracted. Beyond this there is a question mark over the level of investment that will be required over the next decade.

At this point there is not a major problem in deferring an LNG project for a decade. However it does assume there will be a conducive demand and price environment that warrants its development in 2025 or beyond.

M&A activity always brings company profiles and strategy under greater scrutiny, especially at the scale of Shell buying BG Group. Aside from boosting its access to oil reserves, this concentrates Shell's options in LNG. Shell's offer is based on Brent oil prices returning to around $90, which translates to an oil-indexed LNG price of around $14–15/mmBtu based on typical contract pricing formulae. The long-term gas price in our low demand scenario is around $10/mmBtu. This would mean oil prices averaging around $62–63 long-term.

The combined entity has $59bn of new projects that are not progressed by the model to 2025. This picture does not improve much to 2035, with $85bn of new projects not needed, and only $6bn of projects going ahead in the low demand scenario modelled.

Figure 10: Company exposure to LNG capex and production

		2015–2025 Capex ($bn)					2015–35 Production (bcm)			
Rank	Company	Total	Existing needed (LDS)	New needed (LDS)	New not needed	% new not needed	Existing needed (LDS)	New needed (LDS)	Total needed (LDS)	% of total needed
1	Chevron	34.8	16.9	0.0	17.8	100%	428	35	463	4.7%
2	Shell	34.7	9.0	0.0	25.6	100%	646	46	691	7.0%
3	BG	33.7	0.4	0.0	33.2	100%	218	0	218	2.2%
4	Cheniere	27.0	5.6	13.5	7.8	37%	379	160	539	5.5%
5	ExxonMobil	21.4	5.0	0.0	16.4	100%	586	120	706	7.1%
6	NOVATEK	21.0	21.0	0.0	0.0	-	188	37	225	2.3%
7	PETRONAS	20.6	7.6	0.0	13.0	100%	636	41	677	6.8%
8	Woodside Petroleum	17.4	4.6	0.0	12.8	100%	169	0	169	1.7%
9	Total	15.3	15.3	0.0	0.0	-	430	48	478	4.8%
10	INPEX Corporation	13.5	13.5	0.0	0.0	-	151	29	180	1.8%
11	Apache	12.4	1.7	0.0	10.7	100%	27	3	30	0.3%
12	Noble Energy	11.9	0.0	5.7	6.3	52%	0	23	23	0.2%
13	Eni East Africa	11.2	0.0	11.2	0.0	0%	0	21	21	0.2%
14	Sempra	10.1	3.8	0.0	6.3	100%	113	0	113	1.1%
15	Govt of Indonesia	9.5	0.0	0.0	9.5	100%	0	50	50	0.5%
16	Qatar Petroleum	9.2	1.8	0.0	7.4	100%	1,443	141	1,584	16.0%
17	Kinder Morgan	8.7	0.0	0.0	8.7	100%	0	15	15	0.2%
18	PetroChina	8.3	0.0	0.0	8.3	100%	0	0	0	0.0%
19	BP	8.1	1.0	0.0	7.1	100%	155	8	163	1.6%
20	Energy Transfer Ptnrs	7.6	0.0	0.0	7.6	100%	0	0	0	0.0%
										64.2%
-	Shell + BG aggregate	68.4	9.5	0.0	58.9	100%	863	46	909	9%

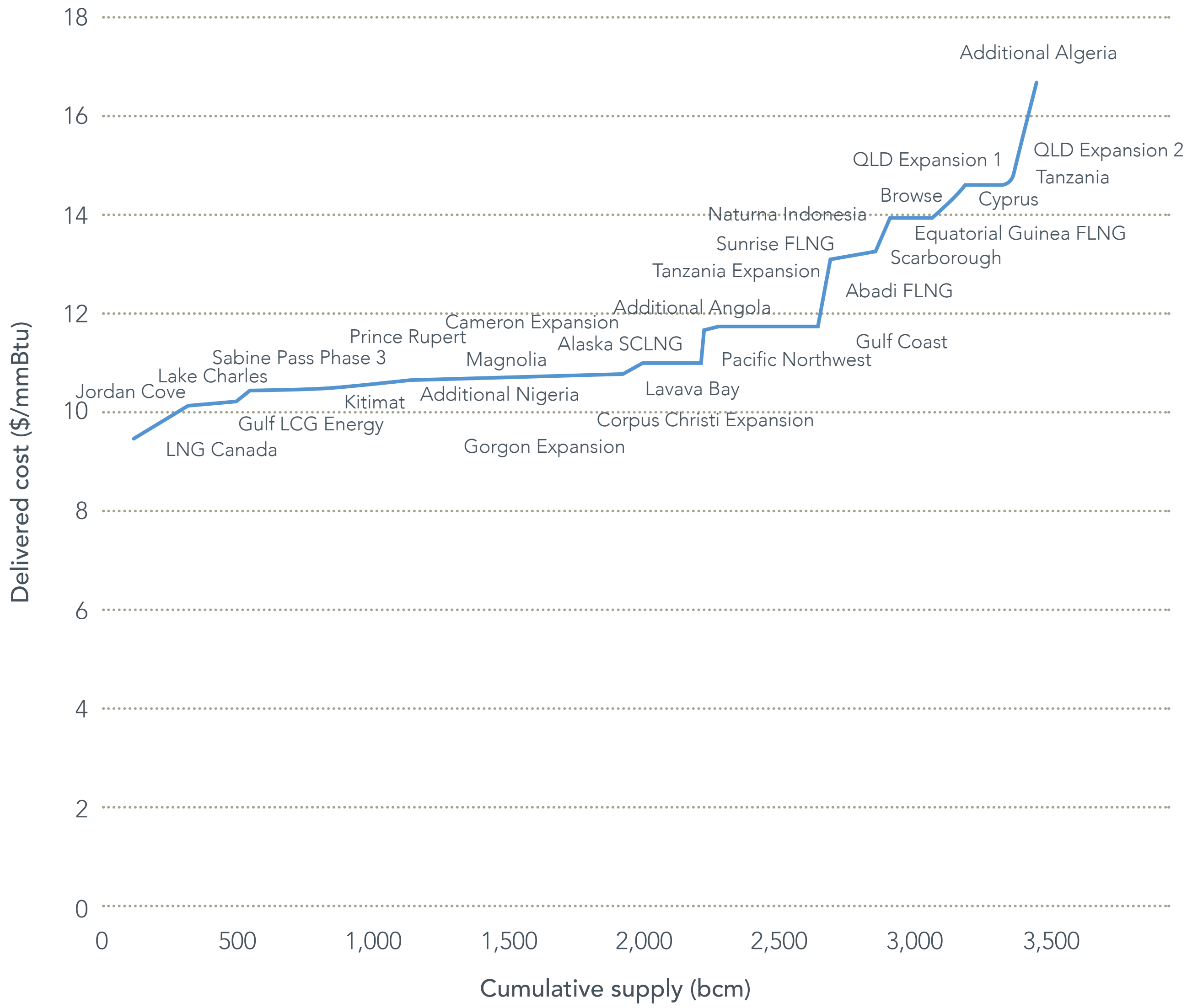
Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

LNG projects not making the cut at $10/mmBtu

The cost curve shows which LNG projects are at the high end of the cost curve, and are not needed in the low demand scenario. This reflects that generally the new US and Canada projects are just above the $10/mmBtu level, with Australian projects even further up the curve. Projects may move along the curve over time depending on changes to cost elements and foreign exchange rates.

This demonstrates to investors that in a low gas demand scenario there are projects that companies may have under consideration which may not be needed in the next couple of decades. This set of projects reflect those identified at the time of modelling as credible projects mentioned by companies which could balance a larger global LNG market, but are not an exhaustive list.

Figure 11: LNG projects not needed in low demand scenario to 2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

9. Conclusions and recommendations

Less potential for wasted capital

The current structure of the gas industry makes it less prone than oil or coal to wasting capital on projects that may not be needed in a low demand scenario. In particular LNG plants are so capital intensive they are usually approved only once the majority of production has been contracted. US unconventionals offer more flexibility due to being a more short-term play – the question is how sustainable the business model is for highly leveraged smaller operators.

Limits to growth

Investors should scrutinise the true potential for growth of LNG businesses over the next decade. The current oversupply of LNG means there is already a pipeline of projects waiting to be next in line to take final investment decision. It is always good to have options, but it is not clear when these projects will actually become real and generate value for shareholders. Shareholders should review how many LNG projects requiring over $10/mmBtu break even sit in the future strategy of the companies they invest in.

Price risk

Gas producers have limited direct exposure to demand risk, so it is price risk that they are more sensitive to. Again this is a regionalised picture with the regions interacting, rather than a simple conclusion. LNG contracts have traditionally been linked to the oil price – leading to exposure to oil price movements. European production is now seeing LNG oversupply compete with its marginal production. The US will continue to need gas prices to continue to strike a balance between competitiveness and revenues.

How much growth?

There is room for some growth in gas supply in the next 20 years. The exact amount in each region will depend on a range of factors, indicating it is not as simple as expecting a coal to gas switch. Cheaper renewables, greater efficiency, new storage technologies, higher carbon prices, and relative commodity prices will all play their part.

For how long?

The continued efforts to agree emissions reductions and improve air quality represent a clear direction of travel for reduced use of fossil fuels. This is reflected in the recent G7 message supporting the phase out of fossil fuels and transformation of energy sectors by 2050; and the Track Zero initiative, co-ordinating governments and businesses seeking to deliver net zero emissions by 2050. Any new gas plants being approved now may have a limited lifetime.

Room for unconventionals?

There appears limited scope for growth of unconventionals outside of the US. Firstly this is due to these projects being in the marginal range of the cost curves. This means they need higher prices to be justified, and also that there is Russian gas that is cheaper to supply. Secondly environmental questions remain, including the significance of fugitive emissions which needs resolving for all gas. Reducing US demand cuts US shale production. Projects to convert US shale into LNG for export are the most GHG intensive option and don't fit in a low carbon future.

Allocating the carbon budget

Having now analysed oil, coal and gas it brings into focus the potential trade-offs between the fossil fuels in how future energy scenarios may play out. This may get nudged in either direction by factors including CCS, carbon prices, and fugitive emissions. However the conclusion is similar – there is a finite amount of fossil fuels that can be burnt over the next few decades if we are to prevent dangerous levels of climate change.

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