energies

MDPI

Article

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

Sheridan Few [1,*], Ajay Gambhir [1], Tamaryn Napp [1], Adam Hawkes [1], Stephane Mangeon [1], Dan Bernie [2] and Jason Lowe [2]

1 Grantham Institute, Imperial College London, Prince Consort Road, London SW7 2AZ, UK; a.gambhir@imperial.ac.uk (A.G.); tamaryn.napp@imperial.ac.uk (T.N.); a.hawkes@imperial.ac.uk (A.H.); stephane.mangeon12@imperial.ac.uk (S.M.)

2 Met Office Hadley Centre, FitzRoy Road, Exeter, Devon EX1 3PB, UK; dan.bernie@metoffice.gov.uk (D.B.); jason.lowe@metoffice.gov.uk (J.L.)

* Correspondence: sheridan.few@imperial.ac.uk; Tel.: +44-207-594-8457

Academic Editor: John Barrett

Received: 5 October 2016; Accepted: 17 January 2017; Published: 27 January 2017

Abstract: There exists considerable uncertainty over both shale and conventional gas resource availability and extraction costs, as well as the fugitive methane emissions associated with shale gas extraction and its possible role in mitigating climate change. This study uses a multi-region energy system model, TIAM (TIMES integrated assessment model), to consider the impact of a range of conventional and 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. When adding shale gas to the global energy mix, the reduction to the global energy system cost is relatively small (up to 0.4%), and the mitigation cost increases by 1%–3% under all cost assumptions. The impact of a "dash for shale gas", of unavailability of carbon capture and storage, of increased barriers to investment in low carbon technologies, and of higher than expected leakage rates, are also considered; and are each found to have the potential to increase the cost and reduce feasibility of meeting global temperature goals. We conclude that the extraction of shale gas is not likely to significantly reduce the effort required to mitigate climate change under globally coordinated action, but could increase required mitigation effort if not handled sufficiently carefully.

Keywords: shale gas; natural gas; supply curves; climate change mitigation; energy system analysis; energy scenarios; TIMES Integrated Assessment Model (TIAM); fugitive methane emissions; energy economics

1. Introduction

In recent years, there has been considerable global and regional interest in shale gas, which, it has been widely suggested, could play a role as a bridging fuel to a low-carbon future. There remains, however, considerable uncertainty over both shale and conventional gas resource availability and extraction costs, as well as the fugitive methane emissions associated with shale gas extraction. This leads to considerable uncertainty in the role which shale gas could play in mitigating climate change. This paper quantifies uncertainties in supply and fugitive emissions, and uses a model of the global energy system to quantify the impact of these uncertainties on global energy supply mix and the cost of mitigation scenarios.

This paper is organized as follows. The remainder of Section 1 provides a description of shale gas and how it differs from conventional gas, outlines reasons its extraction has been proposed, the known risks, and how energy system modelling can help us to understand its role. Section 2 provides an overview of the literature on shale and conventional gas supply and costs, and fugitive methane leakage associated with the extraction of shale gas. Section 2 also provides an overview of previous studies considering the role of shale gas in the future energy system, and identifies an analytical gap considering the implications of aforementioned uncertainties in 2 °C-consistent mitigation scenarios. Section 3 describes the TIMES Integrated Assessment Model (TIAM)-Grantham energy system model, and the manner in which it is used to address this gap. Section 4 presents results emerging from this study, including energy system and mitigation costs, the share of natural gas as a whole and shale gas specifically in primary energy mix, and rates of decarbonisation in a range of supply and cost scenarios. The impact of carbon capture and storage (CCS), cost of capital for other low-carbon technologies, and a "dash for shale gas" on cost and supply mix are considered, and selected region-specific results presented. Section 5 provides a discussion of the implications of this study for the possible role of shale gas in global climate change mitigation, and offers concluding remarks.

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. Both of these technologies have also been used in conventional gas extraction [1], 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, leading to the technique becoming more widespread [2].

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 (the term field appears to be used to refer both to individual plays and to entire basins, so we avoid the use of the term "field" in this paper) [3]. The US Energy Information Administration (EIA) [4] identifies shale plays in the USA which vary in size from hundreds to tens of thousands of square miles. More than 80% of shale gas production in the US comes from five of the largest plays [5]. During a mining operation, a number of wells will be constructed within such a play, from which gas will be extracted. Density of wells is variable, but the International Energy Agency (IEA) [6] 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).

McGlade et al. [7] identify two other unconventional sources of gas: tight gas trapped in relatively impermeable hard rock, and coal bed methane (CBM) trapped in coal seams. These unconventional sources do not form the core of this study, but are discussed in the model results.

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 led to a tenfold increase in production of shale gas between 2006 and 2010, and reached 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 [8]. The possibility of emulating this phenomenon 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" [6].

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, CO_2 emissions in the USA are reported to have fallen by 11% [9], and a 4% reduction in CO_2 emissions over this period has been attributed to a shift in the fuel consumption mix from coal to natural gas, with a decrease in consumption volume and changes in production structure making up other significant contributing factors [10]. In addition, gas turbines are able to provide flexible generation, helping to balance supply form intermittent renewable electricity sources such as wind and solar photovoltaics [11]. These factors combined have led some analysts and political leaders 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 the US President Barack Obama describing fracking as a "bridge" to a clean energy future [12].

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 long-term lock-in to gas when climate targets require a move to lower-carbon technologies coupled with diversion of funds from lower carbon technologies, fugitive methane emissions, as well as local environmental impacts and acceptability [2,13].

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 yet be described as authoritative. Literature on the global shale gas resource and depletion is explored in more detail in Sections 2.1 and 2.2, and literature on extraction costs in Section 2.4.

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 (86 times higher over a 20 year timeframe, and 34 times higher over a 100 year time frame [14]) due to the differing absorption profiles and atmospheric lifetimes of the two gases. As such, if leakage rates are higher than around 4%, the 20-year climate benefits of using gas rather than coal for electrical power are eradicated [15]. Leakage rates ranging from less than 0.5% to above 10% have been reported across hydraulic fracturing sites, using different measurement methodologies. A more detailed overview of literature on leakage rates is provided in Section 2.3.

Other concerns not considered in detail in this report include the 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 [16], and strong local opposition in some communities [17]. A draft report from the US Environmental Protection Agency [18] concludes contamination of drinking water associated with hydraulic fracturing has taken place, although on what scale remains unclear. The local environmental impacts of shale gas extraction are discussed in Hirst et al. [2], and the importance of information collection, access, and dissemination to support evidence-based shale gas policies are outlined by Gamper-Rabindran [19].

1.4. What Can Energy System Modelling Tell Us about the Role of Shale Gas?

Computational modelling of the energy system represents a powerful approach for planning, capable of providing indication of possible energy system pathways, and the impact of technology and resource costs and availabilities, and emissions constraints on the costs and feasibilities of achieving these pathways [20,21]. As such, we consider the modelling of the global energy system an appropriate tool for evaluating the impact of shale gas on the cost and feasibility of meeting climate targets.

Energy system models are nonetheless subject a number of limitations. Firstly, 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. Secondly, these models are often based upon optimal decisions. However, 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. Thirdly, these models typically assume perfect foresight of future energy needs, technology costs and fossil fuel supply costs, which will not be the case in practice. In the context of these limitations, exact numerical results are likely to differ between models depending upon their implicit assumptions. As such, more value should be attributed to general trends, directions and orders of magnitude of results than exact numerical values.

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. [7] provide a review of literature on shale gas reserves, alongside an overview of terminology surrounding gas resources, reproduced in Table 1.

Table 1. Interpretation of resource terminology, reproduced from [7].

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

As early as 1997, Rogner [22] made an early estimate of volumes of original gas in place (OGIP) 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 estimates [7], the width of this range reflecting 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. [7] described the 2011 ARI study as "the new benchmark", and combine published TRR estimates for a number of regions to produce their own "low", "central", and "high" global estimates, broken down into individual regions, of which the 2011 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 globally. 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 and co-workers' earlier estimates (although methodological details are not provided in the BGR study, 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

In addition to uncertainty around the ultimately and technically recoverable resources, there is also considerable uncertainty surrounding the manner in which individual shale plays, and individual wells within those plays, may deplete, and hence the quantity of economically recoverable resources from shale formations [29].

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 [30,31], but sources differ on the future productivity of shale gas plays, particularly as productivity from wells in "sweet spots" declines [32]. (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 [33]. However, the magnitude of difference between scenarios proposed by the EIA and projections presented by University of Texas remains significant.) Hughes suggests that the economic investment currently required to build a higher number of wells to replace declining supply from the most productive wells is not being, and will not be, recuperated at current gas prices [31]. Furthermore, Hughes asserts that drop-off rates of supply from shale gas wells assumed by many in the industry are unrealistically, low and lead to overestimates of ultimate recoveries and economic performance [31]. In a later report, Hughes forecasts "most likely" total production from major shale plays to be approximately two thirds of that projected by the EIA up to 2040 [34]. Other commentators have contested this interpretation, taking recent history of shale gas production in the USA as evidence that future estimates are realistic [35].

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. Stevens [36] 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. However, these studies imply that there could be significant space for downward revision of estimates where forecasts are produced with methods similar to those used to project US shale production. This remains an area of on-going debate and analysis.

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 (see Section 1.3 on known risks). Emissions from natural gas are typically divided into "upstream" emissions associated with extraction, and "downstream" emissions associated with storage and transmission. A summary of literature on upstream methane emissions associated with shale gas extraction is provided in Figure 1 below, and more details of these studies are provided in Supplementary Materials. These studies broadly fall into one of four methodologies: literature review, bottom-up, atmospheric measurement, and satellite measurement. Whilst downstream emissions represent a significant contributor to fugitive emissions, these emissions are not considered in detail here, as they are expected to be similar for shale gas and conventional sources of gas.

Bottom-up assessments 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 the difficulty of source apportionment represents a fundamental challenge in such studies). Results from satellite measurements taken prior to and during the shale boom in the US are also included here. Both atmospheric and satellite measurements indicate that emissions associated with shale gas extraction have often been significantly higher than indicated by bottom-up studies. Miller et al. [37] reviewed atmospheric measurements in the US, concluding that the US Environmental Protection Agency (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) [38], described by the authors as the most comprehensive global methane inventory.

Reports by Howard et al. [39,40] stated that a sensor failure is likely to have led to significant underestimates in fugitive emissions in bottom-up studies, in particular the Allen and co-workers' major 2013 study of emissions in a large number of US gas wells [41]. Some of these claims have been contested, and this remains an area of on-going debate and analysis [40,42].

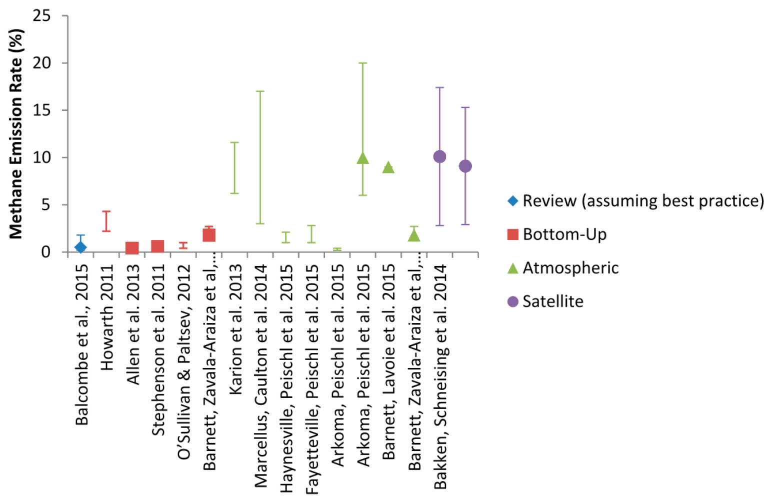


Figure 1. A summary of literature on methane emissions associated with shale gas extraction [41,43–52]. More details of these studies are provided in Supplementary Materials.

Balcombe and co-workers' (2015) literature reviewed on fugitive emissions from shale gas extraction presents a range of upstream 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 unresolved 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 [53], and the International Energy Agency indicated that policy directed towards reduction in upstream methane emissions could play an important role in climate change mitigation [54].

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) [55].

2.4. Shale Gas Supply Curves in Previous Energy System Modelling Studies

There have been a number of key studies on the impacts of shale gas on global greenhouse gas emissions in recent years. The scope, methodologies, and key conclusions of these studies are outlined in this section.

In a 2014 study, McJeon et al. [56] considered how reductions in all (conventional and unconventional) gas costs would affect greenhouse gas emissions in a scenario where there is no climate policy, comparing results of a range of integrated assessment models of the future global energy system. McJeon et al. used costs from the IIASA Global Energy Assessment (GEA) [57] (Figure 2), for which both conventional and unconventional gas are relatively low compared to other sources, and assume gas extraction costs to halve between 2010 and 2050 in an "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 [58] 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.) No difference in methane leakage rates are assumed between shale and non-shale sources. This study concludes that, in a "more abundant" gas scenario with no climate policy, gas displaces some coal, and some low carbon energy sources, and that abundant gas has little impact on radiative forcing.

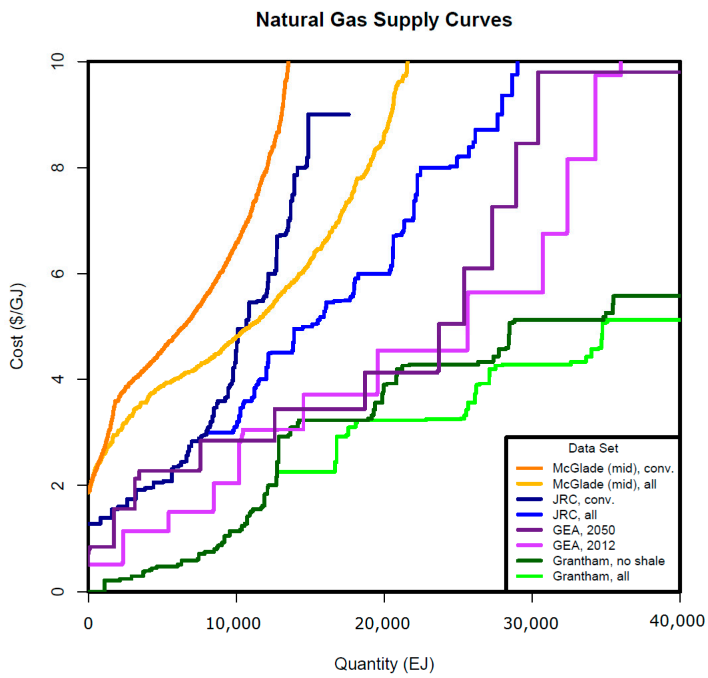


Figure 2. Marginal cost of extraction of gas from a range of sources: including only conventional, and including conventional and unconventional extraction methods. McGlade 2013 [58], JRC 2012 [59], GEA 2012 [57], energy technology systems analysis programme (ETSAP)-TIAM 2005 [60].

In a 2013 study, Gracceva et al. [59] considered the economic role of shale gas in the global energy system up to 2040 under shale gas cost and supply scenarios described as "optimistic", "pessimistic", and "most likely". Gracceva et al. use an integrated assessment model (JRC energy technology systems analysis programme (ETSAP)-TIAM) of the future energy system, with costs and resource potentials updated by the JRC to account for new estimates of conventional gas availability. Shale gas costs are taken from recent regional cost and resource potential estimates [59]—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 [58]. This study finds a notable role for shale gas only when taking the most optimistic resource size assumptions coupled with the most optimistic cost assumptions (45% of an "optimistic" estimate of approximately 350 Tcm (~13,000 EJ) shale gas reserves extractable at an "optimistic" cost of $4.5/GJ).

McGlade and Ekins' 2014 study [61] uses an integrated assessment model of the future energy system (TIAM-UCL) with resource and cost estimates as described in McGlade's [58] doctoral thesis to calculate the regional distribution of fossil fuels unburnt when limiting global warming to 2 °C. This study suggests that 68% of conventional, and 82% of unconventional gas should remain unburnt by 2050, and does not explicitly specify the proportion of unburnt shale gas.

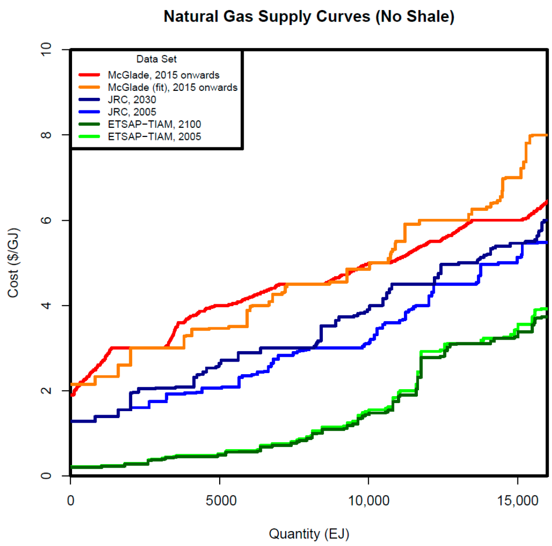
The IEA's 2011 "Golden Age of Gas" report [62] estimates remaining recoverable resources and price ranges of conventional and unconventional gas by region, although the methodology used to derive these estimates is unclear. Extraction costs for shale gas are estimated only in North America, where the range is similar to conventional gas, but marginally above conventional gas prices in Russia and the Middle East.

Figure 2 shows the global supply/cost curves for conventional gas only, and for all gas including shale and other unconventional sources of gas (coal bed methane and tight gas) used in the above studies. (In McGlade's analysis, a relatively large uncertainty range is included in both conventional and unconventional resources. In Gracceva et al.'s study, estimates of shale gas resource availabilities and production costs described as "high", "most likely", and "low" are included for shale gas. In both cases, middle ranges are included here.) This demonstrates the large difference in assumptions about supply made by a number of reputable sources, although it should be noted that in all cases TRR shale resources are estimated based upon the assessment published by McGlade [7]. In Gracceva et al.'s [59] supply curves, 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) [63]. In McGlade's [58] 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 taken into account. Stevens [36] notes that these factors could result in significantly higher costs in the UK than the USA, and many of these factors would also be likely to apply to other regions.

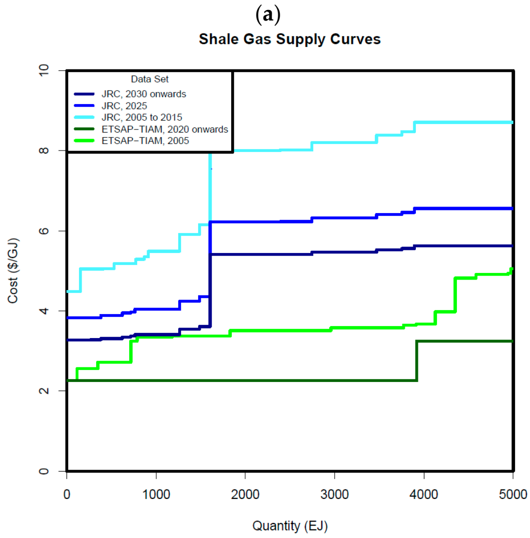
Figure 3 shows gas supply curves separated into non-shale (predominantly conventional) and shale resources. Shale gas in both ETSAP and the JRC's marginal cost of extraction curves is divided into three cost bands in each of the fifteen regions considered in the global ETSAP-TIAM energy system model. From these curves, it is apparent that shale gas extraction is only currently cost competitive with the least expensive 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, and McGlade [58] finds no clear evidence for significant long term reduction in fossil fuel extraction costs, it is not clear whether this is a reasonable assumption. Figure 3a demonstrates that in both the ETSAP-TIAM and JRC analysis, there is around 5000 EJ of non-shale gas available at a cost of below approximately $2/GJ. A comparison with Figure 3b shows that this gas is less costly than the cheapest shale gas extraction.

In addition to assessment of global supply, a number of supply curves have been published for shale gas in individual plays and for the USA alone. US supply curves provided by Hilaire et al. [64] and Jacoby et al. [65] report a similar quantities of shale gas to the JRC's [58] central estimate, but at a slightly higher cost. Those of Petak et al. [66] fall between JRC and ETSAP-TIAM [59] estimates. Gülen et al. [67] model supply and cost of gas divided in to ten tiers in the Barnett shale in Texas, emphasising the importance of high resolution sampling in obtaining accurate results.

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. 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.



(**a**)



(**b**)

Figure 3. Marginal cost of extraction of gas from a range of sources. (**a**) Non-shale; and (**b**) shale [57–60]. Note: 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 scenarios with no climate-policy 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 achieve 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 on the use of a global energy systems model, TIAM-Grantham, to explore reference and mitigation scenarios to 2100. TIAM-Grantham is the Grantham Institute of Imperial College London's version of the ETSAP-TIAM model, which is the global, 15-region incarnation of the TIMES model generator, as developed and maintained by the energy technology systems analysis programme (ETSAP), and described in detail in References [21,68]. 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. In a typical run, the TIAM model will optimise the energy system for given climate constraints through maximising total producer and consumer welfare over a given time horizon while accounting for elastic demand responses to energy prices.

The model uses exogenous inputs of factors such as gross domestic product (GDP), population, household size and sectorial 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.

The 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 1340 $GtCO_2$ 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 [69]. 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 [69]. It should be noted that 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 2030 emissions levels broadly similar to 2020 levels presented here [70]. A further model run is carried out consistent with a 50% likelihood of keeping 2100 temperature change below 1.75 °C, close to the limit of temperature change feasible within the constraints applied to the model.

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 [71] where global economic output grows from (2005 US, PPP) $68 trillion in 2010 to $539 trillion in 2100. A discount rate of 5% is assumed (a standard societal discount rate value used in global energy system modelling exercises [69,72,73]) over the period 2012–2100. 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 Table 2.

Table 2. Conventional and unconventional gas cost/supply scenarios.

Cost Scenario	Description
Low Cost Conventional (LC)	Conventional, tight gas, and coal bed methane cost curves from ETSAP-TIAM 2006 [60] (green lines in Figure 3a).
Mid Cost Conventional (MC)	Conventional, tight gas, and coal bed methane cost curves from JRC [59] (blue lines in Figure 3a).
High Cost Conventional (HC)	Conventional, tight gas, and coal bed methane cost curves from JRC [59] scaled such that conventional costs are in line with McGlade [58] (orange line in Figure 3a).
Low Cost Shale (LS)	Shale cost curves from ETSAP-TIAM 2012 model version, based upon McGlade [58]. Costs are similar to McGlade's thesis up to 2015, with costs in all regions falling to that of lowest cost region in McGlade [58] by 2020 (green lines in Figure 3b).
Mid Cost Shale (MS)	Shale cost curves from ETSAP-TIAM 2012 model version based upon McGlade [58], adapted such that there is no fall in costs in any region during the model run (light green line in Figure 3b).
High Cost Shale (HS)	Shale cost curves from JRC [59] mid case (blue lines in Figure 3b).
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 core 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").

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. (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, changes uptake of gas by less than 1% in any year and changes discounted energy system cost by less than 0.01%.).

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 (the required annual repayment rate of an initial capital loan for the construction of these plants) for low carbon electricity technologies are increased.

We also consider energy system pathways in a "dash for shale gas" scenario, in which governments implement policy resulting in rapid extraction of shale gas, despite it being economically suboptimal (for example, in order to ensure energy security, under a 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 a high 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. 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, and the potential risks if such measures prove to be ineffective.

4. Results

4.1. Energy System and Mitigation Costs

Table 3 shows the cost of the discounted global energy system calculated for a range of cost and availability combinations of conventional and shale gas in both the reference scenarios and mitigation scenarios. This cost includes all primary energy fuels and energy conversion technologies, spanning extraction to end-use of energy throughout the global economy. Table 3 also shows the mitigation cost for each conventional/shale gas cost combination, defined as the difference between the cost of the energy system in the mitigation and reference scenarios. 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 each case, mitigation costs fall in the range 33–35 trillion 2005 US$ (1.05% and 1.11% of global GDP). This is towards the lower end of the $34–288 trillion previously reported by Gambhir et al. [69] and the $12–120 trillion reported by Clarke et al. [73], each across models and scenarios.

Table 3. Cumulative discounted cost of the energy system, and cumulative discounted cost of mitigation.

Conventional Gas Cost Scenario		Unconventional Gas Cost Scenario	Abbreviation	Present Value Energy System Cost over the Period 2012–2100 *		
				2 °C Scenario/Trillion 2005 US$	Reference Scenario/Trillion 2005 US$	Mitigation Cost/Trillion 2005 US$ (%GDP)
With shale	Low Cost	High Cost Shale	LC_HS	635.2	601.0	34.1 (1.09)
	Mid Cost	Mid Cost Shale	MC_MS	641.8	607.1	34.7 (1.11)
	High Cost	Low Cost Shale	HC_LS	643.2	609.1	34.1 (1.09)
No shale	Low Cost	No Shale	LC_NS	634.4 ‡	601.3	33.1 (1.05)
	Mid Cost	No Shale	MC_NS	642.9	609.0	33.9 (1.08)
	High Cost	No Shale	HC_NS	645.7	612.7	33.0 (1.05)

Notes: In all cases the rate of extraction of shale gas is optimised in order to maximise welfare, and a standard capital financing rate of 10% is used for low carbon electricity technologies. * Discount rate 5% used to calculate cumulative discounted cost; ‡ 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.

As shown in Table 3, 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 from the LC_NS to the HC_LS scenarios is relatively large compared to the 0.31% increase from the MC_NS to the MC_LS scenarios (both with and without a 2 °C target). This indicates that system cost is more sensitive to uncertainties in cost for conventional gas cost than for shale gas. Energy system pathways associated with other combinations of costs of conventional gas and cost and availability of shale gas have been explored, and are described using similar nomenclature in a table provided in Supplementary Materials.

4.2. Primary Energy Share of Natural Gas

Figure 4 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). In all cases, 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 is substituted by an increasing penetration of renewable energy sources. Figure 4 also illustrates that the most influential factor on global primary natural gas demand in the mitigation scenarios is the cost of conventional gas, since there is significantly higher gas demand only in the scenario with the lower end of the cost range for conventional gas (LC_HS).

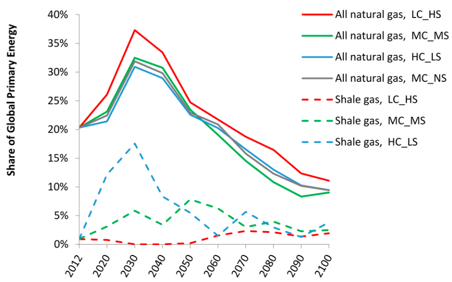


Figure 4. Share of global primary energy supplied by (solid lines) all natural gas, and (dashed lines) shale gas in 2 °C consistent energy systems in a range of cost scenarios for conventional and shale gas.

In the HC_LS, scenario, 13% of total primary energy is provided by shale gas in the period 2016–2040. In a similar scenario without shale gas (HC_NS), total primary energy demand is within 0.5% of that in HC_LS, with the energy which would otherwise be supplied by shale gas predominantly provided by other sources of natural gas (an additional 8% of total primary energy from conventional sources, and 1% each from tight gas and coal bed methane), but to some extent also coal, renewables and oil (2%, 1%, and 1%, respectively). In the MC_MS and LC_HS scenarios, respectively, 4% and 0.3% of total primary energy is supplied by shale gas in the period 2016–2040. In similar scenarios with no shale gas, energy consumption varies by less than 0.01%, with energy otherwise supplied by shale gas predominantly met by other sources of gas (an additional 1% of total primary energy from conventional sources, and 2% from coal bed methane in MCNS, and differences in each energy vector <1% in LCNS). Temporal profiles of changes in sources of primary energy consumption with and without shale gas in each of these cost scenarios are provided in Supplementary Materials.

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. 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 that field. Therefore, potential economic benefits of shale gas extraction even from these sources may be challenging to realise. In the period 2016–2040, 4600–5500 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 [74], and 65%–82% of the range presented by the GEA in 2012 [57].

In the MC_NS scenario, 4% less natural gas is used across the entire period 2012–2100 than in 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 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.)

On the demand side, when low cost shale gas is added to a scenario with high conventional costs (i.e., HC_LS compared to HC_NS), gas extraction increases by 14% in 2030 (the year of peak gas extraction in our study), and coal extraction reduces 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, 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 Supplementary Materials.

In a pathway consistent with a 50% chance of limiting global warming to 1.75 °C (close to the lowest temperature rise achievable using TIAM-Grantham) in the MC_NS scenario, the global gas demand for the period 2016–2040 is 4400 EJ (compared to 4700 EJ for a 2 °C consistent pathway with the same gas costs and availabilities). This implies that the role of all gas, including that derived from shale sources, should be diminished rather than increased in order to meet more ambitious temperature targets as set out in the in the UNFCCC Paris Agreement [75].

Gas extraction in reference scenarios with no action to mitigate climate change is provided in Supplementary Materials, alongside the temporal evolution of total energy demand, and more details of the overall mix of energy resources.

4.3. Impacts of Carbon Capture and Storage (CCS) on Gas Share of Global Primary Energy

The total quantity of carbon captured between 2020 and 2100 (the period of globally coordinated mitigation action in our 2 °C scenarios) is within 5% in all core gas cost scenarios. Figure 5a shows the rate of carbon capture from a range of sources in a 2 °C consistent MC_NS pathway. Figure 5b shows the cumulative demand for conventional and shale gas in a number of gas cost scenarios over the same period, indicating 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 2005 US$10,000/t$CO_2$. These scenarios are therefore deemed to indicate economic and technical infeasibility of meeting the 2 °C goal within the constraints applied to the TIAM-Grantham model.

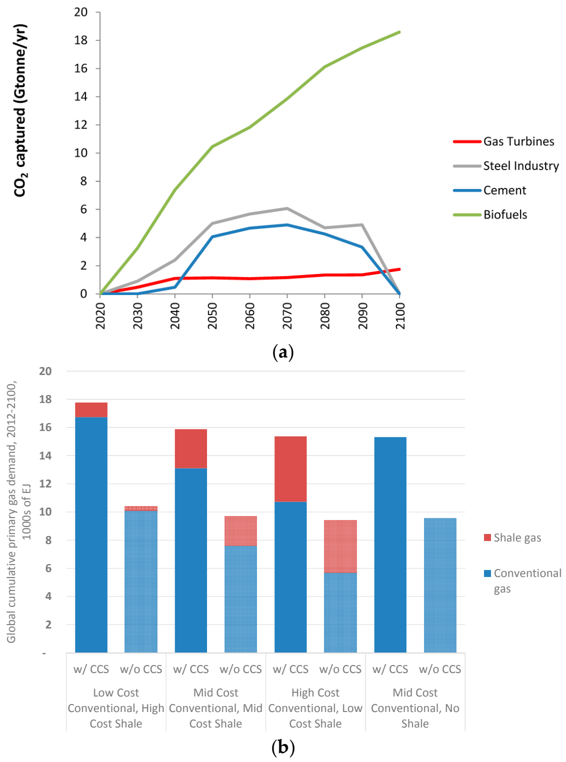


Figure 5. (**a**) Rate of carbon capture from a range of sources in a scenario with mid-cost conventional and no shale gas; and (**b**) global cumulative primary demand for natural gas over the period 2012–2100, in 2 °C mitigation scenarios with and without availability of CCS.

4.4. Region-Specific Results

Only in the HC_LS scenario is there significant 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. Extraction rates of all natural gas, shale gas, and coal in each region in the period 2012–2020 are presented for the three core scenarios, LC_HS, MC_MS, and HC_LS in Supplementary Materials. However, we emphasise that our model is global in scale, and more detailed regional models are necessary to properly understand regional dynamics.

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 (here taken to include solar, wind, tidal, hydro, geothermal, nuclear power, and biomass for electricity generation) are increased. These scenarios are used 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. Energy system costs under these scenarios are presented in Table 4. The exact values chosen changes to capital financing rates are necessarily somewhat arbitrary, as there is little evidence surrounding the impact of shale gas investment on capital availability (and hence the cost of capital) for low-carbon electricity technologies. As such, results in this section serve to illustrate the potential mitigation cost impact of different capital financing rate increases, rather than directly addressing the mitigation cost impact of investment in shale gas.

Table 4. 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	Capital Financing Rates for Low Carbon Electricity Technologies	Present Value Energy System Cost over the Period 2012–2100 *		
			2 °C Scenario/Trillion 2005 US$	Reference Scenario/Trillion 2005 US$	Mitigation Cost/Trillion 2005 US$ (%GDP)
Low Cost	High Cost Shale	10%	635.2	601.0	34.1 (1.09)
Mid Cost	Mid Cost Shale	10%	641.8	607.1	34.7 (1.11)
High Cost	Low Cost Shale	10%	643.2	609.1	34.1 (1.09)
Low Cost	High Cost Shale	11%	636.7	601.0	35.6 (1.13)
Mid Cost	Mid Cost Shale	11%	643.0	607.1	35.9 (1.14)
High Cost	Low Cost Shale	11%	644.2	609.1	35.1 (1.12)
Low Cost	High Cost Shale	20%	652.8	601.0	51.7 (1.65)
Mid Cost	Mid Cost Shale	20%	659.5	607.1	52.5 (1.67)
High Cost	Low Cost Shale	20%	660.9	609.1	51.8 (1.65)

* Discount rate 5% used to calculate cumulative discounted cost.

Table 4 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% increase in capital financing rates increases mitigation costs by 3%–4% (1.0–1.5 trillion US$2005) over the period 2012–2100. An extreme case in which capital finance rates double leads to mitigation costs which are 51%–52% higher than the standard financing rate cases.

4.6. Impact of a "Dash for Shale Gas"

In order to consider the 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 in considered shale gas cost curves) is extracted by 2050. Figure 6 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. Energy system costs in these scenarios are presented in Table 5.

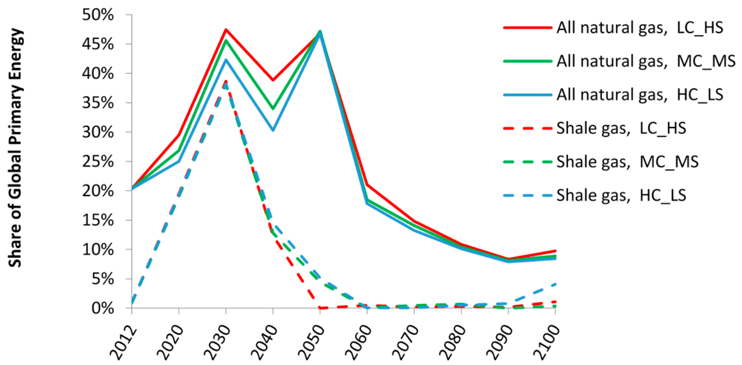


Figure 6. Share of global primary energy supplied by (solid lines) all natural gas, and (dashed lines) shale gas in a range of cost scenarios for conventional and shale gas under a "dash for shale" scenario.

Table 5. 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)

* Discount rate 5% used to calculate cumulative discounted cost.

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 global 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.

These results follow from the analysis of shale and conventional gas cost relativities as presented in Section 2, indicating that there is significant conventional gas available at a cost below that of shale gas. As such, rapid extraction of shale gas is far from cost-optimal in a global context.

4.7. Rates of Decarbonisation

Figure 7 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.

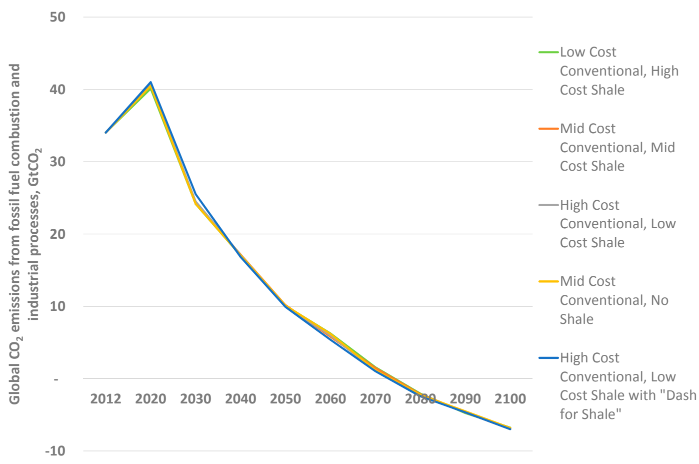


Figure 7. Global fossil fuel and industrial CO_2 emissions in a range of 2 °C scenarios.

The "dash for shale" scenario differs slightly from other scenarios 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 in rates of decarbonisation to be sufficient to draw specific conclusions about the impact of exploitation of shale gas on the feasibility of mitigation. In all scenarios, the near-term rates of decarbonisation required are around 5% per year in the decade 2020–2030, a level unprecedented at a global level and therefore all likely to be challenging to achieve in practice (although higher rates have been achieved at an individual country level [76]).

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 References [69,77].

Figure 8 shows that, for the high cost conventional, low cost shale (HC_LS) scenario, in which exploitation of shale gas is highest among scenarios with no forced extraction, 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 above that of conventional gas extraction. If there were a dash for shale gas, then a fugitive methane leakage rate of 5% would result in a 50% likelihood of the 2 °C threshold being exceeded in 2050 (see Supplementary Materials).

This analysis thus suggests that the reduction of fugitive methane leakage could be an important factor in keeping global average temperature change "well below 2 °C" as stated in the UNFCCC Paris Agreement [75]. 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), as discussed in Section 2.3. As such, 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 effective control or mitigation of fugitive methane is important if large-scale extraction of shale gas were to take place.

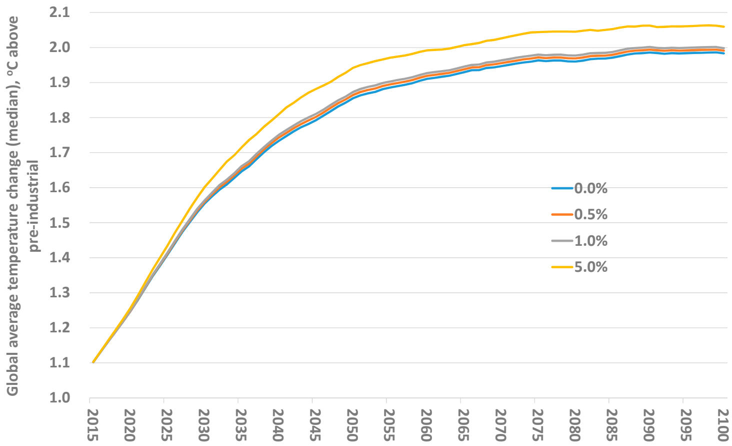


Figure 8. Median temperature change with different assumptions on unmitigated fugitive methane leakage from shale wells, high cost conventional, low cost shale (HC_LS) scenario.

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); and 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 could make up more than 10% of global primary energy supply in the period 2020–2040 in an economic welfare-maximising 2 °C consistent energy system transition pathway. However, in all other considered cost scenarios, shale gas makes up 6% or less of global primary energy supply in the same period. 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. The role of natural gas is further diminished in a 1.75 °C scenario, close to the limit of what is achievable using our model.

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 capital constraints leading to a 1%-point increase (from 10% to 11%) 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 current challenges in monitoring and mitigation must be overcome before embarking on widespread extraction of gas from shale formations.

In summary, provided fugitive emission rates can be controlled, 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. 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.

Supplementary Materials: Supplementary materials can be found at www.mdpi.com/1996-1073/10/2/158/s1.

Acknowledgments: Sheridan Few, Ajay Gambhir, and Tamaryn Napp wish to thank the Department of Energy and Climate Change for support in conducting this analysis through the AVOID 2 Programme under contract reference No. 1104872. Sheridan Few and Ajay Gambhir wish to thank Francesco Gracceva and Haewon McJeon for providing valuable comments on an earlier version of this manuscript, and Francesco Gracceva and the European Commission Joint Research Centre for generously sharing the supply–cost curves used in their analysis of the potential role for conventional and shale gas.

Author Contributions: Sheridan Few led the analysis, performed model runs, reviewed literature on shale and conventional gas, and wrote the bulk of the paper; Ajay Gambhir supported and conducted additional analysis, contributed to the writing of the paper, and coordinated parties; Tamaryn Napp and Adam Hawkes provided training and support in use of the TIAM-Grantham model; Stephane Mangeon reviewed literature on shale gas cost and resource; Dan Bernie calculated temperature profiles associated with greenhouse gas emissions arising from TIAM-Grantham model runs; and Jason Lowe acted as chief scientist for the AVOID 2 Programme.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. The Royal Society. *Shale Gas Extraction in the UK: A Review of Hydraulic Fracturing*; The Royal Society: London, UK, 2012.
2. Hirst, N.; Khor, C.S.; Buckle, S. Shale gas and climate change. In *Grantham Institute Briefing Papers*; Grantham Institute: London, UK, 2013.
3. US Energy Information Administration Shale Gas Glossary. Avilable online: http://energy.gov/sites/prod/files/2013/04/f0/shale_gas_glossary.pdf (accessed on 3 March 2016).
4. U.S. Energy Information Administration (EIA) Lower 48 States Shale Plays 2015. Available online: http://www.eia.gov/oil_gas/rpd/shale_gas.pdf (accessed on 23 January 2017).
5. U.S. Energy Information Administration (EIA) EIA to Release New Drilling Productivity Report. Available online: http://www.eia.gov/todayinenergy/detail.cfm?id=13451 (accessed on 23 January 2017).
6. International Energy Agency. *Golden Rules for a Golden Age of Gas*; International Energy Agency: Paris, France, 2012.
7. Mcglade, C.; Speirs, J.; Sorrell, S. Unconventional gas—A review of regional and global resource estimates. *Energy* **2013**, *55*, 571–584. [CrossRef]
8. U.S. Energy Information Administration (EIA) Natural Gas Data. Avilable online: https://www.eia.gov/naturalgas/data.cfm (accessed on 3 March 2016).
9. U.S. Energy Information Administration (EIA). *U. S. Energy-Related Carbon Dioxide Emissions, 2013*; U.S. Energy Information Administration: Washington, DC, USA, 2014.
10. Feng, K.; Davis, S.J.; Sun, L.; Hubacek, K. Drivers of the US CO_2 emissions 1997–2013. *Nat. Commun.* **2015**, *6*. [CrossRef] [PubMed]

11. International Energy Agency. *Energy Technology Perspectives*; International Energy Agency: Paris, France, 2014.
12. Obama, B. State of the Union Address. Available online: https://obamawhitehouse.archives.gov/the-press-office/2014/01/28/president-barack-obamas-state-union-address (accessed on 23 January 2017).
13. Richter, P.M. *From Boom to Bust? A Critical Look at US Shale Projections*; DIW Berlin Discussion Paper; DIW Berlin: Berlin, German, 2013.
14. IPCC. Anthropogenic and Natural Radiative Forcing. In *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*; Cambridge University Press: Cambridge, UK; New York, NY, USA, 2013; pp. 659–740.
15. Alvarez, R.A.; Pacala, S.W.; Winebrake, J.J.; Chameides, W.L.; Hamburg, S.P. Greater focus needed on methane leakage from natural gas infrastructure. *Proc. Natl. Acad. Sci. USA* **2012**, *109*, 6435–6440. [CrossRef] [PubMed]
16. United States Government Accountability Office (GAO). *Unconventional Oil and Gas Development: Key Environmental and Public Health Requirements*; United States Government Accountability Office: Washington, DC, USA, 2012.
17. Whitmarsh, L.; Nash, N.; Upham, P.; Lloyd, A.; Verdon, J.P.; Kendall, J.M. UK public perceptions of shale gas hydraulic fracturing: The role of audience, message and contextual factors on risk perceptions and policy support. *Appl. Energy* **2015**, *160*, 419–430. [CrossRef]
18. United States Environmental Protection Agency. *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources Executive Summary*; United States Environmental Protection Agency: Washington, DC, USA, 2015.
19. Gamper-Rabindran, S. Information collection, access, and dissemination to support evidence-based shale gas policies. *Energy Technol.* **2014**, *2*, 977–987. [CrossRef]
20. Pfenninger, S.; Hawkes, A.; Keirstead, J. Energy systems modeling for twenty-first century energy challenges. *Renew. Sustain. Energy Rev.* **2014**, *33*, 74–86. [CrossRef]
21. Loulou, R.; Labriet, M. ETSAP-TIAM: The TIMES integrated assessment model Part I: Model structure. *Comput. Manag. Sci.* **2007**, *5*, 7–40. [CrossRef]
22. Rogner, H. An assessment of world hydrocarbon resources. *Annu. Rev. Environ. Resour.* **1997**, *22*, 217–262. [CrossRef]
23. Advanced Resources International. *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*; Advanced Resources International: Arlington, VA, USA, 2011.
24. Medlock, K.B. Shale gas, emerging fundamentals, and geopolitics. In *James A Baker III Institute for Public Policy*; Rice University: Houston, TX, USA, 2012.
25. Advanced Resources International. *EIA/ARI World Shale Gas and Shale Oil Resource Assessment*; Advanced Resources International: Arlington, VA, USA, 2013.
26. Federal Institute for Geosciences and Natural Resources (BGR). *Energy Study—Reserves, Resources and Availability*; Federal Institute for Geosciences and Natural Resources: Berlin, Germany, 2015.
27. Polish Geographical Survey. *Assessment of Shale Gas and Shale Oil Resources of the Lower Paleozoic Baltic-Podlasie-Lublin Basin in Poland*; Polish Geological Institute: Warsaw, Poland, 2012.
28. Efstathiou, J., Jr.; Klimasinska, K. *U.S. to Slash Marcellus Shale Gas Estimate 80% on Geology Update*; Bloomberg: New York, NY, USA, 2011.
29. McGlade, C.; Speirs, J.; Sorrell, S. Methods of estimating shale gas resources—Comparison, evaluation and implications. *Energy* **2013**, *59*, 116–125. [CrossRef]
30. Urbina, I. Insiders Sound an Alarm Amid a Natural Gas Rush. *New York Times*, 25 June 2011.
31. Hughes, J.D. A reality check on the shale revolution. *Nature* **2013**, *494*, 307–308. [CrossRef] [PubMed]
32. Inman, M. The fracking fallacy. *Nature* **2014**, *516*, 28–30. [CrossRef] [PubMed]
33. US Energy Information Administration Response to "Fracking Fallacy" Article 2014. Available online: http://www.eia.gov/naturalgas/article/Nature_news_feature.pdf (accessed on 23 January 2017).
34. Hughes, J.D. *Shale Gas Reality Check*; Post Carbon Institude: Santa Rosa, CA, USA, 2015.
35. Featherston, W.; Jiang, B.; Drum, D.; O'Connor, M. NYT Shale Gas Allegations Seem Exaggerated. Available online: http://s3.amazonaws.com/zanran_storage/www.anga.us/ContentPages/2520050971.pdf (accessed on 23 January 2017).
36. Stevens, P. *Shale Gas in the United Kingdom*; Chatham House: London, UK, 2013.

37. Miller, S.M.; Wofsy, S.C.; Michalak, A.M.; Kort, E.A.; Andrews, A.E.; Biraud, S.C.; Dlugokencky, E.J.; Eluszkiewicz, J.; Fischer, M.L.; Janssens-maenhout, G.; et al. Anthropogenic emissions of methane in the United States. *Proc. Natl. Acad. Sci. USA* **2013**, *110*, 20018–20022. [CrossRef] [PubMed]
38. U.S. Energy Information Administration (EIA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013*; Energy Information Administration: Washington, DC, USA, 2015.
39. Howard, T.; Ferrara, T.W.; Townsend-Small, A. Sensor transition failure in the high flow sampler: Implications for methane emission inventories of natural gas infrastructure. *J. Air Waste Manag. Assoc.* **2015**, *7*, 856–862. [CrossRef] [PubMed]
40. Howard, T. University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure. *Energy Sci. Eng.* **2015**, *3*, 443–455. [CrossRef]
41. Allen, D.T.; Torres, V.M.; Thomas, J.; Sullivan, D.W.; Harrison, M.; Hendler, A.; Herndon, S.C.; Kolb, C.E.; Fraser, M.P.; Hill, A.D.; et al. Measurements of methane emissions at natural gas production sites in the United States. *Proc. Natl. Acad. Sci. USA* **2013**, *110*, 17768–17773. [CrossRef] [PubMed]
42. Allen, D.T.; Sullivan, D.W.; Harrison, M. Response to comment on "Methane emissions from process equipment at natural gas production sites in the United States: Pneumatic controllers". *Environ. Sci. Technol.* **2015**, *49*, 3983–3984. [CrossRef] [PubMed]
43. Balcombe, P.; Anderson, K.; Speirs, J.; Brandon, N.; Hawkes, A. *Methane and CO_2 Emissions from the Natural Gas Supply Chain: An Evidence Assessment*; Sustainable Gas Institute: London, UK, 2015.
44. Howarth, R.W.; Santoro, R.; Ingraffea, A. Methane and the greenhouse-gas footprint of natural gas from shale formations A letter. *Clim. Chang.* **2011**, *106*, 679–690. [CrossRef]
45. Stephenson, T.; Valle, J.E.; Riera-palou, X.; Global, S.; International, S.; Park, K.; Gs, R. Modeling the relative GHG emissions of conventional and shale gas production. *Environ. Sci. Technol.* **2011**, *45*, 10757–10764. [CrossRef] [PubMed]
46. O'Sullivan, F.; Paltsev, S. Shale gas production: Potential versus actual greenhouse gas emissions. *Environ. Res. Lett.* **2012**, *7*, 1–6. [CrossRef]
47. Zavala-Araiza, D.; Lyon, D.R.; Alvarez, R.A.; Davis, K.J.; Harriss, R.; Herndon, S.C.; Karion, A.; Adam, E.; Lamb, B.K.; Lan, X.; et al. Reconciling divergent estimates of oil and gas methane emissions. *Proc. Natl. Acad. Sci. USA* **2015**, *112*, 15597–15602. [CrossRef] [PubMed]
48. Karion, A.; Sweeney, C.; Pétron, G.; Frost, G.; Hardesty, R.M.; Ko, J.; Miller, B.R.; Newberger, T.; Wolter, S.; Banta, R.; et al. Methane emissions estimate from airborne measurements over a western United States natural gas field. *Geophys. Res. Lett.* **2013**, *40*, 4393–4397. [CrossRef]
49. Caulton, D.R.; Shepson, P.B.; Santoro, R.L.; Sparks, J.P.; Howarth, R.W.; Ingraffea, A.R.; Cambaliza, M.O.L.; Sweeney, C.; Karion, A.; Davis, K.J.; et al. Toward a better understanding and quantification of methane emissions from shale gas development. *Proc. Natl. Acad. Sci. USA* **2014**, *111*, 6237–6242. [CrossRef] [PubMed]
50. Peischl, J.; Ryerson, T.B.; Aikin, K.C.; Gouw, J.A.; Gilman, J.B.; Holloway, J.S.; Lerner, B.M.; Nadkarni, R.; Neuman, J.A.; Nowak, J.B.; et al. Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions. *J. Geophys. Res. Atmos.* **2015**, *120*, 2119–2139. [CrossRef]
51. Lavoie, T.N.; Shepson, P.B.; Cambaliza, M.O.L.; Stirm, B.H.; Karion, A.; Sweeney, C.; Yacovitch, T.I.; Herndon, S.C.; Lan, X.; Lyon, D. Aircraft-Based measurements of point source methane emissions in the barnett shale basin. *Environ. Sci. Technol.* **2015**, *49*, 7904–7913. [CrossRef] [PubMed]
52. Schneising, O.; Burrows, J.P.; Dickerson, R.R.; Buchwitz, M.; Bovensmann, H. Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations. *Earth's Future* **2014**, *2*, 548–558. [CrossRef]
53. ICF International for the US Environmental Defense Fund. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*; ICF International: Fairfax, VA, USA, 2014.
54. International Energy Agency. *Energy and Climate Change*; International Energy Agency: Paris, France, 2015.
55. Omara, M.; Sullivan, M.R.; Li, X.; Subramanian, R.; Robinson, A.L.; Presto, A.A. Methane emissions from conventional and unconventional natural gas production sites in the Marcellus shale basin. *Environ. Sci. Technol.* **2016**, *50*, 2099–2107. [CrossRef] [PubMed]
56. Mcjeon, H.; Edmonds, J.; Bauer, N.; Clarke, L.; Fisher, B.; Flannery, B.P.; Hilaire, J.; Krey, V.; Marangoni, G.; Mi, R.; et al. Limited impact on decadal-scale climate change from increased use of natural gas. *Nature* **2014**, *514*, 482–485. [CrossRef] [PubMed]

57. Rogner, H.-H.; Aguilera, R.F.; Archer, C.; Bertani, R.; Bhattacharya, S.C.; Dusseault, M.B.; Gagnon, L.; Haberl, H.; Hoogwijk, M.; Johnson, A.; et al. Energy resources and potentials. In *Global Energy Assessment—Toward a Sustainable Future*; Cambridge University Press: Cambridge, UK; New York, NY, USA; International Institute for Applied Systems Analysis: Laxenburg, Austria, 2012; pp. 423–512.
58. Mcglade, C.E. Uncertainties in the Outlook for Oil and Gas. Ph.D. Thesis, University College London, London, UK, 2013.
59. Gracceva, F.; Zeniewski, P. Exploring the uncertainty around potential shale gas development—A global energy system analysis based on TIAM (TIMES Integrated Assessment Model). *Energy* **2013**, *57*, 443–457. [CrossRef]
60. International Energy Agency. *Energy Technology Systems Analysis Programme Review of Resources and Trade of Fossil Energy Resources in the TIAM Model*; International Energy Agency: Paris, France, 2006.
61. Mcglade, C.; Ekins, P. The geographical distribution of fossil fuels unused when limiting global warming to 2 °C. *Nature* **2014**, *517*, 187–190. [CrossRef] [PubMed]
62. International Energy Agency. *World Energy Outlook 2011: Are We Entering a Golden Age of Gas*; International Energy Agency: Paris, France, 2011.
63. Thonhauser, G. Shale and tight gas development for Europe. In *Unconventional Gas: Potential Energy Market Impacts in the European Union*; European Commision—Joint Research Centre: Ispra, Italy, 2012; pp. 56–99.
64. Hilaire, J.; Bauer, N.; Brecha, R.J. Boom or bust? Mapping out the known unknowns of global shale gas production potential. *Energy Econ.* **2015**, *49*, 581–587.
65. Jacoby, H.D.; Sullivan, F.M.O.; Paltsev, S. The influence of shale gas on U.S. energy and environmental policy. *Econ. Energy Environ. Policy* **2012**, *1*, 37–52. [CrossRef]
66. Petak, K.R. Impact of natural gas supply on CHP deployment. In Proceedings of the U.S. Clean Heat & Power Association's Spring CHP Forum, Washington, DC, USA, 5–6 May 2011.
67. Gülen, G.; Browning, J.; Ikonnikova, S.; Tinker, S.W. Well economics across ten tiers in low and high Btu (British thermal unit) areas, Barnett Shale, Texas. *Energy* **2013**, *60*, 302–315. [CrossRef]
68. Loulou, R.; Labriet, M.; Kanudia, A. Deterministic and stochastic analysis of alternative climate targets under differentiated cooperation regimes. *Energy Econ.* **2009**, *31*, S131–S143. [CrossRef]
69. Gambhir, A.; Napp, T.; Hawkes, A.; Mccollum, D.; Fricko, O.; Havlik, P.; Riahi, K.; Drouet, L.; Bosetti, V.; Bernie, D. *Assessing the Challenges of Global Long-Term Mitigation Scenarios*; International Institute for Applied Systems Analysis (IIASA): Laxenburg, Austria, 2015; pp. 1–37.
70. United Nations Framework Convention for Climate Change. *Synthesis Report on the Aggregate Effect of the Intended Nationally Determined Contributions*; UNFCCC: Bonn, Germany, 2015; pp. 1–66.
71. O'Neill, B.C.; Kriegler, E.; Riahi, K.; Ebi, K.L. A new scenario framework for climate change research: The concept of shared socioeconomic pathways. *Clim. Chang.* **2014**, *122*, 387–400. [CrossRef]
72. Kriegler, E.; Weyant, J.P.; Blanford, G.J.; Krey, V.; Clarke, L.; Edmonds, J.; Fawcett, A.; Luderer, G.; Riahi, K.; Richels, R.; et al. The role of technology for achieving climate policy objectives: Overview of the EMF 27 study on global technology and climate policy strategies. *Clim. Chang.* **2014**, *123*, 353–367. [CrossRef]
73. Clarke, L.; Edmonds, J.; Krey, V.; Richels, R.; Rose, S.; Tavoni, M. International climate policy architectures: Overview of the EMF 22 international scenarios. *Energy Econ.* **2009**, *31*, S64–S81. [CrossRef]
74. U.S. Energy Information Administration (EIA). *International Energy Statistics*; Energy Information Administration: Washington, DC, USA, 2014.
75. United Nations Framework on Climate Change. *Adoption of the Paris Agreement*; UNFCCC: Bonn, Germany, 2015.
76. Fawcett, A.A.; Iyer, G.C.; Clarke, L.E.; Edmonds, J.A.; Hultman, N.E.; McJeon, H.C.; Rogelj, J.; Schuler, R.; Alsalam, J.; Asrar, G.R.; et al. Can Paris pledges avert severe climate change? *Science* **2015**, *350*, 1168–1169. [CrossRef] [PubMed]
77. Gambhir, A.A.; Napp, T.; Hawkes, A.; Winiwarter, W.; Purohit, P.; Wagner, F.; Bernie, D.; Lowe, J. *The Contribution of non-CO_2 Greenhouse gas Mitigation to Achieving Long-Term Temperature Goals*; IIASA: Laxenburg, Austria, 2015; pp. 1–27.