AVOID 2

Can we avoid dangerous climate change?

The impact of shale gas on the cost and feasibility of meeting climate targets - a global energy system model analysis and an exploration of uncertainties

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Authors: Sheridan Few[1], Ajay Gambhir[1], Adam Hawkes[1], Stephane Mangeon[1], Dan Bernie[2] and Jason Lowe[2]

[1]Grantham Institute, Imperial College London

[2] Met Office Hadley Centre

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Non-technical summary

This study explores the implications of shale gas extraction on the cost and feasibility of meeting a 2°C long-term temperature goal which, as with the other AVOID 2 mitigation feasibility analysis, is taken as limiting average global temperature rise in 2100 to below 2°C above pre-industrial levels, with 50% likelihood[1]. The study finds that there is a wide range of estimates of the size of the resource, as well as extraction cost, of shale gas. There is also a wide range of extraction cost estimates for conventional gas. As such, the potential economic costs and benefits of exploiting shale gas are highly sensitive to assumptions made on resource and costs. Hence a scenario approach is used, to illustrate the impact of shale gas extraction on the global cost of meeting a 2°C target, as well as the rate of emissions reduction required to do so, using a range of plausible cost estimates. Specifically, scenarios use high, medium and low costs for both shale and conventional gas resources, in different combinations.

The principal tool of analysis is the TIAM-Grantham global energy systems model as used throughout the AVOID 2 "rates of decarbonisation" analysis. The model simulates the cost-optimal evolution of the global energy system under input assumptions on future energy demand, energy technology and fossil fuel resource costs, and imposed climate targets. The primary findings of this study are:

1. In scenarios that deliver a cost-optimal pathway to meeting the 2°C goal, natural gas as a whole (i.e. from both conventional and shale sources) becomes an increasingly important primary energy resource in the next two decades, rising from 20% of global energy supply today to 30-40% in 2030 across the different gas cost scenarios explored. In the period 2016 -2040, 4,600 – 5,500 EJ of natural gas is extracted, 60 – 70% of proven global reserves, as estimated by the Energy Information Administration.

2. In the 2°C scenario where the lower end of the shale gas cost range is combined with the higher end of conventional gas costs, shale gas constitutes over 10% of total primary energy during the period 2020-2040 (peaking at 18% in 2030). This is the most optimistic scenario with regard to shale gas costs relative to conventional gas costs, with the other cost scenarios resulting in shale gas making up 6% or less of total global primary energy by 2040. In no scenario does shale gas make up the majority of total natural gas supply over this period, given the availability of relatively low-cost conventional gas (even where its costs are at the high end of the range of existing estimates). Beyond 2040, in all scenarios shale gas falls to between 2 and 4% of total global primary energy by 2100, whilst total natural gas falls to between 9 and 11% of total primary energy by 2100;

3. The global demand for all (conventional and shale) natural gas over the 21st century in the 2°C scenarios would be reduced by 38-47% if carbon capture and storage (CCS) technology is not available, and the demand for shale gas in particular would reduce by 20-67% without CCS. The ranges reflect the different cost assumptions for shale and conventional gas;

4. The incremental benefit (in terms of reductions to the global energy system cost) of adding shale gas to the global energy mix is relatively small, even under the most favourable cost assumptions for shale gas. Comparing a scenario with the highest cost in the range for

[1] Note that this target is slightly less stringent than the IPCC target of a 66% chance of limiting global warming to 2°C in any given year [71]. Also to note that the analysis presented here predates the amendment to the UNFCCC text on the long-term temperature goal, to "well below 2°C", as agreed in Paris in December 2015 [60]

conventional gas and no shale gas, with a scenario in which shale gas is then made available at the lowest costs in its range, the cumulative saving in global energy system costs to 2100 is 0.4%.

5. There is little discernible impact of shale gas exploitation on global CO_2 emissions reduction rates under the 2^oC goal, which are comparable across scenarios – however this does not factor in any impacts shale gas exploitation could have on investment in or appetite for alternative energy technologies or resources;

6. A "dash for shale gas", in which there is forced extraction of the lower and medium cost bands of the global shale gas resource to 2050 (even where it is not lower in cost than available conventional gas), would result in cumulative global mitigation costs of 1.32–1.46% of GDP to 2100, relative to 1.05-1.10% of GDP where shale gas is available but where there is no forced dash for shale gas (the ranges reflecting the range of assumptions on cost of conventional and shale gas).

The study also presents scenarios in which shale gas exploitation leads to a rise in capital financing rates of low-carbon technologies, as well as higher-than-planned methane leakage rates, in order to illustrate the consequences of these potential factors. As expected, raised low-carbon technology capital financing rates would raise overall mitigation costs, whilst higher methane leakage rates would increase the difficulty of meeting long-term temperature goals. However, given current uncertainty around methane leakage and the ability to monitor and mitigate this at low cost, as well as a lack of robust evidence on the impact of shale gas exploitation on alternative energy technology and resource financing rates, this analysis remains illustrative only.

In summary, this analysis suggests that global shale gas availability would not make a significant (positive or negative) impact on the cost and feasibility of an energy system transition consistent with the 2°C goal, nor significantly affect the cost-optimal decarbonisation pathway globally. However, unsurprisingly, any forced exploitation of shale gas even where uneconomic compared to conventional sources of gas could lead to higher global mitigation costs overall. These findings should be taken in the context of the uncertainties already outlined, whilst also noting that they derive from one global energy systems model only.

Media interest

There is continuing media interest in shale gas exploration in the UK and worldwide. As such, these report findings could inform the broader media debate as to the cost-effectiveness and climate impacts of shale gas.

Contents

1 Introduction

In recent years, there has been considerable global and regional interest in shale gas, which it has been suggested could play a role as a bridging fuel to a low-carbon future [1], [2] and which has led to a huge increase in indigenous gas production in the US [3] There remains, however, considerable uncertainty over shale gas resource availability and extraction costs, as well as the fugitive methane emissions associated with shale gas extraction.

This study considers the impact of a range of shale gas cost and availability assessments on mitigation scenarios aimed at achieving a limit to global warming of below 2°C in 2100, with a 50% likelihood[2]. The study first discusses existing analysis and uncertainty around shale gas resource availability, extraction costs and fugitive methane emissions. It then describes how a global energy systems model (TIAM-Grantham) is used to examine the impacts of shale gas availability on global mitigation scenarios aimed at achieving a long-term temperature goal of below 2°C in 2100 (with 50% likelihood), the results of this analysis, which focuses on the global energy system costs, shale gas demand and primary energy usage impacts, and finally the implications of this analysis.

1.1 What is shale gas and how does it differ from conventional gas?

Shale gas represents natural gas trapped within shale rock formations. Historically, gas has mostly been extracted from more porous rocks such as sandstone (referred to as conventional gas extraction). Shale is less porous, and requires horizontal drilling, and hydraulic fracturing (also known as “fracking”), in order to enable gas to flow from a well (see Figure 1). Both of these technologies have also been used in conventional gas extraction [4], but shale is harder and less brittle than rocks in conventional formations, and techniques to frack shale with confidence have only been developed by American energy companies in the last 10 – 20 years [5].

[2] To note that the analysis presented here predates the amendment to the UNFCCC text on the long-term temperature goal, to “well below 2ºC”, as agreed in Paris in December 2015 [60]

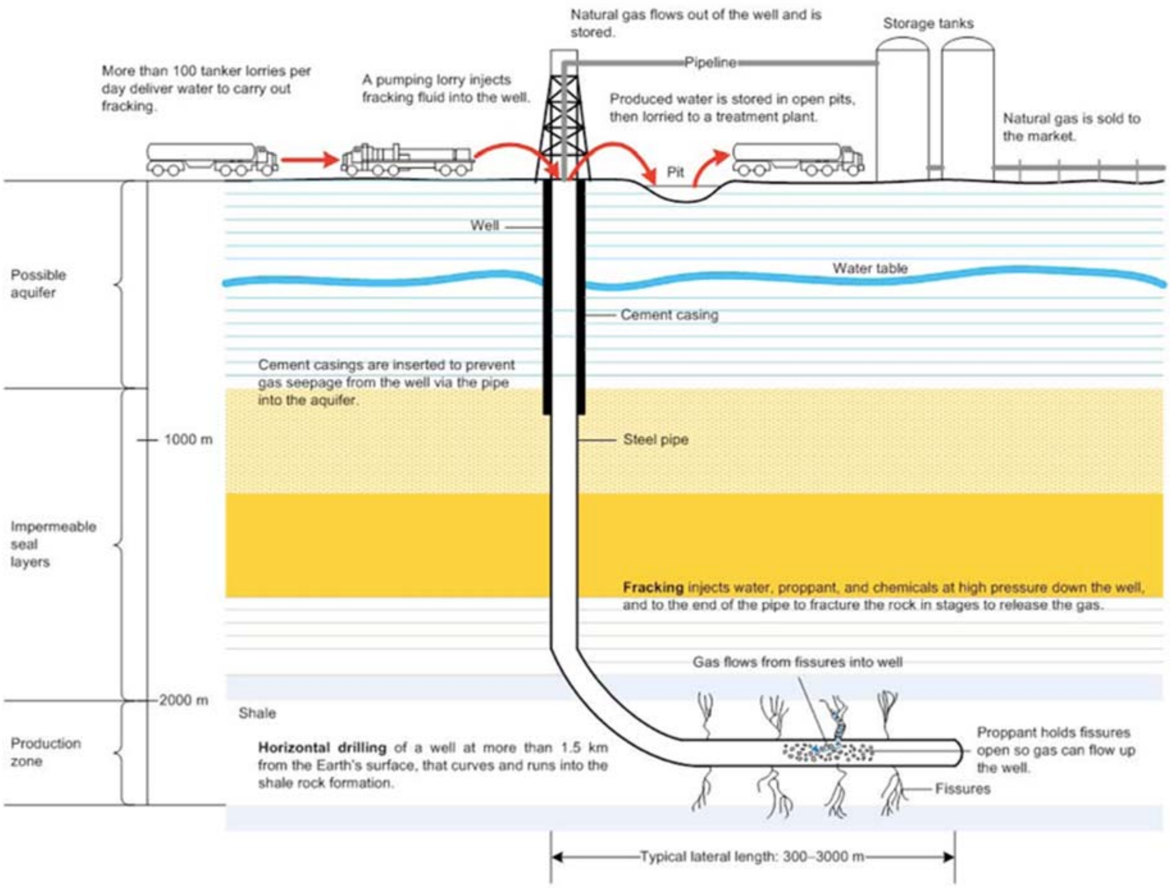

Figure 1: Shale gas operation with fracking, reproduced from Hirst et al. [5]**, adapted from Granberg** [6]**.**

A set of discovered, undiscovered or possible natural gas accumulations that exhibit similar geological characteristics is often referred to as a "play". Shale plays are located within basins, which are large-scale geologic depressions, often hundreds of miles across, which also may contain other oil and natural gas resources[3] [7]. The US Energy Information Administration (EIA) identifies shale plays in the USA which vary in size from hundreds to tens of thousands of square miles [8]. More than 80% of shale gas production in the US comes from five of the largest plays [9]. During a mining operation, a number of wells will be constructed within such a play, from which gas will be extracted (see Figure 1). Density of wells is variable, and there is limited data available on this, but the IEA [10] indicates that shale gas extraction typically requires a significantly higher density of wells (more than one well per square kilometre identified in the Barnett play) than conventional gas (estimated at less than one well per ten square kilometres).

1.2 Why has shale gas extraction been proposed?

The possible role of shale gas in a future energy system has been the subject of much debate over recent years. Hydraulic fracturing for shale gas in the US has led to a tenfold increase in production of shale gas between 2006 and 2010, reaching 47% of total U.S. dry natural gas production in 2013. Over this period, wellhead gas prices, and gas imports into the US, have both fallen significantly [3]. The possibility of emulating this phenomenon

[3] The term field appears to be used to refer both to individual plays and to entire basins. We avoid use of the term "field" in this report.

worldwide has led to further exploration of reserves in other regions, and led the IEA to describe natural gas as “poised to enter a golden age” [10].

The CO_2 emissions associated with electricity generation from combustion of natural gas are approximately half of those produced when generating electricity from coal. Between 2007 and 2013, CO2 emissions in the USA are reported to have fallen by 11% [11]. A 4% reduction in CO2 emissions over this period has been attributed to a shift in the fuel mix from use of coal to the use of natural gas, with a decrease in consumption volume and changes in production structure making up other significant contributing factors [12]. In addition, gas turbines are able to provide flexible generation, helping to balance supply form intermittent renewable electricity sources such as wind and solar PV [13]. These factors combined have led some analysts to conclude that natural gas could play an important role in supplying world energy needs over the coming decades as we transition to a less carbon-intensive energy system, with President Obama describing fracking as a “bridge” to a clean energy future [14].

1.3 What are the known risks?

A number of economic and environmental risks have been associated with widespread extraction of shale gas. These risks arise from uncertainties in resource size, extraction costs, the potential lock-in to natural gas assets and infrastructure, diversion of funds from lower carbon technologies, fugitive methane emissions, as well as local environmental impacts and acceptability [5].

There is significant uncertainty in the size of the global shale gas resource, which has so far largely been assessed on the basis of the size of shale formations, and assumed gas concentrations. Due to limited experience with shale gas, particularly outside of the United States, there have been relatively few estimates of shale gas extraction costs, none of which could be described as authoritative. Stevens [15] identifies a number of geological, regulatory, and industrial factors likely to make shale gas extraction less favourable in the UK than the US, concluding that policy interventions would be necessary to bring about a “shale gas revolution” in the UK. Resource size and extraction costs are considered in more detail in section 2.

Concerns have been raised surrounding the development of gas infrastructure, which might lead to long-term lock-in to gas when climate targets require a move to lower-carbon technologies. Related to this is a possible diversion of public and private funding away from cleaner technologies, which might lead to their being developed and deployed more slowly, with possible implications both for the economy and the environment [5].

The rate of fugitive methane leakage from shale gas extraction is a crucial factor in determining the climate impact of shale gas extraction. Methane has a significantly higher global warming potential than CO_2, such that if leakage rates are higher than around 4%, then the 20-year climate benefits of using gas rather than coal for electrical power are eradicated [16]. Leakage rates ranging from less than 0.5% to above 10% have been reported, using different measurement methodologies. A more detailed overview of literature on leakage rates is provided in section 2.

Other concerns include impact of hydraulic fracturing to surface water, air, and land, around which hydraulic fracturing is subject to exemptions from a number of regulations in the US [17], and strong local opposition in some communities [18]. A draft report from the US Environmental Protection Agency [19] concludes contamination of drinking water associated with hydraulic fracturing has taken place in some cases. The local environmental impacts of shale gas extraction are discussed in Hirst et al. [5], and the importance of information collection, access, and dissemination to support evidence-based shale gas policies are outlined by Gamper-Rabindran [20]. These impacts fall outside of the scope of this report.

1.4 Other unconventional sources of gas

McGlade et al. [21] identify two other unconventional sources of gas:

- **Tight gas:** gas trapped in relatively impermeable hard rock, limestone or sandstone, sometimes with quantified limit of permeability.
- **Coal bed methane (CBM):** gas trapped in coal seams, adsorbed in the solid matrix of the coal.

These unconventional sources do not form the core of this study, but are discussed in the model results in section 4.

2 Literature on shale gas resource availability, extraction costs, and fugitive emissions

2.1 Levels of supply

There remains a lack of authoritative data on the quantity and geographical distribution of supplies of shale gas. McGlade et al. [21] provide an overview of terminology surrounding gas resources, reproduced in Table 1, and a review of literature on shale gas reserves.

Table 1: Interpretation of resource terminology, reproduced from [21]

Name	**Short Description**
Original gas in place (OGIP)	Total volume present
Ultimately recoverable resources (URR)	Total volume recoverable over all time
Technically recoverable resources (TRR)	Recoverable with current technology
Economically recoverable resources (ERR)	Economically recoverable with current technology

In 1997, Rogner [22] made an early estimate of original gas in place (OGIP) volumes in shale formations globally, assuming the gas content of global shales was comparable to that estimated for those in the United States. However, Rogner warns that "in many cases [these estimates] are highly speculative"[22]. A number of subsequent estimates of technically recoverable reserves (TRRs) apply recovery rates of between 10 and 40% to Rogner's [22] estimates [21] - this range reflects the current level of high uncertainty around the viability of recovering shale gas from different areas.

In 2011, Advanced Resources International (ARI) made an assessment of TRRs of shale formations in 14 regions outside of the US for the US Energy Information Administration (EIA), based upon geology of shale formations, and data on pressure, temperature, porosity, and shale thickness (where such data was available), using recovery rates between 15 and 35% [23]. McGlade et al. [21] describe the 2011 ARI study as "the new benchmark". McGlade et al. combine TRR estimates in the literature to produce their own "low", "central", and "high" global estimates, broken down into individual regions, of which the ARI estimates [23], as well as those of Medlock [24] form the bulk. McGlade et al. give a central estimate of 193.2 Tcm (7195 EJ) of shale gas available. In 2013, the ARI [25] published a more detailed study of TRR of shale resource, identifying 234 Tcm (8220 EJ) in 26 regions, containing 41 individual countries, but acknowledge that their estimates remain in the early stages. In 2015, the Federal Institute for Geosciences and Natural Resources (BGR) [26] published a study stating that around 215 Tcm (8006 EJ) are available globally, broadly in line with McGlade et al.'s earlier estimates (although methodological details are not provided, and this similarity may be due to a reliance on the a similar set of sources).

In some cases, more detailed studies of individual shale formations have suggested values published by the ARI significantly overestimate the technical resource of shale. A 2012 study by the Polish Geological Society [27] on supplies of shale gas estimates supplies around a tenth of those predicted by the ARI [23], and notes the large uncertainty in estimated values, with highest estimates still around half of that identified in the ARI's 2013 study. The U.S. Geological Survey estimated the Marcellus shale play contains 80% less gas than ARI's 2011 estimate, following which the ARI revised their estimate down for this play by 67% [28].

2.2 Field depletion and economic feasibility

As well as uncertainty around resource estimates, there is also considerable uncertainty surrounding the manner in which individual shale plays and wells may deplete, and hence the quantity of economically recoverable shale resources. As shale gas extraction has only been widespread in the US for less than a decade, assumptions of long term decline in production from shale plays are understandably somewhat speculative.

A typical shale gas play will contain a number of "sweet spots", in which methane is more concentrated. Typically, wells will be drilled in the most economic "sweet spots" first[29], [30]. It has been suggested that the economic investment currently required to build a higher number of wells to replace declining supply from higher productivity wells is not being, and will not be, recuperated at current gas prices [30].

Furthermore, there has been criticism of the assumed drop-off rates of shale gas wells assumed by many in the industry, with the assertion that "industry practice of fitting hyperbolic curves to data on declining productivity, and inferring lifetimes of 40 years or more, is too optimistic [….] Because production declines more steeply than these models typically suggest, the method often overestimates ultimate recoveries and economic performance" [30]. In a later report, Hughes forecasts "most likely" total production from major shale plays to be ~2/3 of that projected by the EIA up to 2040 [31]. There are significant differences between sources surrounding likely future productivity of shale gas plays. [32].[4]

All of the above papers are focussed on US shale gas supply, and it is not straightforward to determine their implication for global supply-cost curve estimations. However, they imply that there could be significant space for downward revision of estimates if those forecasts are produced with methods similar to those used to project US shale production. However, other commentators have contested this interpretation, taking recent history of shale gas production as evidence that future estimates are realistic [33].

In summary, shale gas supply and cost scenarios used in global assessment models could be significantly over-optimistic although this is an area of uncertainty and ongoing disagreement between different analysts.

2.3 Methane leakage rates

The rate of methane leakage is a crucial factor in determining the climate impact of shale gas extraction, as it is with all natural gas extraction. Methane has a significantly higher global warming potential than CO_2 (as 86 times higher over a 20 year timeframe, and 34 times higher over a 100 year time frame [34]) due to the differing absorption profiles and atmospheric lifetimes of the two gases. As such if leakage rates are higher than around 4%, then the 20-year climate benefits of using gas rather than coal for electrical power are eradicated [16]. Emissions from natural gas are typically divided into "upstream" emissions

[4] It should be noted that Inman's article has been criticised by the EIA for the simplicity of its analysis, its perceived mis-portrayal of the relationship between the EIA and the University of Texas, and its presentation of EIA's scenarios as forecasts [72]. However, the magnitude of difference between scenarios proposed by the EIA and projections presented by University of Texas remains significant.

associated with extraction, and “downstream” emissions associated with storage and transmission. A summary of literature on methane emissions associated with shale gas extraction is provided in Figure 2 below, broadly categorised according to methodology: review, bottom-up, atmospheric, and satellite.

Bottom-up measurements sum sources of emissions measured in collaboration with industry when gas is being extracted. Atmospheric measurements measure the concentration of methane in the neighbourhood of sources of gas extraction (although it should be noted that the difficulty of source apportionment represents a fundamental difficulty in such studies). Results from satellite measurements taken prior to and during the shale boom in the US are also included. Both atmospheric and satellite measurements indicate that emissions associated with shale gas extraction have often been significantly higher than indicated by bottom-up studies. In addition, Miller et al. [35] review atmospheric measurements in the US, concluding that the EPA underestimates methane emissions in its inventory studies by a factor of 1.5, implying that regional methane emissions due to fossil fuel extraction and processing could be 4.9 ±2.6 times larger than in the Emissions Database for Global Atmospheric Research (EDGAR) [36], described by the authors as the most comprehensive global methane inventory.

Reports by Howard et al. [37], [38] state that a sensor failure is likely to have led to significant underestimates in fugitive emissions in bottom-up studies, in particular the Allen et al.’s major 2013 study of emissions in a large number of US gas wells [39]. Some of these claims have been contested, and this remains an area of ongoing debate and analysis [38] [40].

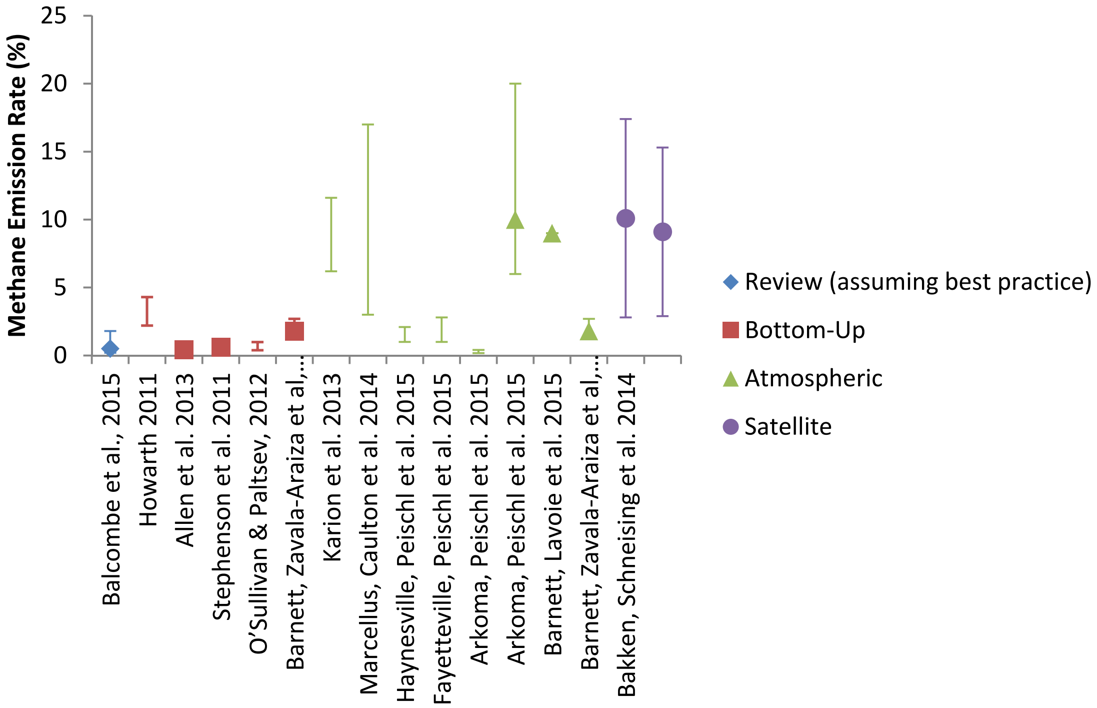

Figure 2: A summary of literature on methane emissions associated with shale gas extraction. More details of these studies are provided in Annex A.

Balcombe et al's (2015) literature review on fugitive emissions from shale gas extraction presents a range of methane leakage rates of 0.2 – 1.8% assuming best practice. This range excludes emissions from "super-emitters", defined as "an emission source that leaks far in excess of the average". The authors state an expectation that these could be largely eliminated if more stringent procedures were applied, but note technical uncertainty in some areas (liquids unloading, in particular), and challenges in monitoring wells. A report prepared for the US Environmental Defense Fund estimates that, taking savings into account, a 40% reduction in onshore methane emissions is possible at a net cost of less than $0.01/Mcf (~$0.01/MJ) of gas produced [41], and the International Energy Agency indicate that policy directed towards reduction in upstream methane emissions could play an important role in climate change mitigation [42].

It should be noted that conventional gas extraction is also associated with fugitive emissions, and a recent study identified higher production-normalised emissions rates in conventional gas extraction sites than shale gas extraction sites in the Marcellus region, attributed to a greater prevalence of avoidable process operating conditions (e.g. unresolved equipment maintenance issues) [43].

2.4 Shale gas supply curves in previous energy modelling studies

There have been a number of key studies on the impacts of shale gas on greenhouse gas emissions in recent years, which are summarised in Table 2.

Table 2: A summary of key studies on the impacts of shale gas on greenhouse gas emissions

Study	Scope	Methodology/Assumptions	Results/Key Findings
McJeon et al. 2014 [44]	• Considers how shale and other unconventional sources might come on stream, along with how reductions in all (conventional and unconventional) gas costs would affect greenhouse gas emissions in a scenario where there is no climate policy. • This paper does not specifically focus on the role of shale gas, but rather the impact of "more abundant" gas, partly attributed to unconventional sources and partly to falling	• Compares results from a range of integrated assessment models of the future global energy system. • Uses costs from the IIASA Global Energy Assessment (GEA) [45], which for both conventional and unconventional gas are relatively low compared to other sources. • Gas extraction costs are assumed to halve between 2010 and 2050 in the "abundant gas" scenario (described by McJeon et al. as "on the higher end" compared to other studies). • It should be noted that, based upon a review of price history in fossil fuels, McGlade [46]finds no clear evidence for significant long term reduction in fossil fuel extraction costs. For shale gas specifically, McGlade reports a rapid reduction in costs when shale gas was first extracted in the US, which soon plateaued.	• In a "more abundant" gas scenario with no climate policy, gas displaces some coal, and some low carbon energy sources. • Abundant gas has little impact on radiative forcing.

Study	Scope	Methodology/Assumptions	Results/Key Findings
	gas extraction costs.		
Gracceva et al. 2013 [1]	• Considers the economic role of shale gas in the global energy system upto 2040 under “optimistic”, “pessimistic”, and “most likely” shale gas cost and supply scenarios. • No differentiated methane leakage rates from shale / non-shale sources.	• Uses an integrated assessment model (JRC ETSAP-TIAM) of the future energy system. • Uses conventional gas supply curves from the ETSAP-TIAM global energy systems model (a variant of this model forms the core of the AVOID 2 analysis), with costs and resource potentials updated to account for new estimates of conventional gas availability. This tends to make the cheapest conventional gas about twice as expensive as in the variant of the ETSAP-TIAM model used in AVOID 2, whose cheapest reserves are comparable to those in the IIASA GEA. [5] • Shale gas costs are taken from recent regional cost and resource potential estimates [46] – these indicate that the cheapest shale gas is more expensive than the cheapest conventional gas in the JRC ETSAP-TIAM model, but, in the optimistic case and as a result of extraction cost reductions, a little cheaper than some conventional gas used prior to 2040 RC [1].	• There is a notable role for shale gas only when taking the most optimistic resource size assumptions coupled with the most optimistic cost assumptions. • Sensitivity analysis suggests this depends again on the assumptions of (uncertain) shale gas extraction costs.
The IEA’s 2011 “Golden Age of Gas” report [47]	• Estimates remaining recoverable resources and price ranges of conventional and unconventional gas by region.	• Methodology not clear, source quoted as “IEA analysis”	• Extraction costs for shale gas are estimated only in North America, where the range is similar to conventional gas, but marginally above conventional gas prices in Russia and the Middle East.
McGlade and Ekins, 2014 [48]	• Calculates the regional distribution of fossil fuels	• Uses an integrated assessment model of the future energy system (TIAM-UCL).	• 68% of conventional, and 82% of unconventional

[5] We note that this represents an alternative view of conventional gas costs rather than a new benchmark. Supply-cost curves are necessarily subject to assumptions surrounding extraction costs and resource size, which will vary over time and between groups.

Study	Scope	Methodology/Assumptions	Results/Key Findings
	unburnt when limiting global warming to 2°C .	• Uses resource estimates as described in McGlade's [46] doctoral thesis.	gas remains unburnt before 2050. The article does not explicitly specify the proportion of unburnt shale gas.

Figure 3 shows the global supply/cost curves for both conventional gas only, and all gas including shale and other unconventional sources of gas (coal bed methane and tight gas)[6]. This demonstrates the large difference in supply assumptions between a range of reputable sources, although it should be noted that in all cases TRR shale resources are estimated based upon the assessment published by McGlade [21]. In Gracceva's case, cost assumptions are based upon a JRC report by Thonhauser et al., which draws on experience in US wells to estimate costs in Europe (estimation methods for other regions are not clear) [49]. In McGlade's supply curves, regional shale gas extraction costs are based upon estimates for specific wells described in a conference presentation by Medlock [24]. Medlock's presentation does not include a detailed methodology, but does state that "drilling and completion costs [are] estimated using known North American plays, econometrically fit to drilling depth and reservoir pressure". It is not clear whether other geological factors such as field size and clay content, regional expertise, and regulatory frameworks are not taken into account. Stevens [15] notes that these factors could result in significantly higher costs in the UK than the USA, and many of these would also be likely to apply to other regions.

We note that in all cases future cost and resource estimates are necessarily subject to significant uncertainty, although this is often not well quantified, and more central estimates are not necessarily better than more extreme estimates. Step changes in marginal cost curves are often due to assumptions of cost of extraction for different well types, and/or coarse-graining of data in order that its use in complex energy system models is computationally tractable.

[6] In McGlade's analysis, a relatively large uncertainty range is included in both conventional and unconventional resources. In Gracceva et al.'s study, high, medium, and low resource availabilities, and proportions of gas available at different costs are included for shale gas. In both cases, middle ranges are included here.

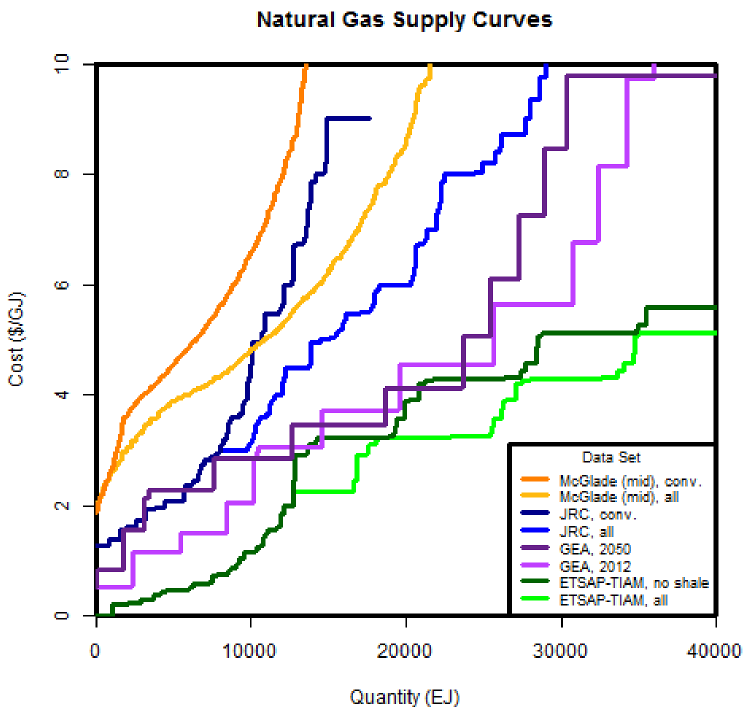

Figure 3: Marginal Cost of Extraction of Gas from a Range of Sources: Including Only Conventional, and Including Conventional and Unconventional Extraction Methods. McGlade 2013 [46]**, JRC 2012** [1]**, GEA 2012** [45]**, ETSAP-TIAM 2005** [50]

Figure 4 shows gas supply curves separated into non-shale (predominantly conventional) and shale resources. Shale gas in both ETSAP and the JRC's marginal cost of extraction curves is divided into three cost bands in each of the fifteen regions considered in the global ETSAP-TIAM energy systems model. From these curves, it is apparent that shale gas extraction is only currently cost competitive with non-shale gas extraction if McGlade's estimates of the costs of non-shale gas extraction (the highest of those considered) are taken alongside ETSAP's estimates (based on McGlade's analysis) of the costs of shale gas extraction (the lowest of those considered). In addition, the shale gas extraction costs in the ETSAP-TIAM model are assumed to fall in line with extraction costs in the least expensive region (identified as Australia) by 2020, where extraction costs are assumed not to change from 2005 levels. As these costs are based on Medlock's [24] 2012 presentation, which appears to be based only on certain geological details of wells, rather than regional experience, it is not clear that this is a reasonable assumption. Looking at the top panel of figure 4, it is apparent that in both the ETSAP-TIAM and JRC analysis, there is around 5,000 EJ of shale gas available at a cost of below approximately $2/GJ. Comparing this with the bottom panel of figure 4 suggests this is below the cheapest shale gas extraction cost, which is just above the $2/GJ level. We note that cost estimates remain in their infancy, and the impact of shale gas on the energy system could be larger or smaller if costs and quantities of supply are found to differ significantly from these estimates.

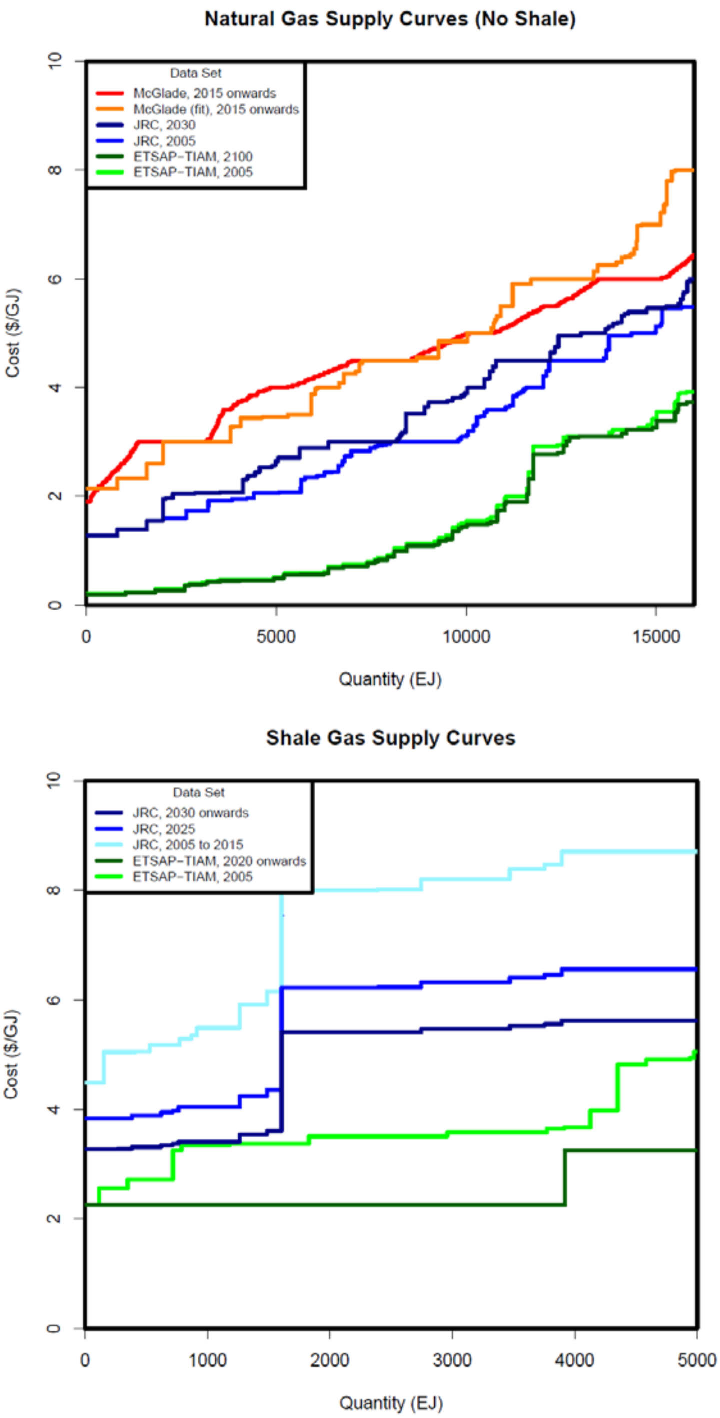

Figure 4: Marginal Cost of Extraction of Gas from a Range of Sources: Non-Shale[7] and Shale[1], [45], [46], [50]

Notes: In the red line in the top panel, McGlade's values are not used directly, as unconventional supply curves are not broken down into shale and non-shale. Instead, McGlade's conventional gas costs are used, alongside gas from unconventional sources other than shale, with costs and quantities as specified by the JRC. In the orange line in the top panel, JRC conventional costs are scaled by a multiplicative factor such that mean gas cost up to 14,000 EJ are identical to those in McGlade's thesis, and non-shale unconventional costs are assumed identical to those used by the JRC. This curve is used in scenario runs in order to provide a reasonable geographical distribution of gas at cost levels similar to those specified by McGlade.

2.5 Analytical gap

These studies leave an analytical gap, as there is yet to be a systematic comparison of shale / non-shale scenarios on reference and 2°C-consistent mitigation scenarios, accounting for methane leakage rate uncertainty. This analysis aims to fill that gap by:

1. Setting out plausible scenarios of cost relativities of shale and conventional gas resources, by reflecting existing uncertainty in the costs of both conventional and shale gas, rather than just uncertainty in shale gas costs. We do this by considering a high, medium and low case for both shale and conventional gas costs;
2. Using an energy system model (TIAM-Grantham) to calculate cost-optimised energy system pathways to 2100, consistent with the 2°C long-term temperature goal, under the cost scenarios outlined above;
3. Exploring the climate change consequences of plausible rates of methane leakage from shale gas, to understand the additional warming that might occur if leakage rates were higher than for non-shale gas.

3 Methods

The analysis of the impact of different assumptions on shale gas resource availability and cost is centred around the use of a global energy systems model, TIAM-Grantham (see Box 1), to explore reference and mitigation scenarios to 2100.

Box 1. TIAM-Grantham

TIAM-Grantham is the Grantham Institute, Imperial College London's version of the ETSAP-TIAM model, which is the global, 15-region incarnation of the TIMES model generator [51], [52], as developed and maintained by the Energy Technology Systems Analysis Programme (ETSAP). The model is a linear programming tool representing in rich resource and technological detail all elements of the reference energy system (RES) for each region represented, mapping energy commodity flows all the way from their extraction and refining to their distribution and end-use. TIAM has the ability to optimise the energy system for given climate constraints through either minimising the total discounted energy system cost over a given time-horizon, or through minimising total producer and consumer welfare when (optionally) accounting for elastic demand responses to energy prices. In the latter case, the model is solved as a partial equilibrium. There is no linkage to a macroeconomic model to observe full equilibrium impacts of changes in energy prices. The model uses exogenous inputs of factors such as GDP, population, household size and sectoral output shares to project future energy service demands across the agricultural, commercial, industrial, residential and transport sectors in each region. Energy system data such as technology costs, resource supply curves and annual resource availability are also input into the model. In solving, the model allows trade in energy commodities between regions. This version of the TIAM model does not represent specific price formation dynamics of different fossil fuels, through for example adding a retail mark-up to resource extraction costs. As such, the focus is on the resource cost of the global energy system in meeting different climate constraints.

The elasticity-enabled TIAM-Grantham integrated assessment model is used to calculate a cost optimised energy system pathway to 2100, first in a reference scenario under which no climate or emissions constraints are applied, and secondly under a global constraint on CO_2

from fossil fuel combustion and industrial processes, of 1,340 $GtCO_2$ over the course of the 21st century, which gives a 50% likelihood of keeping 2100 temperature change below 2°C compared to pre-industrial levels, in line with previous AVOID 2 analysis [53]. The emissions constraint allows for the meeting of the weak end of Cancun pledges to 2020, and then global coordinated mitigation action thereafter, in order to meet the 21st century cumulative CO_2 constraint [53]. It should be noted that – as shown in figure 8 – the resulting CO_2 emissions pathway is likely to be very different to that which would follow Parties' INDC pledges in 2030, which result in emissions levels broadly in line with 2020 levels by that date [54].

All technology and resource costs are taken from ETSAP's 2012 TIAM model version with the exception of gas resources, for which a number of supply curve scenarios for conventional and non-conventional resources are assumed, as outlined in Tables 3.

Table 3: Conventional and unconventional gas cost/supply scenarios

Non-shale Cost Scenario	Description
Low Cost Conventional (LC)	Conventional, tight gas, and coal bed methane cost curves from ETSAP-TIAM 2006 [50] (green lines in Fig 4(top)).
Mid Cost Conventional (MC)	Conventional, tight gas, and coal bed methane cost curves from JRC [1] (blue lines in Fig 4(top)).
High Cost Conventional (HC)	Conventional, tight gas, and coal bed methane cost curves from JRC [1] scaled such that conventional costs are in line with McGlade [46] (orange line in Fig 4(top)).
Low Cost Shale (LS)	Shale cost curves from ETSAP-TIAM 2012 model version, based upon McGlade [46]. Costs are similar to McGlade's thesis up to 2015, with costs in all regions falling to that of lowest cost region in McGlade [46] by 2020 (green lines in Fig 4(bottom)).
Mid Cost Shale (MS)	Shale cost curves from ETSAP-TIAM 2012 model version based upon McGlade [46], adapted such that there is no fall in costs in any region during the model run (light green line in Fig 4(bottom)).
High Cost Shale (HS)	Shale cost curves from JRC [1] mid case (blue lines in Fig 4(bottom)).
No Shale (NS)	No shale gas extraction.
No Unconventional Gas (NU)	No shale gas, tight gas, or coal bed methane extraction.

A central set of reference and mitigation scenarios have been carried out with a central set of combinations of the above scenarios:

- High cost conventional / Low-cost shale gas (denoted "HC_LS");
- Medium-cost conventional / medium cost shale (denoted "MC_MS");
- Low-cost conventional / High-cost shale (denoted "LC_HS");
- Medium-cost conventional / No shale (denoted "MC_NS").

In addition, other combinations of costs of conventional gas and cost and availability of shale gas have been explored, as discussed in the results in section 4.

Activity bounds – which refer to constraints placed upon the rate of extraction of existing gas resources in any given year - are defined based upon those used in the ETSAP-TIAM model at a maximum of 10% extraction of total resource per year for conventional proven reserves, and 5% for unconventional reserves and new discoveries[8].

In order to consider the impact of more limited availability of funding for low carbon electricity technologies when shale gas reserves are exploited, we also calculate pathways to 2100 in which the capital financing rates (essentially the required annual repayment rate of an initial capital loan for the construction of these plants) for low carbon electricity technologies (here taken to include solar, wind, tidal, hydro, geothermal, nuclear power, and biomass for electricity generation) are increased. In addition, we consider energy system pathways in a "dash for shale gas" scenario, in which governments implement policy resulting in rapid extraction of shale gas, despite its being economically suboptimal (for example, in order to ensure energy security, under a mistaken perception that extraction costs are lower than they turn out to be, or as a result of regulatory capture). In this scenario, shale gas extraction rates are imposed in which all shale gas from low and medium cost bands (representing 80% of the estimated shale gas resource) is extracted by 2050 in each region.

Finally, the potential impact of fugitive methane leakage is explicitly considered for those scenarios in which the maximum quantity of shale gas is used, through assuming three illustrative upstream methane leakage rates (of 0.5%, 1% and 5% in excess of methane leakage from conventional sources) which is not mitigated through specific methane mitigation measures. Whilst necessarily arbitrary given uncertainties in leakage at this time, this serves to provide a useful illustration of the potential benefit of robustly monitoring and mitigating any additional methane leakage from shale gas over and above conventional gas sources.

It is important to note that models such as TIAM-Grantham can help give an indication of the most cost-effective way of meeting a set of desired criteria for the energy system, but have a number of limitations:

- These models rely on the availability of data of sufficiently high quality for many aspects of the global energy system, when in reality there are multiple uncertainties around key inputs such as socio-economic trends, technology innovations and fossil fuel resources;
- In practice, global energy systems do not behave cost-optimally, and political, social and behavioural factors are challenging to include within the framework of an energy systems model;
- These models tend to assume perfect foresight of future energy needs, technology costs and fossil fuel supply costs, which will not be the case in practice.

[8] A sensitivity analysis on the MC_NS scenario shows that use of activity bounds based upon the JRC model, in which 1 – 5% of each resource may be extracted per year, dependent on date and resource type, has no material impact on uptake of gas (<1% change in any year) or system cost (<0.01% change in discounted system cost).

4 Results

Key results of modelling studies are presented in this section. It should also be noted that results presented here are the result of a study using a single energy system model. Exact numerical results are likely to differ between models depending upon their implicit assumptions, and more value should be attributed to general trends, directions and orders of magnitude of results than exact numerical values.

4.1 Energy system and mitigation costs

Table 4 shows – for different cost and availability combinations of conventional and shale gas - the present value of the discounted global energy system cost. This is the cost of the whole energy system including all primary energy fuels and energy conversion technologies, spanning extraction to end-use of energy throughout the global economy, as measured by TIAM-Grantham. This present value uses a discount rate of 5% (a standard societal discount rate value used throughout global energy system modelling exercises [53],[55], [56]) and measured over the period 2012-2100. Global energy system costs are shown for different combinations of conventional and shale gas costs, in both the reference scenarios and mitigation scenarios which use these cost combinations. The table also shows the mitigation cost for each conventional/shale gas cost combination, which is the difference between energy system cost in the mitigation and reference cases. Costs are shown in both absolute terms and as a percentage of the present value of future global GDP over the period 2012-2100. In this exercise the TIAM-Grantham model is calibrated to standard growth projections based on the “Shared Socio-Economic Pathways 2” (SSP 2) socio-economic assumptions [57] where global economic output grows from (2005US, PPP) $68 trillion in 2010 to $539 trillion in 2100. A table summarising all scenarios in this report is provided in Annex B.

Table 4: Cumulative discounted cost of the energy system, and cumulative discounted cost of mitigation.

Conventional Gas Cost Scenario	Unconventional Gas Cost Scenario	Shale Gas Extraction Rate	Capital financing Rates for Low Carbon Electricity Technologies	Present value energy system cost over the period 2012-2100*		
				2°C Scenario /$trillion	Reference Scenario /$trillion	Mitigation Cost /$trillion (%GDP)
Low Cost	High	Optimised†	10%	635.2	601.0	34.1 (1.09)
Low Cost	No shale	Optimised	10%	634.4‡	601.3	33.1 (1.05)
Mid Cost	Low	Optimised	10%	640.9	606.4	34.5 (1.10)
Mid Cost	Mid	Optimised	10%	641.8	607.1	34.7 (1.11)
Mid Cost	High	Optimised	10%	642.3	608.0	34.3 (1.09)
Mid Cost	No shale	Optimised	10%	642.9	609.0	33.9 (1.08)
Mid Cost	No unconventional gas	Optimised	10%	644.0	610.8	33.2 (1.06)
High Cost	Low	Optimised	10%	643.2	609.1	34.1 (1.09)
High Cost	No shale	Optimised	10%	645.7	612.7	33.0 (1.05)

Notes: *Discount rate 5% used to calculate cumulative discounted cost. †Here "optimised" means that extraction of shale gas occurs when it is cost-minimising for the energy system as a whole, with no specific additional constraints. All costs in 2005 $US. ‡ The slightly higher 2°C scenario cost for LCHS than LCNS is likely to be the result of shale gas usage in the period up to 2020 (during which period the model is optimising towards meeting weak Cancun pledges) which turns out to be suboptimal to meet a 2°C target up to 2100.

As shown in Table 4, the 2°C-consistent energy system cost in the mitigation scenarios is similar in all cases, indicating that differences in gas availability are not likely to have a large impact on the feasibility and cost of meeting a 2°C target. The 1.39% increase in energy system cost between LC_NS and HC_LS scenarios is relatively large compared to the 0.31% increase between MC_NS and MC_LS scenarios. This indicates that system cost is more sensitive to conventional gas cost sensitivities rather than shale gas cost sensitivities. In the LC_HS scenario, significant quantities of conventional gas are available at costs significantly below that of shale gas costs in most regions, leading to minimal shale gas extraction in the model, whilst even in the HC_LS scenario, lowest shale gas costs are similar to conventional gas costs, and the vast majority of gas is extracted from conventional sources up to 2100.

4.2 Primary energy share of natural gas

Figure 5 shows the proportion of total primary energy supplied by all natural gas and by shale gas alone in the LC_HS, MC_MS, HC_LS, and MC_NS scenarios in 2°C consistent energy systems (results from reference scenarios with no climate constraint are provided in Annex C, alongside the temporal evolution of total energy demand, and details of the energy supply resource mix). In all cases, all natural gas (i.e. conventional and shale gas in combination) makes a significant contribution to total primary energy supply in the period 2020-2040, with the natural gas share of total primary energy peaking in 2030 and then diminishing rapidly thereafter, as energy supply from fossil fuel becomes substituted by an increasing penetration of renewable energy sources. In all scenarios except HC_LS, the share of shale gas in global primary energy is below 6% before 2040, whilst natural gas from all sources accounts for more than 20% of primary energy during this period. Figure 5 also illustrates that the most influential factor on global primary natural gas demand in the mitigation scenarios is the cost of conventional gas, since it is only the scenario with the lower end of the cost range for conventional gas (LC_HS) that has significantly higher gas demand than the other scenarios.

On the demand side, when low cost shale gas is added to a scenario with high conventional costs (HCLS vs. HCNS), gas extraction increases by 14% in the peak year (2030) reducing coal extraction by 26%. Switching of demand from gas to coal predominantly occurs in the industrial sector, but the introduction of shale gas is also associated with small shifts from coal to gas in electricity generation, oil to gas in road transport, and electricity to gas in the residential sector. A more detailed breakdown of the energy mix in 2030 (the period of peak gas usage in our modelled results), and a sectorial breakdown of the demand side indicating where additional gas is used when shale gas is added to the energy system, and which fuels are displaced, is provided in Annex D.

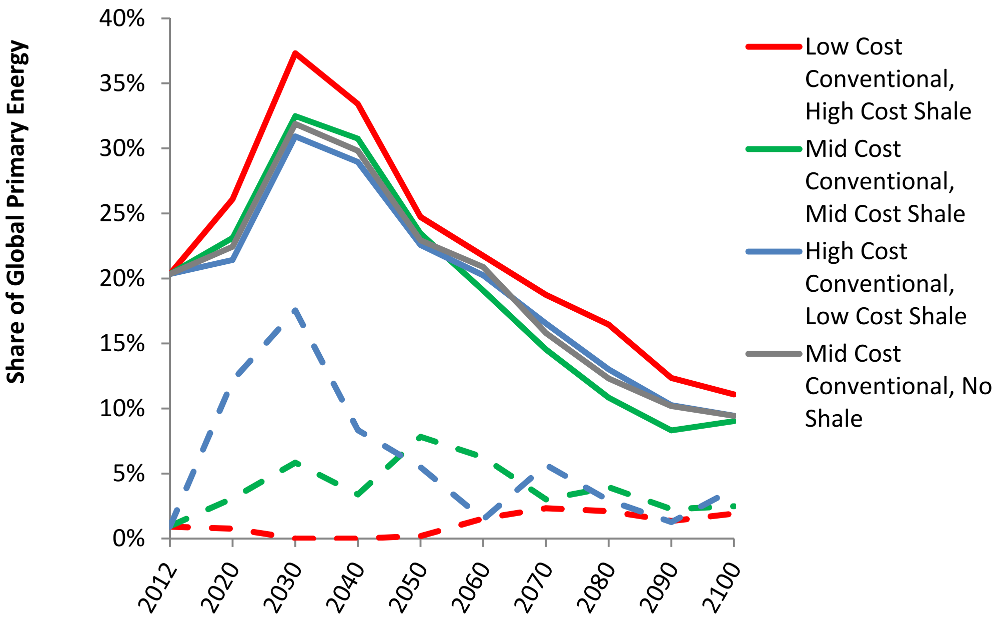

Figure 5: Share of global primary energy supplied by (solid lines) all natural gas, and (dashed lines) shale gas in 2°C consistent energy systems in a range of cost scenarios for conventional and shale gas.

In the HC_LS, scenario, 13% of total primary energy is provided by shale gas in the period 2012 - 2040. In the MC_MS and LC_HS scenarios respectively, 3.3% and 0.4% of total primary energy is supplied by shale gas in the same period. In no scenario or regions is there any extraction of shale gas from any but the least expensive cost bands prior to 2040.In the LC_HS and MC_MS scenarios, there is no significant extraction of shale from any but the least expensive bands prior to 2060. It should be noted that, in practice, it may not be straightforward to identify whether a field is likely to be among the most cost-effective prior to significant investment in extraction in that field. Therefore, potential economic benefits of shale gas extraction even from these sources may be challenging to realise. In the period 2016 - 2040, 4,600 – 5,500 EJ of natural gas is extracted between scenarios, equivalent to 60 – 72% of proven global reserves, as estimated by the Energy Information Administration in 2014 [58], and 65 – 82% of the range presented by the GEA in 2012 [45].

In the MC_NS scenario, 4% less natural gas is used in the period 2012 – 2100 when compared to the MC_MS scenario, but more gas is extracted from non-shale sources. Conventional gas increases its share in total natural gas supply from 57% to 69%, tight gas from 6% to 9%, and coal bed methane from 16% to 21%. We calculate an additional MC scenario with no unconventional gas extraction (i.e. no shale gas, coal bed methane, or tight gas extraction). In this scenario, energy system costs are higher by 0.07% of GDP, and total gas extraction lower by 18%, when compared to the MC_MS scenario.

4.3 Impacts of CCS on gas share of global primary energy

Figure 6 shows that the dependence of the future energy system on natural gas as a whole, and shale gas in particular, itself depends on whether carbon capture and storage technology is available. In the mitigation scenarios without CCS, there is a 38-47% lower demand for total natural gas compared to the mitigation scenarios with CCS. Shale gas demand is reduced by 67% where its cost is highest (the LC_HS scenario) and by 20-26% for the other mitigation scenarios. These scenarios are purely illustrative, since without CCS, the TIAM-Grantham model is unable to meet future energy demand and stay within the 2°C consistent CO_2 budget over the 21st century, without recourse to a theoretical backstop technology which mitigates CO_2 at a cost of 2005US$10,000/t$CO_2$. These scenarios are therefore deemed to indicate economic and technical infeasibility of meeting the 2°C goal.

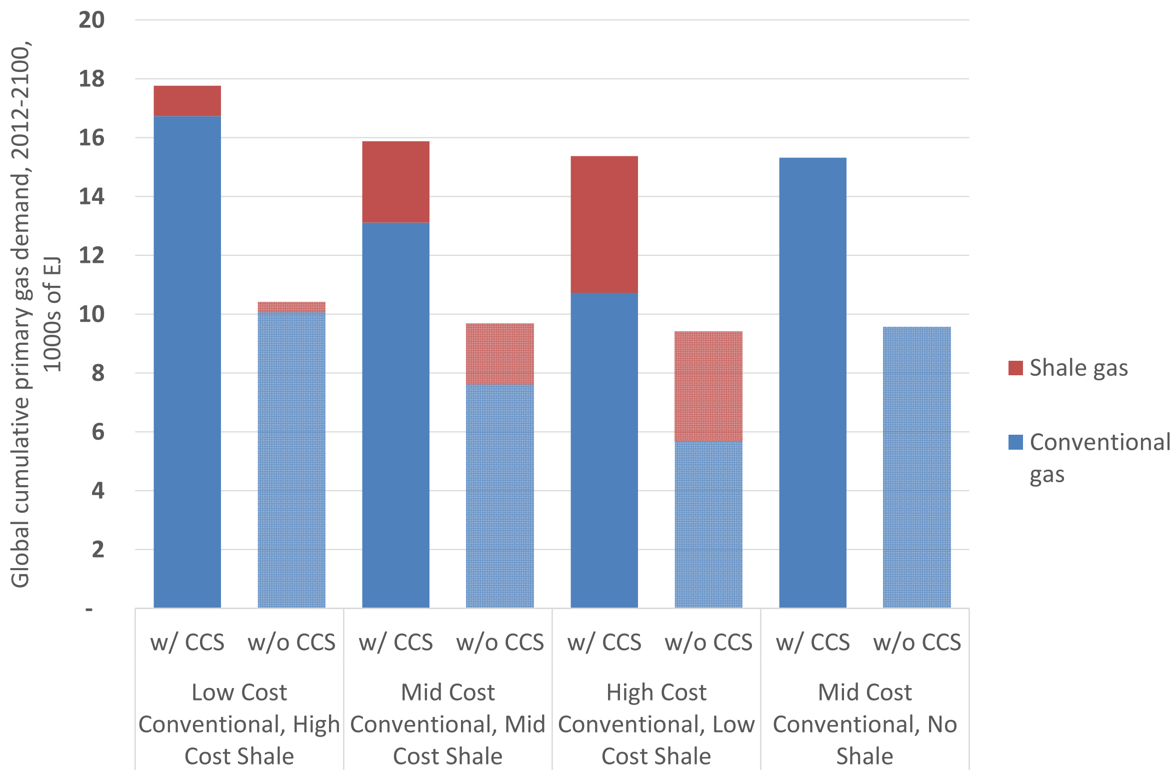

Figure 6: Global cumulative primary demand for natural gas over the period 2012-2100, in 2°C mitigation scenarios with and without availability of CCS

4.4 Region-specific results

Only in the HC_LS scenario is there any extraction of shale gas outside of the USA prior to 2030, and in the LS_HS scenario, there is no extraction of shale gas outside of the USA until 2050. This is in part due to relatively high costs of shale gas extraction in most regions outside of the USA and Canada, and in part due to trade links between countries. Most of the least expensive conventional gas reserves are located in the former Soviet Union and the Middle East (In the ETSAP-TIAM data set, 66% of reserves available below $2/GJ are in these two regions, and only 11% in the Americas), and pipeline infrastructure allows the export of significant quantities of natural gas from these countries to Eastern and Western Europe, China, and India. These resources are only available to the Americas via relatively expensive LNG transport.

4.5 Impact on development of other low-carbon technologies

In order to consider the possible impact of more limited availability of finances for low carbon electricity technologies on the cost of a climate constrained energy system, we calculate energy system pathways under scenarios in which capital financing rates for low-carbon electricity technologies are increased by 1% (compared to the standard 10% cost of capital value used for these technologies), and also for scenarios in which these capital financing rates are doubled. These are arbitrary choices used purely to illustrate the potential sensitivity of the energy system cost to any increase in financing rates for low-carbon electricity technologies, which could occur as a result of either competing capital demands for shale gas, or uncertainty surrounding the level of policy support for low-carbon electricity technologies. These technologies are: solar photovoltaic and concentrating solar power; onshore and offshore wind; geothermal; hydro; tidal and marine; biomass; and nuclear. Energy system costs under these scenarios are presented in Table 5.

Table 5: Cumulative discounted cost of the energy system, and cumulative discounted cost of mitigation in high financing rate scenarios.

Conventional Gas Cost Scenario	Unconventional Gas Cost Scenario	Shale Gas Extraction Rate	Capital financing Rates for Low Carbon Electricity Technologies	Present value energy system cost over the period 2012-2100*		
				2°C Scenario /$trillion	Reference Scenario[9]/$trillion	Mitigation Cost /$trillion (%GDP)
Low Cost	High Cost	Optimised	11%	636.7	601.0	35.6 (1.13)
Mid Cost	Mid Cost	Optimised	11%	643.0	607.1	35.9 (1.14)
High Cost	Low Cost	Optimised	11%	644.2	609.1	35.1 (1.12)
Low Cost	High Cost	Optimised	20%	652.8	601.0	51.7 (1.65)
Mid Cost	Mid Cost	Optimised	20%	659.5	607.1	52.5 (1.67)
High Cost	Low Cost	Optimised	20%	660.9	609.1	51.8 (1.65)

Table 5 shows that – when comparing the LC_HS, MC_MS and HC_LS scenarios with and without the increased capital financing rates for low-carbon electricity technologies – a 1%

[9] Standard 10% financing rates are retained in the reference scenario.

increase in capital financing rates increases mitigation costs by (US2005)$1.0-1.5trillion over the period 2012-2100 – this means mitigation costs are 3-4% higher as a result of these increased financing rates. An extreme case in which capital finance rates double leads to mitigation costs which are 51-52% higher than the standard financing rate cases. There is as yet no substantive evidence around the impact of shale gas investment on capital availability (and hence the cost of capital) for low-carbon electricity technologies, so these results serve only to illustrate the potential mitigation cost impact of different capital financing rate increases, rather than the direct mitigation cost impact of investment in shale gas per se.

4.6 Impact of a “dash for shale gas”

In order to consider the possible impact of a “dash for shale gas” on the cost of a climate constrained energy system, we calculate energy system pathways under scenarios in which an extraction profile of shale gas is imposed, such that all shale gas from lower and medium cost sources (representing 80% of the estimated total shale gas resource) is extracted by 2050. Figure 7 shows the proportion of total primary energy supplied by all natural gas and by shale gas alone in the LC_HS, MC_MS, HC_LS scenarios under such a constraint.

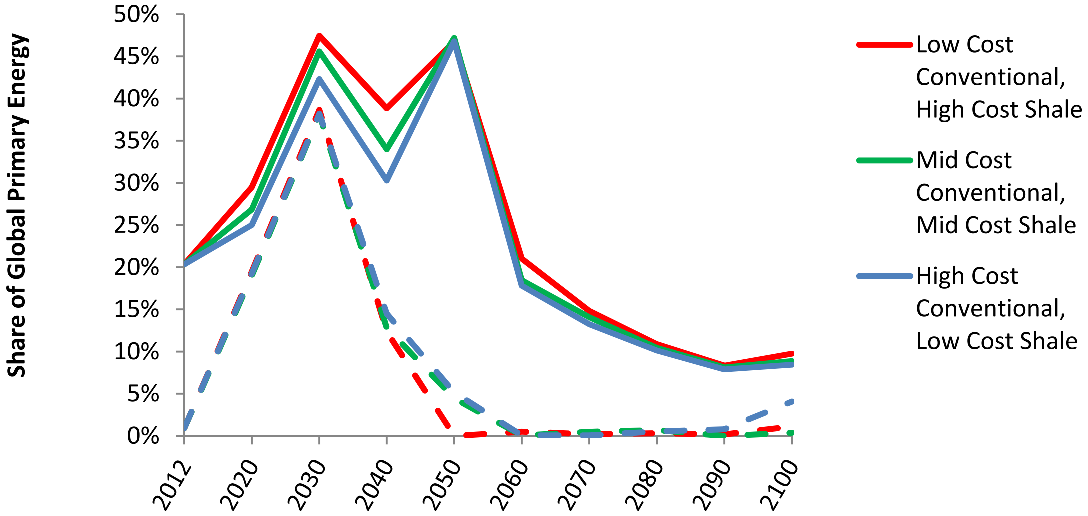

Figure 7: Share of global primary energy supplied by (solid lines) all natural gas, and (dashed lines) shale gas in a range of cost scenarios for conventional and shale gas under a “dash for shale” scenario.

Energy system costs under these scenarios are presented in Table 6.

Table 6: Cumulative discounted cost of the energy system, and cumulative discounted cost of mitigation in 'dash for shale gas' scenarios.

Conventional Gas Cost Scenario	Unconventional Gas Cost Scenario	Shale Gas Extraction Rate	Capital financing Rates for Low Carbon Electricity Technologies	Present value energy system cost over the period 2012-2100*		
				2°C Scenario /$trillion	Reference Scenario /$trillion	Mitigation Cost /$trillion (%GDP)
Low Cost	High Cost	Dash	10%	646.9	601.0	45.9 (1.46)
Mid Cost	Mid Cost	Dash	10%	649.0	607.1	41.9 (1.33)
High Cost	Low Cost	Dash	10%	650.6	609.1	41.6 (1.32)
Low Cost	High Cost	Dash	11%	648.8	601.0	47.8 (1.52)
Mid Cost	Mid Cost	Dash	11%	651.0	607.1	43.9 (1.40)
High Cost	Low Cost	Dash	11%	652.7	609.1	43.6 (1.39)
Low Cost	High Cost	Dash	20%	664.9	601.0	63.9 (2.03)
Mid Cost	Mid Cost	Dash	20%	667.5	607.1	60.5 (1.92)
High Cost	Low Cost	Dash	20%	669.4	609.1	60.3 (1.92)

This analysis suggests that a dash for shale gas could significantly increase mitigation cost, and the cost of the energy system under a climate constrained scenario. With no increase in capital financing rates for low carbon electricity technologies, a dash for shale gas leads to an increase in global mitigation cost to 1.3 – 1.5% of GDP depending on cost and availability of conventional and shale gas, relative to 1.1% of GDP with no dash for gas (a mitigation cost increase of 21-35%). When combined with an increase in capital financing rates to 11% or 20%, mitigation costs rise to 1.4 – 1.5% and 1.9 – 2.0% of GDP respectively. This follows from the analysis of shale and conventional gas cost relativities as presented in section 2, whereby in all scenarios there is significant conventional gas available at a cost below that of shale gas, indicating that a forced extraction of shale gas is unlikely to be cost-optimal.

4.7 Rates of decarbonisation

Figure 8 shows that the exploitation of shale gas reserves has very little impact on the cost-optimal rate of decarbonisation of the global energy system throughout the 21st century in the 2°C mitigation scenarios. The "dash for shale" scenario has the most significantly different decarbonisation pattern in the first half of the 21st century, with an average annual CO_2 reduction rate of 4.6% in the decade 2020-2030 (compared to 4.9-5.0% for all of the other scenarios shown), and 4.1% in the decade 2030-2040 (compared to 3.4-3.5% for the other scenarios). This changed profile of emissions reductions, with less effort in the next decade and more in the one after, is consistent with forcing relatively higher carbon shale gas into the energy system initially. We do not however deem this relatively small difference between the "dash for shale" and other scenarios to be sufficient to draw specific conclusions about the exploitation of shale gas on the feasibility of mitigation using this "rates of decarbonisation" measure. This is particularly so given that the near-term rates of decarbonisation required in all scenarios, at around 5% per year in the decade 2020-2030, are unprecedented at a global level, and therefore all likely to be challenging to achieve in practice[10].

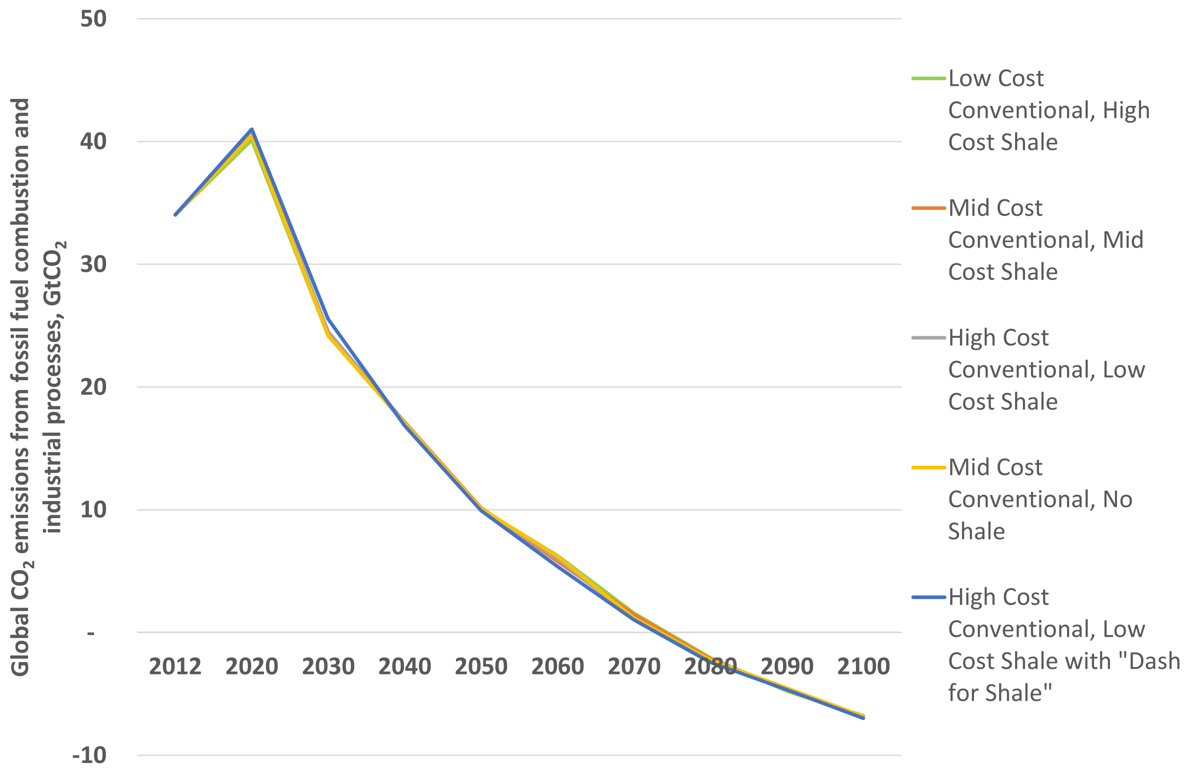

Figure 8: Global fossil fuel and industrial CO_2 emissions in a range of 2°C scenarios

4.8 Methane emissions

In this section, we consider the implications of a scenario in which policy has been enacted with a 2°C target, under the assumption that leakage rates are identical to that of conventional gas. We then consider the temperature implications if methane leakage rates turn out to be higher (as a result of ineffective regulation and policy, or unexpected challenges in monitoring and emissions reduction). This temperature calculation is based on analysis by Met Office Hadley Centre as described in AVOID 2 report WPC2a [53] and WPC2b [59].

Figure 9 shows that – for the High Cost Conventional, Low Cost Shale (HC_LS) scenario, there would be a relatively small additional global warming to 2100 if the additional leakage rate of fugitive methane from shale gas extraction is 1% or less. However, a leakage rate of 5% above conventional gas would lead to a notable impact, with median global temperature exceeding 2°C by 2065, and reaching 2.06°C in 2100, 0.08°C above the median temperature change of 1.98°C in the scenario where no fugitive methane leakage is assumed. This latter assumption of no leakage is consistent with leakage from conventional gas in 2°C mitigation scenarios, where upstream fugitive methane is largely eliminated by increased flaring, well inspections and other mitigation measures[11].

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[10] It should be noted, however, that higher decarbonisation rates have been achieved at an individual country level. A detailed overview of historical and possible future decarbonisation rates is given in reference [73] and associated supporting information.

[11] Note that we refer only to additional fugitive emissions over and above levels associated with conventional natural gas extraction and supply.

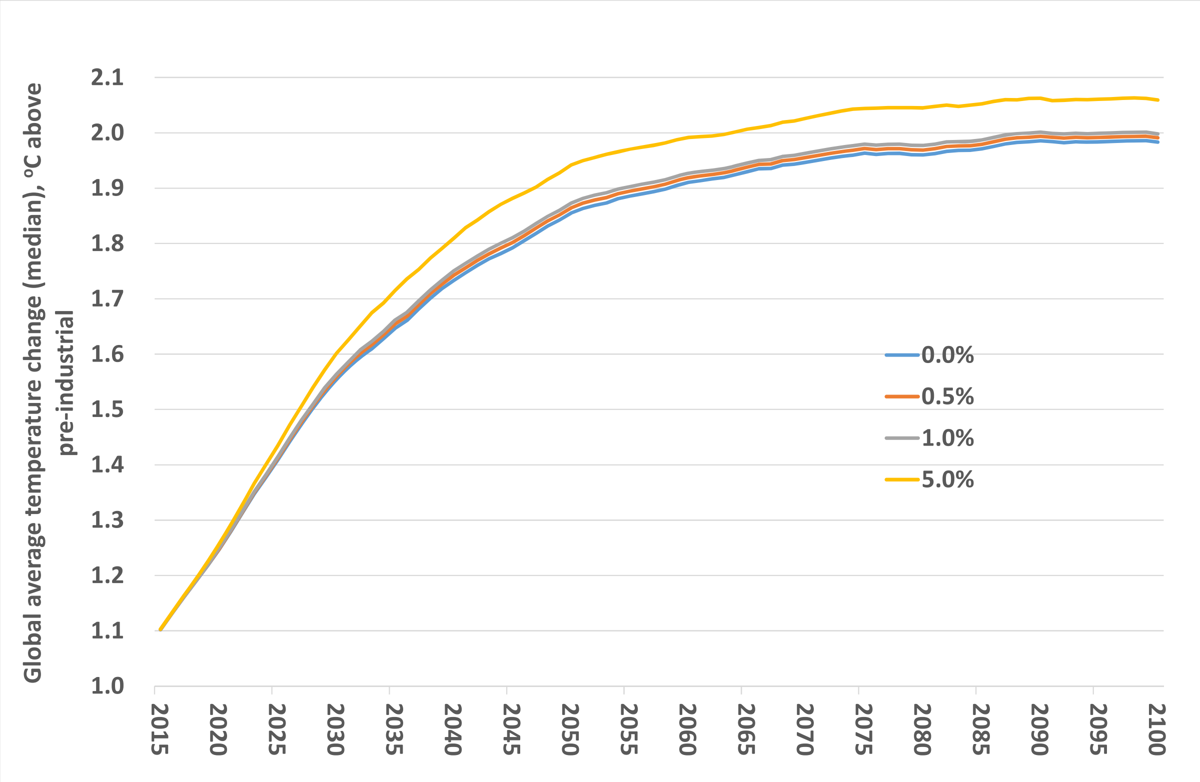


Figure 9: Median temperature change with different assumptions on unmitigated fugitive methane leakage from shale wells, High Cost Conventional, Low Cost Shale (HC_LS) scenario

If there were a dash for shale gas, then as shown in Figure 10, a fugitive methane leakage rate of 5% would mean that the 2°C threshold would be exceeded (with 50% likelihood) in 2050. This could be an important factor in keeping global average temperature change “well below 2°C” as stated in the UNFCCC Paris Agreement [60].This study does not assess the costs of mitigation of this additional methane, since at the current time the measures to accurately monitor and mitigate fugitive methane emissions are not in place, as discussed in section 2.

Whilst the highest leakage rate scenarios may not occur, should sufficient mitigation measures be put in place, there is not yet sufficient detail available in plans for emission reductions (particularly surrounding well-monitoring when using large numbers of wells, as typically required for shale gas extraction), so whilst our higher leakage rate scenario is not a forecast of the probable future, it serves as a useful illustration of the degree to which inadequate control or mitigation of fugitive methane is important to any large-scale extraction of shale gas.

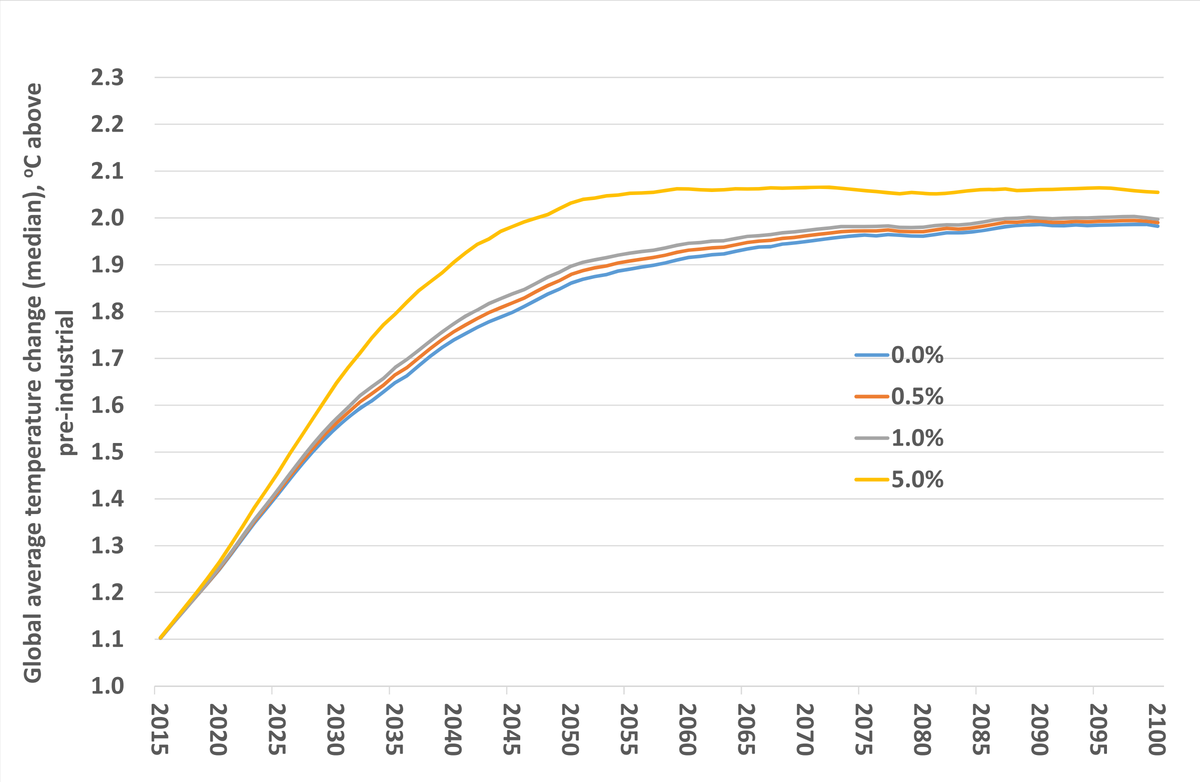


Figure 10: Median temperature change with different assumptions on unmitigated fugitive methane leakage from shale wells, High Cost Conventional, Low Cost Shale (HC_LS) with Dash for Shale Gas scenario

5 Discussion and conclusions

Considerable uncertainty around shale and conventional gas resource availability and extraction costs suggests that a scenario analysis is useful in understanding the potential range of future impacts of shale gas extraction on a range of factors including global energy system costs, rates of decarbonisation and the demand for natural gas, in a global energy system which transitions to low-carbon in order to limit global warming to below 2°C in 2100.

Three primary cost combination scenarios of shale and conventional gas resources are explored in this study: high cost conventional, low cost shale (HC_LS); medium cost conventional, medium cost shale (MC_MS); low cost conventional, high cost shale (LC_HS). These scenarios all show that there is a significant near-term - but diminishing long-term - role for natural gas as a whole in a low-carbon energy system transition. When the lowest cost shale gas supply estimates are combined with the highest cost conventional gas estimates (the HC_LS scenario), shale gas alone would make up more than 10% of global primary energy supply in the period 2020-2040, peaking at 18% in 2030, in a cost-minimising 2°C consistent energy system transition pathway. However, in the other shale gas cost scenarios, shale gas makes up 6% or less of global primary energy before 2040. In other words, natural gas as a whole could be an important bridge to a low-carbon future over the next two decades, but shale gas (at least according to the resource cost and availability data used in this study) would only constitute a large share of that gas supply if its cost is at the lower end of estimates and conventional gas costs are at the higher end. Moreover, if carbon capture and storage technology is not available in 2°C scenarios, the role of natural gas as a whole and shale gas in particular would be significantly reduced.

Of all scenarios explored, the 2°C scenario with the lowest energy system cost is that which has low conventional gas cost assumptions, indicating that the future cost of conventional gas is more influential on future energy system costs than the cost of shale gas. The current evidence does not suggest that – on a global level – shale gas would significantly reduce the cost of achieving the 2°C goal. This is before accounting for any impact that shale gas investment could have on investment in low-carbon electricity technologies, where analysis suggests that any capital constraints – leading to a 1% increase in cost of capital for these electricity technologies – would increase mitigation costs by 3-4% across the conventional/shale gas cost scenarios explored. If there is a concerted effort to exploit global shale gas reserves in spite of these resources not necessarily being the least-cost gas resources, then the analysis presented here suggests this could increase global mitigation costs towards a 2°C goal by 21-35%.

There is little discernible impact of shale gas exploitation on global CO_2 emissions reduction rates, which are comparable across scenarios. Finally, although there is considerable uncertainty over fugitive methane leakage rates from shale wells, the analysis presented here suggests there could be additional global warming in 2100 if the average fugitive methane leakage from shale gas is higher than that of conventional gas sources, and is not mitigated – so it is clearly important that appropriate monitoring and mitigation measures are put in place.

In summary, this analysis suggests that global shale gas availability would not make a significant (positive or negative) impact on the cost and feasibility of an energy system transition consistent with the 2°C goal, nor significantly affect the cost-optimal decarbonisation pathway globally. However, unsurprisingly, any forced exploitation of shale gas even where uneconomic compared to conventional sources of gas could lead to higher global mitigation costs overall. These findings should be taken in the context of the uncertainties already outlined, whilst also noting that they derive from one global energy systems model only.

Annex A – Sources on fugitive emissions

Table A1: A summary of literature on methane emissions associated with shale gas extraction

Study	Methane Leakage Rate	Method/description	Caveats/Criticisms
Sustainable Gas Institute, (Balcombe et al. 2015) [61]	**Whole Supply Chain:** up to ~4.7%, central estimate ~1.5% **Extraction:** 0.2 – 1.8%	Critical Review. The SGI report notes the existence a number of "super-emitters", defined as "an emission source that leaks far in excess of the average", which are not included in best practice emission ranges. The authors state an expectation that these could be largely eliminated if more stringent procedures were applied, but note technical uncertainty in some areas (liquids unloading, in particular), and challenges in monitoring wells which are yet to be resolved.	Assuming best practice, excluding super emitters
Howarth, Santoro, & Ingraffea, 2011 [62]	**Whole Supply Chain:** 3.6 – 7.9% **Extraction:** 2.2 – 4.3%	Bottom-up summation of expected emissions during extraction stages, literature review on supply chain emissions. Significant extraction emissions, chiefly occurring during well-completion and routine venting	Assumptions surrounding flow rate during completions, and venting rather than flaring have been criticised [63]
Allen et al., 2013 [39].	**Extraction:** ~0.42% (all well types – shale and non-shale)	Bottom-up summation of emissions from known sources, as measured at selected onshore natural gas sites provided by participating utility companies in the USA.	Reports by Howard et al. [37], [38]. state that a sensor failure is likely to have led to significant underestimates in fugitive emissions in Allen's study Allen [40] has responded to some of these concerns. However, this remains an area of ongoing debate and analysis.
Stephenson et al., 2011 [64]	**Extraction:** ~0.6%	Bottom-up summation of emissions from known sources,	Assuming reduced emission completions and flaring rather than venting.
O'Sullivan & Paltsev, 2012 [65]	**Extraction:** 0.39 - 0.99%	Bottom-up summation of emissions from known sources,	Assuming reduced emission completions and flaring rather than venting.
Zavala-Araiza et al., 2016 [66]	**Extraction:** 1.2 – 2.7%, central estimate 1.8%	Bottom-up summation of emissions from known sources and top-down atmospheric measurements, each over several days, combined with spatially explicit list of all oil and gas infrastructure in the region created by combining all available data. Ethane also measured to distinguish bionic from fossil sources.	Relies on accurate bottom-up information, and source apportionment challenging, but agreement bottom-up and top-down measurements is good.
Karion et al., 2013 [67]	**Extraction:** 8.9 +- 2.7% (Utah)	Top-down atmospheric measurement	Difficulty of source apportionment represents a significant challenge
Caulton et al., 2014 [68]	**Extraction:** 3 – 17% (Marcellus formation)	Top-down atmospheric measurement	Difficulty of source apportionment represents a significant challenge
Peischl et al., 2015 [69]	**Extraction:** 1.0–2.1% (Haynesville), 1.0 – 2.8% (Fayetteville), 0.18 – 0.41% and 6 - 20%[12] (sites in Western Arkoma)	Top-down atmospheric measurement	Difficulty of source apportionment represents a significant challenge
Schneising, et al. 2014 [70]	**Extraction:** 10.1 +- 7.3% (Bakken) 9.1 +- 6.2% (Eagle Ford)	Satellite measurements taken prior to (2006 - 2008), and during (2009 - 2011), the US shale gas (and oil) boom	Difficulty of source apportionment represents a significant challenge

[12] The authors describe the last of as "probably an overestimate", but note that it suggests significant emissions from inactive wells.

AVOID 2

Annex B – Energy system cost in all scenarios

Table B1: Cumulative discounted cost of the energy system, and cumulative discounted cost of mitigation.

Conventional Gas Cost Scenario	Unconventional Gas Cost Scenario	Shale Gas Extraction Rate	Capital financing Rates for Low Carbon Electricity Technologies	Present value energy system cost over the period 2012-2100*		
				2°C Scenario /$trillion	Reference Scenario /$trillion	Mitigation Cost /$trillion (%GDP)
LC	HS	Optimised†	10%	635.2	601.0	34.1 (1.09)
LC	NS	Optimised	10%	634.4‡	601.3	33.1 (1.05)
MC	LS	Optimised	10%	640.9	606.4	34.5 (1.10)
MC	MS	Optimised	10%	641.8	607.1	34.7 (1.11)
MC	HS	Optimised	10%	642.3	608.0	34.3 (1.09)
MC	NS	Optimised	10%	642.9	609.0	33.9 (1.08)
MC	NU	Optimised	10%	644.0	610.8	33.2 (1.06)
HC	LS	Optimised	10%	643.2	609.1	34.1 (1.09)
HC	NS	Optimised	10%	645.7	612.7	33 (1.05)
High Capital financing Scenarios						
LC	HS	Optimised	11%	636.7	601.0	35.6 (1.13)
MC	MS	Optimised	11%	643.0	607.1	35.9 (1.14)
HC	LS	Optimised	11%	644.2	609.1	35.1 (1.12)
LC	HS	Optimised	20%	652.8	601.0	51.7 (1.65)
MC	MS	Optimised	20%	659.5	607.1	52.5 (1.67)
HC	LS	Optimised	20%	660.9	609.1	51.8 (1.65)
Dash for Shale Scenarios						
LC	HS	Forced	10%	646.9	601.0	45.9 (1.46)
MC	MS	Forced	10%	649.0	607.1	41.9 (1.33)
HC	LS	Forced	10%	650.6	609.1	41.6 (1.32)
LC	HS	Forced	11%	648.8	601.0	47.8 (1.52)
MC	MS	Forced	11%	651.0	607.1	43.9 (1.40)
HC	LS	Forced	11%	652.7	609.1	43.6 (1.39)
LC	HS	Forced	20%	664.9	601.0	63.9 (2.03)
MC	MS	Forced	20%	667.5	607.1	60.5 (1.92)
HC	LS	Forced	20%	669.4	609.1	60.3 (1.92)

Notes: *Discount rate 5% used to calculate cumulative discounted cost. †Here "optimised" means that extraction of shale gas occurs when it is cost-minimising for the energy system as a whole, with no specific additional constraints. All costs in 2005 $US. ‡ The slightly higher 2°C scenario cost for LC_HS than LC_NS is likely to be the result of shale gas usage in the period up to 2020 (during which period the model is optimising towards meeting weak Cancun pledges) which turns out to be suboptimal to meet a 2°C target up to 2100.

Annex C – Reference Scenarios, Net Energy Consumption, and Energy Source Mix

Share of conventional and shale gas in in energy supply in a range of cost scenarios with no mitigation is presented in Figure C1. Absolute energy demand growth, and the evolution of the energy supply mix upto 2100, in 2°C consistent and reference scenarios are presented in Figures C2 and C3 respectively. Energy demand growth and resource mix evolution is broadly in line with previous TIAM-Grantham runs included in previous AVOID2 analysis [53].

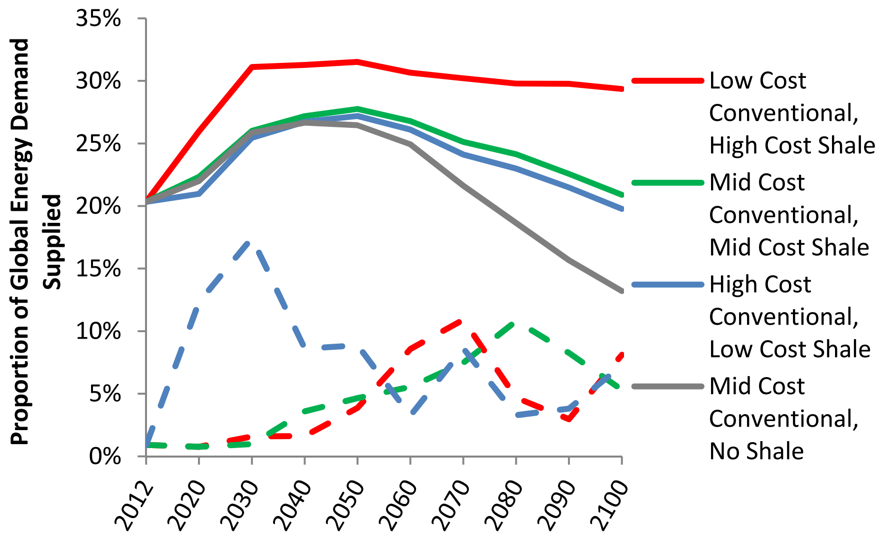


Figure C1: Share of global primary energy supplied by (solid lines) all natural gas, and (dashed lines) shale gas in reference energy systems with no mitigation action in a range of cost scenarios for conventional and shale gas.

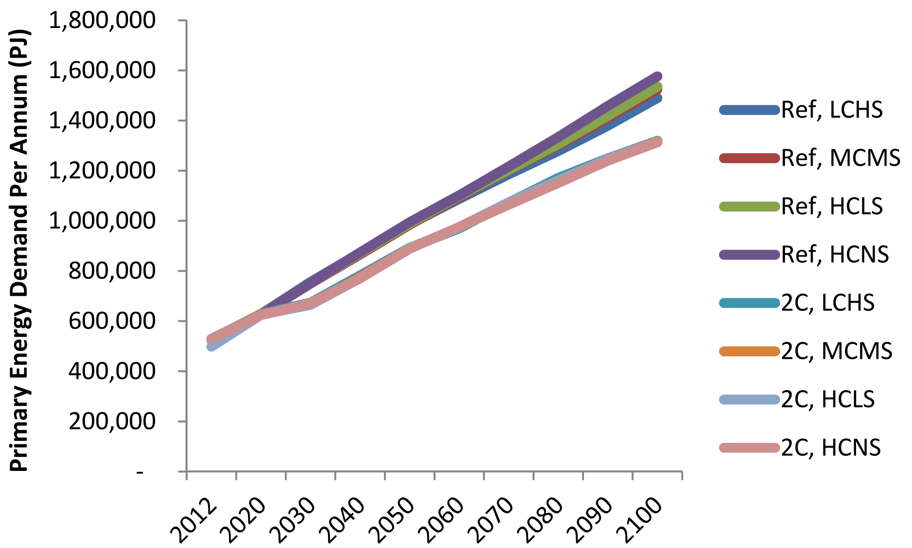


Figure C2: Total primary energy demand per annum in 2°C and reference scenarios with no mitigation action for a range of cost scenarios for conventional and shale gas.

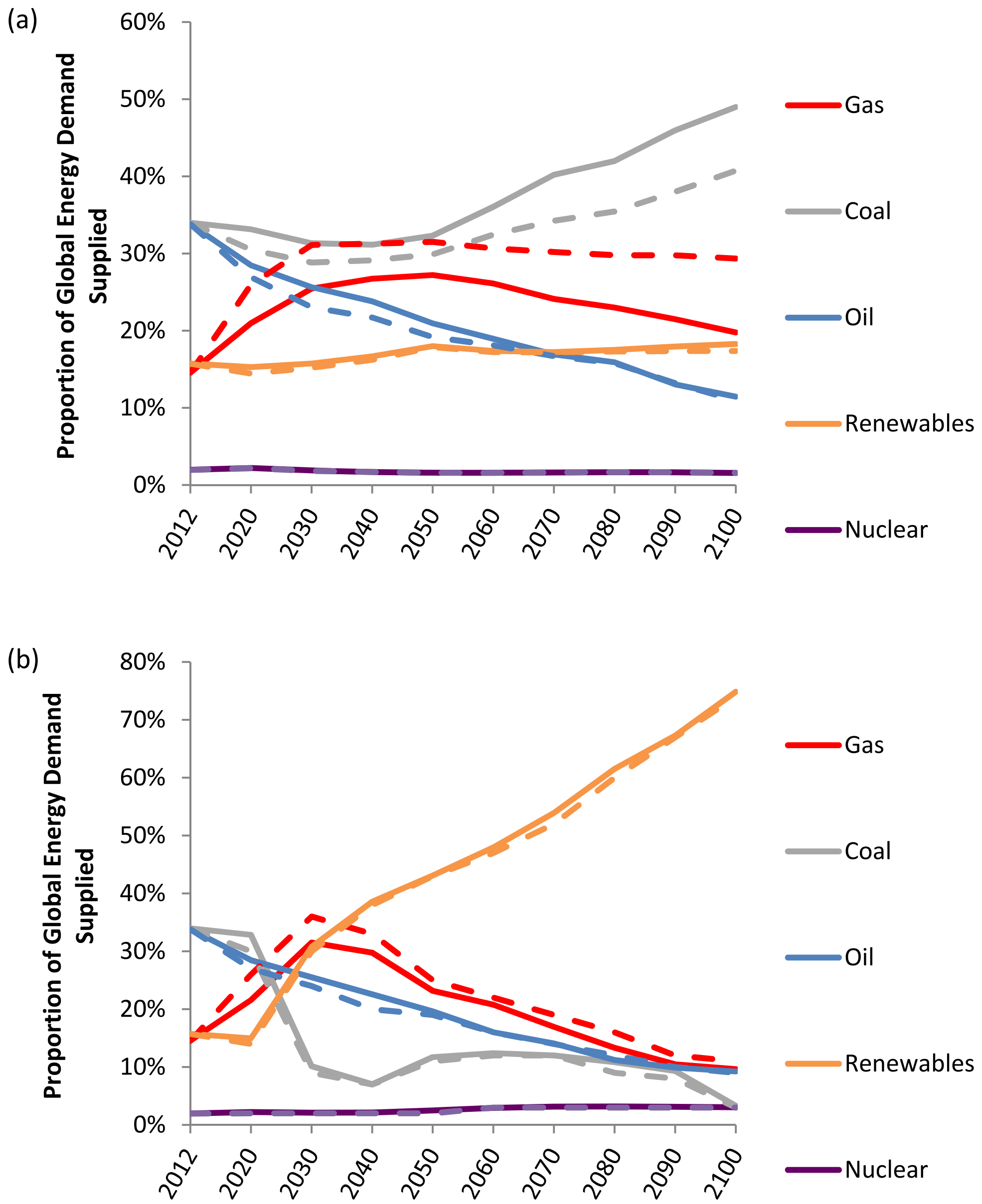


Figure C3: Energy supply from a range of sources over time in (a) a reference scenario with no mitigation action, and (b) a 2°C-consistent scenario. Solid and dashed lines are results from model runs using the HCLS and LCHS cost scenarios, respectively.

Annex D – Sectorial Results

In this annex, we examine global energy supply and sectorial demand mix in a range of 2C scenarios in 2030, the period of peak natural gas usage in our model runs.

Figure D1 shows the global energy supply mix in 2030. Total primary energy production in this year is similar in all scenarios except for one in which there is a dash for shale gas, where total primary energy production is 21% higher. In the HCLS scenario relative to the HCNS scenario, gas production is 14% higher (equivalent to 3.7% of world energy production), mostly displacing coal production, which is 26% lower (equivalent to 3.5% of world energy production). The remaining difference in supply is chiefly compensated for by a 2.3% decrease in both oil and biomass production. Energy production from nuclear, hydro, wind, and geothermal each reduce by less than 2% with the reduction of shale gas. Energy production from solar accounts for 0.3% of global energy production in HCNS in 2030, and falls by 7% in HCLS. This fall is more significant in 2050, in which year solar accounts for 2% of global energy demand in HCNS, and falls by 53% in HCLS.

In LCHS, significantly more gas is available at a lower extraction cost, and the balance of displaced fuels differs significantly from HCLS. In the LCHS scenario relative to the HCNS scenario, gas production is 31% higher (equivalent to 8.5% of world energy production), whilst coal production falls by 36% (equivalent to 4.9% of world energy production). A 9% decline in oil production (equivalent to 2.3% of world energy production), combined with a 3% decline in biomass production (equivalent to 0.6% of world energy production) are also associated with the increase in natural gas production between these scenarios. Relative to HCNS, decline in solar power is more significant in LCHS than HCLS, falling by 69% by 2030, and 63% by 2050.

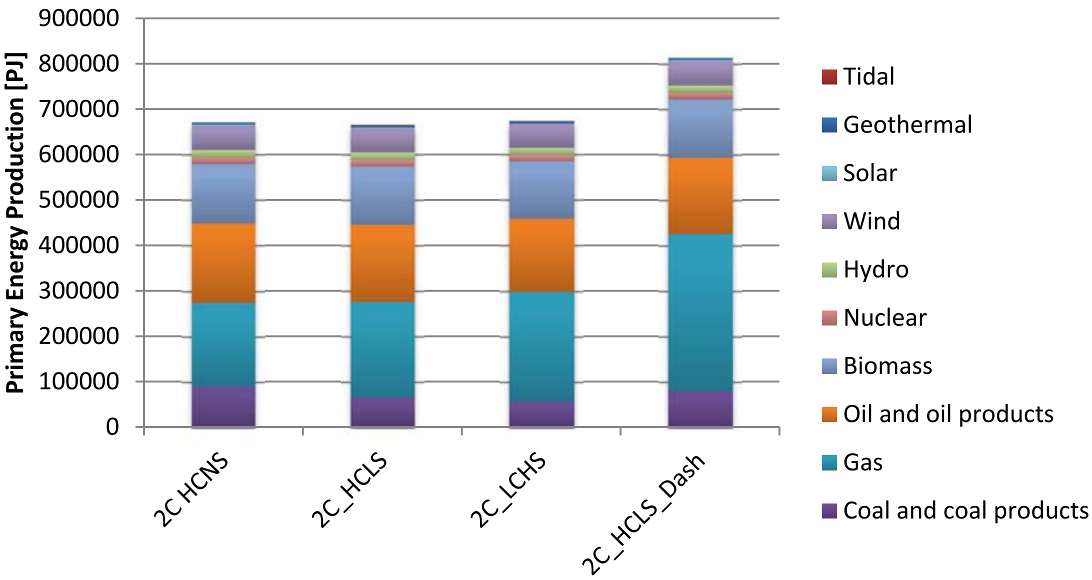


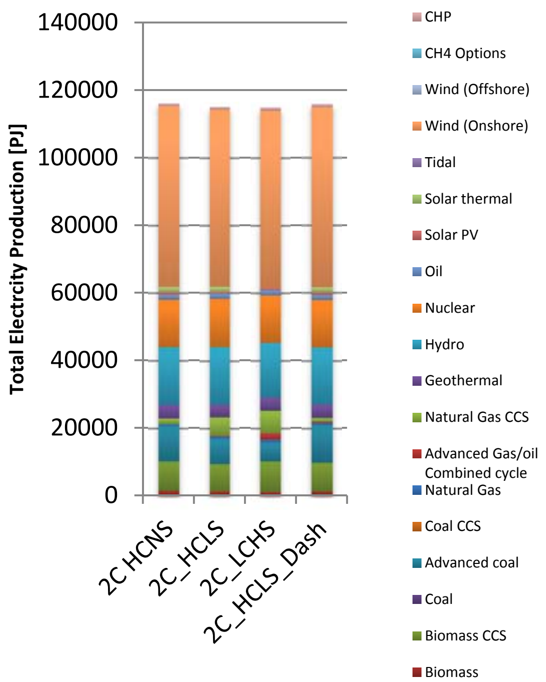
Figure D1 – 2030 Annual Primary Energy Production from a Range of Sources in a Range of Scenarios

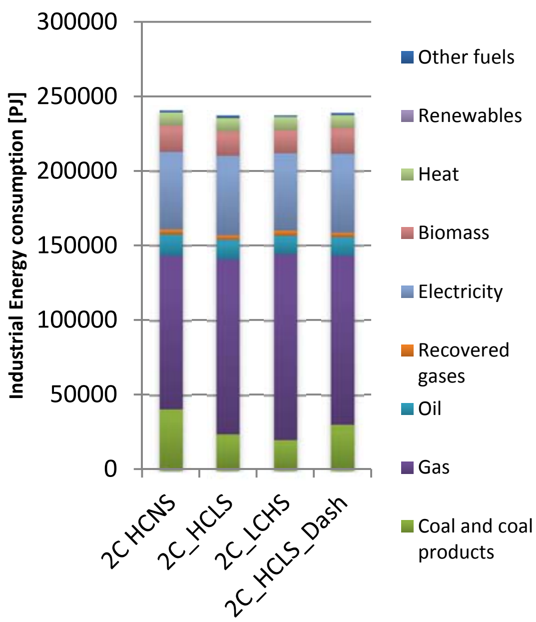
Figure D2 shows the breakdown of energy demand by fuel in a range of sectors in a range of scenarios, and Figure D3 summarises differences in sectorial in sectorial fuel consumption between HCNS and HCLS scenarios. In the "dash for shale gas" scenario, significant quantities of natural gas are stockpiled for use later in the model, whilst in other scenarios resource use is broadly in line with supply.

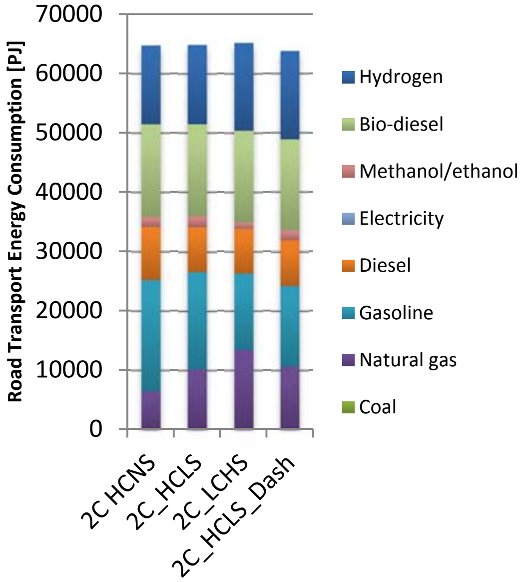
The industrial sector makes the largest contribution to shift in fuel mix use between HCNS and HCLS scenarios, accounting for 68% of the global decline in coal usage, and 57% of the increase in gas usage. Approximately half of this change occurs within the chemical industry, with the remainder shared between a range of industrial processes.

In HCLS in the electricity sector, natural gas generation with CCS replaces approximately a quarter of coal electricity generation in HCNS. This change accounts for 15% of the global decline in coal production, and 15% of the increase in gas usage. In the transport sector, natural gas is only used in road transport, where it displaces 14% of gasoline and diesel, accounting for 16% of global increase in gas usage. In the building sector, natural gas chiefly displaces demand for electricity and kerosene, accounting for 12% of the total increase in gas usage.

When gas becomes significantly less expensive in LCHS, gas extraction relative to HCNS increases by more than double that by which it increases in HCNS. However, in this case, only 37% of this additional gas usage is used in industrial processes, with around 12% displacing coal in the electricity sector, 12% displacing gasoline and diesel in the transport sector.







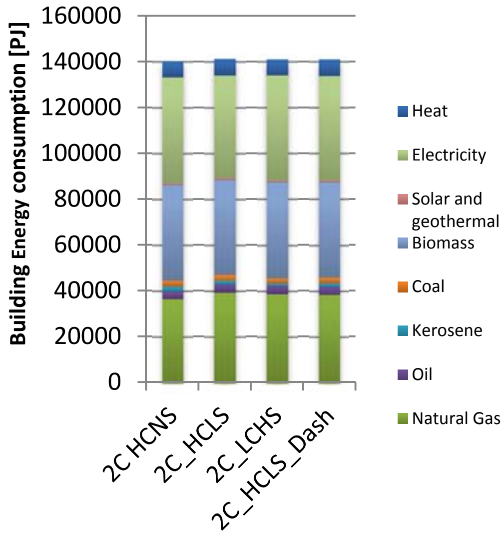


Figure D2 - 2030 Annual Primary Energy Demand from a Range of Sources in a Range of Scenarios broken down by Sector: (a) electricity, (b) industry, (c) transport, (d) residential and commercial buildings.

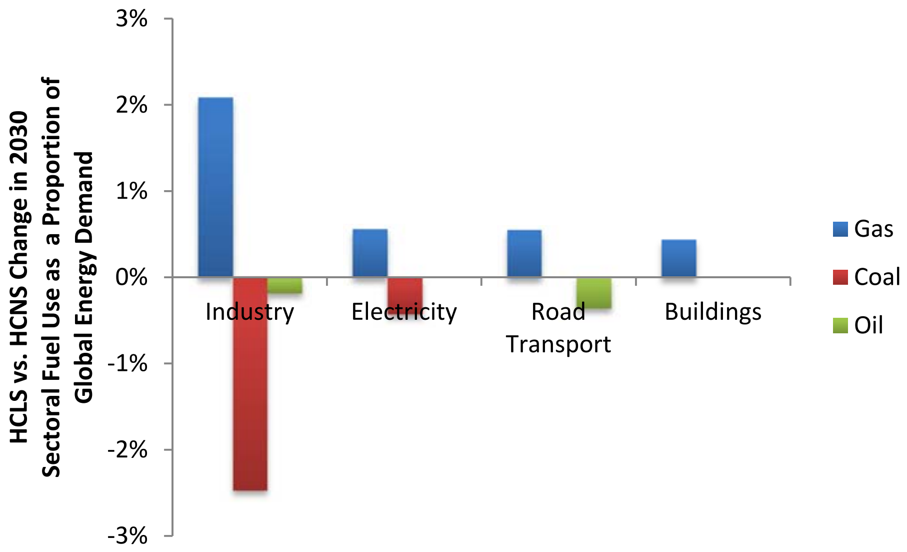


Figure D3 – Change in 2030 sectorial fuel use in HCLS scenario compared to HCNS scenario as a proportion of global energy demand

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