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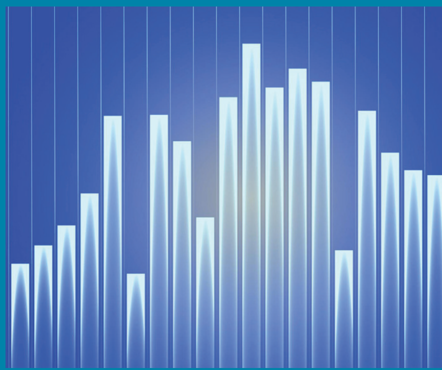

A Bridge to a Low-Carbon Future? Modelling the Long-Term Global Potential of Natural Gas

Research Report

A Bridge to a Low-Carbon Future? Modelling the Long-Term Global Potential of Natural Gas

Research Report

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Executive Summary

This project uses the global TIMES Integrated Assessment Model in UCL ('TIAM-UCL') to provide robust quantitative insights into the future of natural gas in the energy system and in particular whether or not gas has the potential to act as a 'bridge' to a low-carbon future on both a global and regional basis out to 2050.

We first explore the dynamics of a scenario that disregards any need to cut greenhouse gas (GHG) emissions. Such a scenario results in a large uptake in the production and consumption of all fossil fuels, with coal in particular dominating the electricity system. It is unconventional sources of gas production that account for much of the rise in natural gas production; with shale gas exceeding 1 Tcm after 2040. Gas consumption grows in all sectors apart from the electricity sector, and eventually becomes cost effective both as a marine fuel (as liquefied natural gas) and in medium-goods vehicles (as compressed natural gas).

We next examine how different gas market structures affect natural gas production, consumption, and trade patterns. For the two different scenarios constructed, one continued current regionalised gas markets, which are characterised by very different prices in different regions with these prices often based on oil indexation, while the other allowed a global gas price to form based on gas supply-demand fundamentals. We find only a small change in overall global gas production levels between these but a major difference in levels of gas trade and so conclude that if gas exporters choose to defend oil indexation in the short-term, they may end up destroying their export markets in longer term. A move towards pricing gas internationally, based on supply-demand dynamics, is thus shown to be crucial if they are to maintain their current levels of exports.

Nevertheless, it is also shown that, regardless of how gas is priced in the future, scenarios leading to a 2°C temperature rise generally have larger pipeline and LNG exports than scenarios that lead to a higher temperature increase. For pipeline trade, the adoption of any ambitious emissions reduction agreement results in little loss of markets and could (if carbon capture and storage is available) actually lead to a much greater level of exports. For LNG trade, because of the significant role that gas can play in replacing future coal demand in the emerging economies in Asia, markets that are largely supplied by LNG at present, we demonstrate that export countries should actively pursue an ambitious global agreement on GHG emissions mitigation if they want to expand their exports. These results thus have important implications for the negotiating positions of gas-exporting countries in the on-going discussions on agreeing an ambitious global agreement on emissions reduction.

The GHG mitigation polices that lead to the largest levels of future natural gas consumption are also examined. We find that up to 2020, the higher the CO_2 tax, the greater the level of gas consumption globally; however, by 2050, a CO_2 tax more commensurate with a 3°C temperature rise leads to the highest level of gas consumption observed in that year in any scenario. This global pattern is not observed in all regions, however, and indeed some countries such as Canada and India display very different behaviour. We further find that CCS has an important effect of increasing gas consumption, even at low imposed CO_2 tax levels.

Turning to the overall role of gas in a low-carbon future global energy system. In a scenario that provides a 60 per cent chance of limiting the mean surface temperature rise to 2°C, gas consumption rises until 2035 and indeed is larger than in a case with no GHG emissions reductions on a global level between 2015 and 2035. We therefore conclude that there is a good potential for gas to act as a transition fuel to a low-carbon future up to 2035. However, there are a number of important conditions to this result.

First, the bridging period is strictly time-limited. Global gas consumption declines in all years after 2035 whilst it continues to rise in scenarios leading to higher average temperature rises: any increase in near-term periods must be followed by a subsequent reduction in later periods.

Second, the absolute and relative increase in gas consumption (between the scenario limiting the temperature rise to 2°C and one with no GHG emissions reductions) must occur alongside a much greater reduction in coal consumption again in both absolute and relative terms. Further, gas is only a short-term complement to the much larger increase in low-carbon energy sources that must occur to replace the reduction in coal consumption and for the low-carbon transition actually to be achieved. Advocacy of gas as a transition fuel therefore needs a convincing narrative as to how global coal consumption can be curtailed and be replaced by low-carbon, non-gas energy sources.

Third, carbon capture and storage (CCS) is of particular importance. In a 2°C scenario in which CCS is not available, gas consumption peaked in 2025 and declined terminally thereafter: the role that gas can as a transition fuel play was thus substantially reduced.

Fourth, our definition of the bridging role that gas could play partly relies on to the difference in gas consumption between a 2°C scenario and a scenario with no GHG emission reduction policies. In this latter scenario there is a reversal of the trend that is currently being exhibited in many regions away from coal-based power generation and the average surface temperature rise in 2100 is around 4°C. If we were to compare gas consumption in the 2°C scenario with a scenario that results in a lower temperature rise, for example a 3°C scenario, then the advantage from a climate perspective conveyed by consuming additional gas is significantly lessened.

The fifth and final caveat is that this global pattern is not exhibited by all regions. Gas is able to play a bridging role in some regions but not in others. Of the 13 regions studied, gas had limited or no potential to act as a transition fuel in six (Africa, Canada, Central and South America, the Middle East and Mexico), a good potential in three (Australia, Other Developing Asia, and the United States), and a strong potential in four (China, Europe, India, and Japan and South Korea). Again this is dependent on the availability of CCS, with natural gas only remaining a strong bridge in China if CCS is not available.

Finally, we find that there is significant and widespread growth in shale gas production in the future, with little difference in production levels under different long-term emissions mitigation targets. However, this is sensitive to the availability of CCS, to the relative cost assumptions of shale gas compared with other conventional and unconventional sources, and to the levels of fugitive emission that occur during shale gas production. These latter two areas require significant further research before it can really be concluded that shale gas has an important role to play in the transition to a low-carbon global energy system.

Contents

	Executive Summary	
1.	Introduction	07
2.	Modelling Approach	09
3.	Scenarios Constructed	21
4.	Gas Price Development	27
5.	The Variation of Gas Consumption with GHG Mitigation	34
6.	The Role of Gas in a Low-Carbon Energy System	43
7.	Conclusion and Wider Implications for Gas Markets	54
8.	References	57
9.	Appendix	60

List of Tables

Table 1	List of regions and abbreviations used in this report in the 16 region TIAM-UCL model	10
Table 2	Percentage of gas lost in pipeline trnsport that is emitted as CO_2	16
Table 3	Pipeline capacity, length and cost data	17
Table 4	Assumed start and end locations within each region or pipelin name and estimated lengths of pipeline between these in brackets	18
Table 5	Assumed ports within each region for LNG liquefaction and re-gasification	19
Table 6	Estimated sailing distances between assumed ports within each region for LNG liquefaction and re-gasification in nautical miles	20
Table 7	Cost differentials added in the REGIONALGP scenarios	23
Table 8	Description of assumptions for the discrete emissions reduction scenarios	24
Table 9	CO_2 taxes that lead to the highest levels of regional gas consumption in different years and the CO_2 taxes in the 2°C and 3°C scenarios	39
Table 10	Gas consumption by region in a scenario in REF (in BCM/year)	44
Table 11	Absolute gas consumption by region in 2°C scenario including the dates on which regional consumption peaks and then declines terminally (all figures in Bcm/year)	49
Table 12	Absolute gas consumption by region in the 2°C scenario that does not allow CCS including the dates on which regional consumption peaks	49
Table 13	Criteria by which duration and magnitude of natural gas bridge in each region is judged	50
Table 14	Years to which natural gas acts as a bridge in 2°C scenarios, both in absolute terms and relative to REF, the percentage consumption is above REF at its maximum value, and therfore the potential role gas can play as a transition fuel in each region	50

List of Figures

Figure 1	Map of TIAM-UCL regions	10
Figure 2	Overview of TIAM-UCL Structure	11
Figure 3	Global supply cost curve for all gas split by category and region	14
Figure 4	Global supply cost curve for shale gas	14
Figure 5	Historical inter-regional pipeline trade between TIAM-UCL regions between 1998 and 2011	19
Figure 6	Annual average gas prices in the United States, UK and Japan	22
Figure 7	Examples of CO_2 taxes imposed and how these vary over time	23
Figure 8	Primary energy production and electricity production in REF_GLOBALGP	27
Figure 9	Breakdown of regional GHG emissions in REF_GLOBALGP	29
Figure 10	Gas production by category and region in REF_GLOBALGP	29
Figure 11	Shale gas production seperated by region in REF_GLOBALGP	30
Figure 12	Gas consumption by sector in REF_GLOBALGP	30
Figure 13	Gas traded by pipeline and LNG in REF_GLOBALGP	31
Figure 14	Net gas traded & regional gas prices from trading hubs in REF_GLOBALGP	31
Figure 15	Gas prices in REF_REGIONALGP and differences in gas price from REF_ GLOBALGP	32
Figure 16	Differences in gas production and consumption between REF_GLOBALGP and REF_REGIONALGP BALGP	33
Figure 17	The percentage of domestic gas production exported by Australia, the Former Soviet Union and Middle East in REF_REGIONALGP and REF_GLOBALGP	33
Figure 18	Changes to primary energy consumption and total electricity production in 2020, 2030 and 2050 under scenarios with CO_2 taxes that rise to between \$0/ tCO_2 and \$500/tCO_2 in 2050	36
Figure 19	Global gas consumption over time under different CO_2 tax scenarios	37
Figure 20	Global gas consumption at different CO_2 tax levels for different years	37
Figure 21	CO_2 taxes that maximise global gas consumption and the CO_2 taxes in the 2°C and 3°C scenarios	37
Figure 22	Differences in gas consumption when CCS is and is not permitted	39
Figure 23	Total gas traded by pipeline and LNG under different emissions mitigation and market structure assumptions	40
Figure 24	Global gas consumption and changes relative to REF	45
Figure 25	Global gas consumption in 2DS by sector and differences with REF	45
Figure 26	Primary energy consumption in 2DS, and changes relative to REF	46
Figure 27	Percentage changes in coal and gas consumption in 2DS relative to REF	46
Figure 28	Primary energy consumption in 2DS, and changes relative to REF	47
Figure 29	Absolute gas consumption by region in 2DS, and changes between 2DS and REF	48
Figure 30	Absolute gas consumption by region in 2DS_noCCS, and changes between this scenario and REF	48
Figure 31	Global shale gas production in each scenario and projections from the latest IEA New Policies Scenario	51

Introduction

1

The 'shale gas revolution' (Stevens 2012) has had profound impacts on the outlook for natural gas. Indeed many analysts and organisations now view natural gas as an attractive 'bridge' to a low carbon energy system (IPCC WGIII 2014; Stephenson *et al.* 2012). This report aims to explore potential roles for natural gas in the future global energy system out to 2050 and investigates in particular the global and regional carbon implications of the 'profound revolution going on in gas' (Helm 2011).

Whether the widespread use of natural gas will increase or reduce greenhouse gas (GHG) emissions is dependent on whether it adds to existing and projected demand for fossil fuels (e.g. perhaps by lowering the overall price of fossil fuels), substitutes for higher-carbon fossil fuels (e.g. coal or oil), or substitutes for lower-carbon or zero-carbon energy sources (e.g. nuclear or renewables). At the same time, any explicit attempt to reduce GHG emissions can be expected to impact global and regional levels of gas production and consumption as well as having major implications for existing trade relationships. For example, any demand destruction for gas brought about by attempts to reduce emissions in some regions, which would be accompanied by a fall in prices, may result in increased consumption in others (and vice versa).

These relationships are further complicated by a number of recent, more geopolitical, events that are having a strong influence on projections of future gas demand. The disaster at the Fukushima Daiichi nuclear power plant led not only to an immediate and significant increase in Japanese liquefied natural gas (LNG) demand, but also to a number of countries re-evaluating the role nuclear power in their future energy systems. There was hence an increased demand for alternative sources of energy (notably coal and gas) in these countries. Conversely, the removal of President Yanukovych in Ukraine, and subsequent actions by Russia, has led to a renewed determination in Europe to drive down gas demand to reduce reliance on Russian gas supplies.

The interaction between changes in gas consumption and GHG emissions can therefore be expected to vary markedly between different regions, under different global emission reduction targets, as well as depending on the development of different technologies (particularly carbon capture and storage).

To date, a number of studies have examined the potential for gas to act as a 'bridge' or 'transition fuel' in the United States (see e.g. Moniz *et al.* 2010). However, the potential role of natural gas on both a global and regional basis, outside of the United States, remains unclear. In this project, we therefore use the global TIMES Integrated Assessment Model in UCL ('TIAM-UCL') to provide robust quantitative insights into this issue for the first time.

1.1 Research questions

TIAM-UCL has previously been used for a number of reports focussing on future projections of the energy system under varying degrees of GHG emissions reduction (e.g. Anandarajah *et al.* 2013; Anandarajah & McGlade 2012; Kesicki & Anandarajah 2011). GHG emissions are clearly central to this project also, but given the focus of this project it is useful to understand in detail how natural gas and gas markets are modelled in TIAM-UCL. We therefore address two additional questions to highlight these factors. We focus on the transition of the energy system and the supply and demand of commodities out to the year 2050.

The three key research questions that are addressed in this project are:

1. How do different gas market structures affect natural gas production, consumption, and trade patterns?
2. What are the conditions and policies that lead to the largest levels of future natural gas consumption?
3. What are the conditions under which natural gas can play a role as a 'bridging fuel' to a low-carbon energy system?

The remainder of this report can be differentiated into two principal parts. The first, incorporating Sections 2 and 3, describes in detail the model and a number of the modelling assumptions made in this work. It will likely be of most interest to energy analysts and modellers who want to know the details of the model formulation and the way in which the results have been derived. The second part, incorporating Sections 4 to 7, sets out the results of the scenarios implemented and the policy implications that can be drawn. It will likely be of most interest to energy and gas policy analysts and makers and those interested in the interaction of gas with the climate agenda.

Modelling Approach

2

2.1. Overview of TIAM-UCL

The TIMES Integrated Assessment Model in UCL ('TIAM-UCL') is a technology-rich, bottom-up, whole-system model that minimises energy system cost, or maximises social welfare (as explained further below) under a number of imposed constraints. It models all primary energy sources (oil, gas, coal, nuclear, biomass, and renewables) from resource production, trade, conversion, and sectoral end-use.

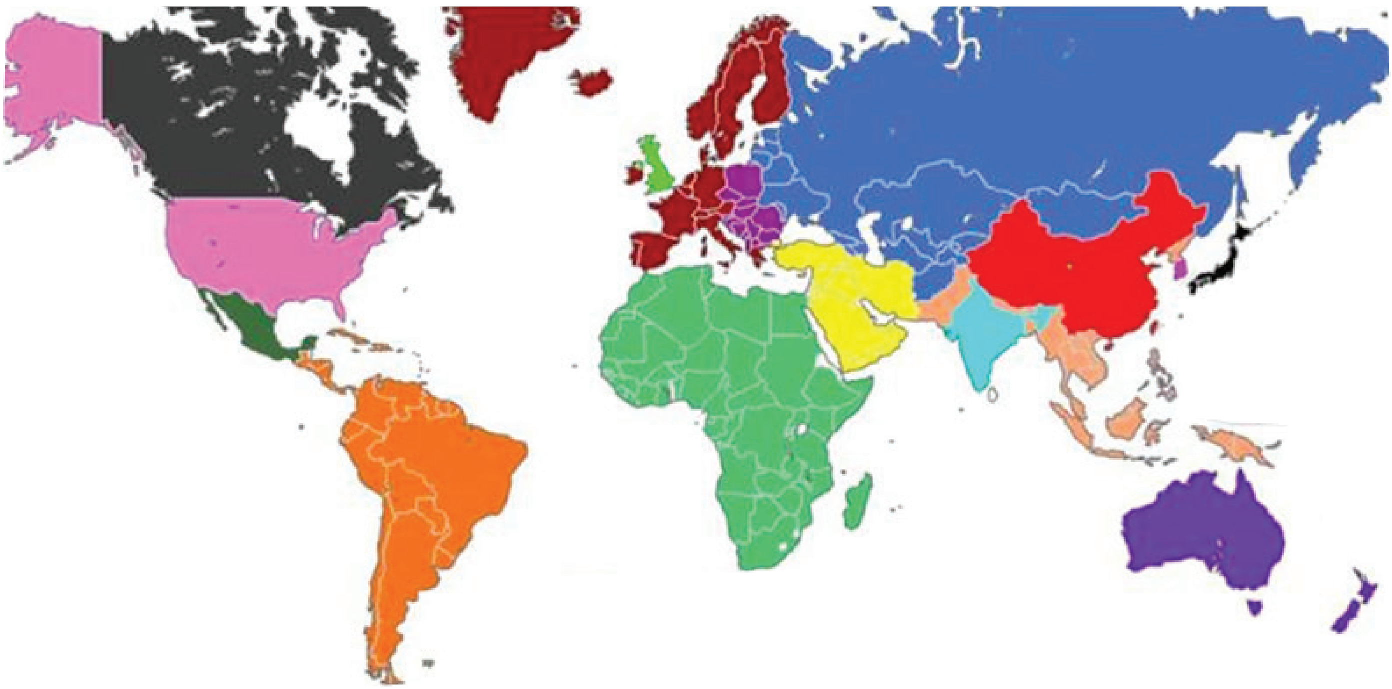
TIAM-UCL is based on the ETSAP-TIAM model, a linear programming, partial equilibrium energy system model developed and maintained by the IEA's Energy Technology Systems Analysis Programme ('ETSAP') (Loulou & Labriet 2007). The 16-region TIAM-UCL model, developed under the UK Energy Research Centre (UKERC) Phase II, has broken out the UK from the previous Western Europe region in the 15-region ETSAP-TIAM model to allow more specific analysis of the UK in a global context.

The 16 regions in TIAM-UCL are shown in Figure 1, with their names and regional abbreviations presented in Table 1. For clarity, in much of the analysis that follows, we aggregate some of these regions together. The proportions of existing (as of 2011) electricity generation and primary energy supply that are coal, oil, gas, nuclear and renewables within each of the regions are outlined in the appendix.

Table 1. List of regions and abbreviations used in this report in the 16 region TIAM-UCL model

Region	Abbreviation
Africa	AFR
Australia and New Zealand	AUS
Canada	CAN
Central and South America	CSA
China	CHI
Eastern Europe	EEU
Former Soviet Union	FSU
India	IND
Japan	JAP
Mexico	MEX
Middle East	MEA
Other Developing Asia	ODA
South Korea	SKO
United Kingdom	UK
United States	USA
Western Europe	WEU

Figure 1. Map of TIAM-UCL regions



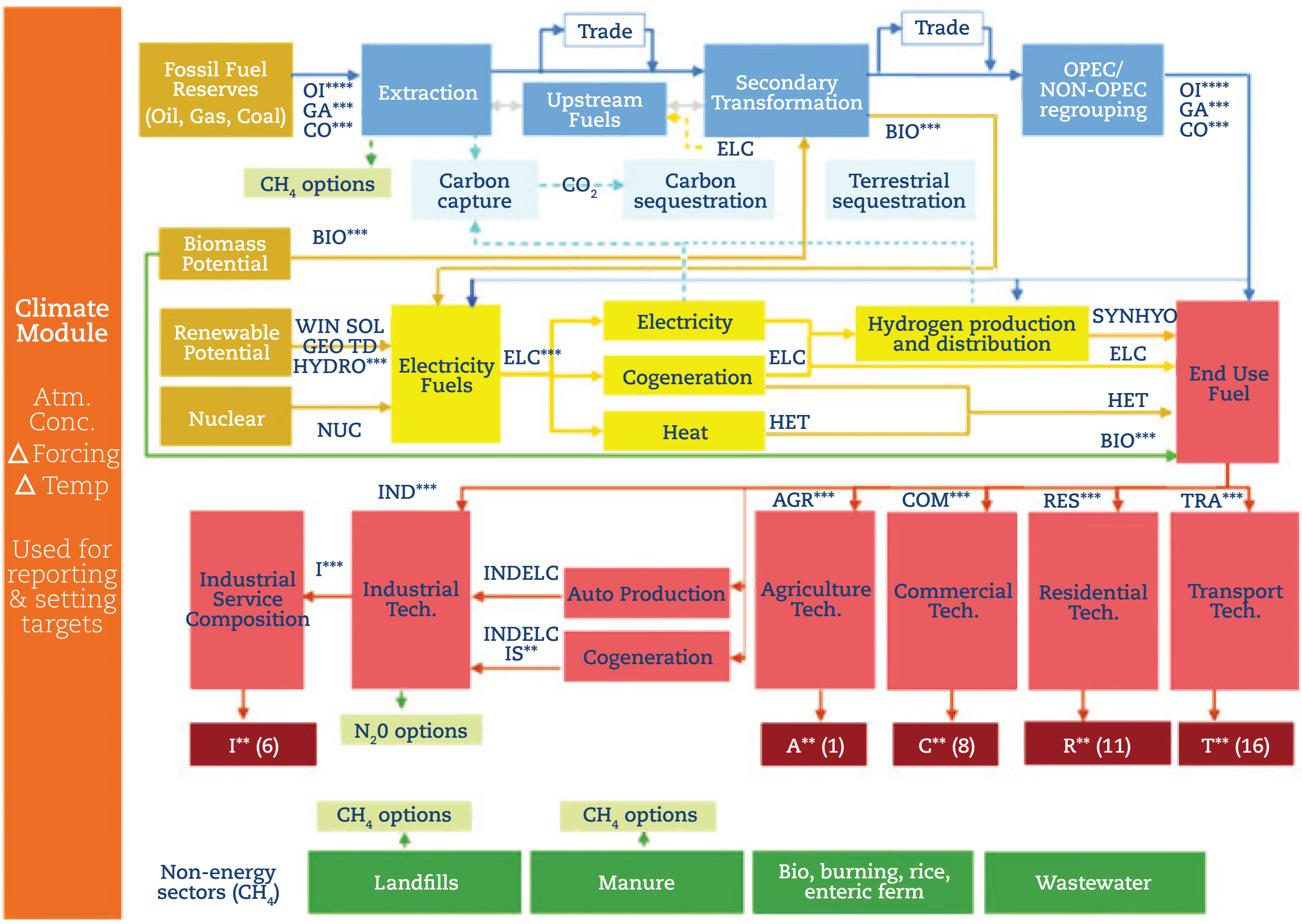
TIAM-UCL is a ‘demand-driven’ model. This means that the model must ensure that all energy service demands (such as tonnes of production of iron and steel or billion passenger vehicle kilometres) within all regions are met either by using energy conversion devices and technologies or by reducing service demand. There are a total of 43 energy service demands included in TIAM-UCL, split between the transport (with 14 individual energy service demands), residential (10), industrial (10), commercial (8) and agricultural (1) sectors.

These energy service demands are exogenously specified and are initially derived within each region by calibrating to actual 2005 levels using the IEA Extended Energy Balances of OECD and non-OECD countries (IEA 2013a). Future demand is then projected based on an assumed relationship of each energy service demand with exogenously specified rates of: regional GDP growth, regional population growth, GDP/capita, household sizes, or, for industry-sub sectors, sectoral contributions to GDP. These drivers have been presented in previous reports (Kesicki & Anandarajah 2011; Anandarajah & McGlade 2012) and more information is available online and in Anandarajah *et al.* 2011.

The objective of TIAM-UCL is to minimise the total discounted energy system cost in the standard version or maximise societal welfare (the sum of consumer and producer surplus) in the elastic demand version. The model therefore chooses the cost-minimising (or surplus maximising) combination of technologies and commodities that mean that that all end-use demands are met, while ensuring that all other constraints (such as keeping GHG emissions below a certain level) are not exceeded. Figure 2 presents a schematic of the energy flows in TIAM-UCL that can be used to satisfy the energy service demands.

The costs of all production, trade, conversion, infrastructure and end-use technologies are specified separately within each region in the model. The reserve and resource potential of all primary energy sources, such as the extraction of oil or gas or the production of bio-crops, are taken into account through annual or cumulative bounds

Figure 2. Overview of TIAM-UCL Structure



(depending on whether or not the sources are renewable). These assumptions for natural gas are discussed in more detail in Section 2.3 below. All commodity prices and how these change over time are generated endogenously by the model.

For all the scenarios run in this project, a 'reference' or 'base case' is first formed that incorporates no GHG emissions abatement requirements. This base case uses the standard version of the model that relies upon minimising the discounted system cost: this is used to generate base 'supply prices' for each energy service demand in the model. These supply prices are the marginal costs, including commodity and technology costs, of meeting the demands. For the GHG abatement scenarios, constraints are introduced and the model then re-run using the elastic-demand version. This version of the model maximises social welfare and allows the energy service demands to respond to changes in the supply prices that result from these new constraints. All scenarios in this project are run with perfect foresight.

The base year of TIAM-UCL is 2005, and so all costs and prices reported in this report are in US$2005 unless otherwise noted. The total discounted energy system cost relies upon a social discount rate of 3.5 per cent discounted back to this base-year (HM Treasury 2003).

The energy system portion of the model is run in five-year increments up to 2050 and ten-year increments thereafter up to 2100, however the climate module (see Section 2.2) alone continues out to 2200. An advantage of using a long-term energy system model is that it is possible to run the model for much longer periods than reported in results: path dependency means that costs and emissions reductions after the final date for which results are reported will affect results prior to that date. This allows the model to take into account the long-term implications of 'locking in' various energy system configurations, such as the near-term investment in new coal or gas power infrastructure.

2.2 Greenhouse gas accounting and climate module

The relationships between changes in GHG emissions, changes in atmospheric concentrations of these gases, changes in radiative forcing, and the change in temperature of the earth's climate are extremely complex. Solving the equations that aim to represent and capture these relationships is difficult and requires huge computing power. Since TIAM-UCL is an energy systems model and not a climate model these complex equations are simplified significantly.

The climate module in TIAM-UCL is therefore calibrated to the MAGICC climate model (Meinshausen *et al.* 2011). This module contains simplified equations that model the concentrations of three different GHGs with strong global warming potential: carbon dioxide (CO_2), methane (CH_4) and Nitrous oxide (N_2O). The module tracks the accumulation of anthropogenic emissions in the atmosphere and calculates the change in radiative forcing resulting from the modification of atmospheric concentrations of these GHGs. Finally, on a global scale, the climate module can calculate the realised temperature change resulting from the change in radiative forcing.

MAGICC provides the 60 per cent probability of long-term stabilisation at average surface temperature rises. In this project, the climate module is used to constrain the model to certain bounds on temperature rise, and so these will also correspond to a 60 per cent probability of being achieved.

For example, policy makers have agreed that the global average surface temperature should not exceed 2°C over the long-term (UNFCCC 2012; UNFCCC 2009). In many of the scenarios below we therefore constrain the model to ensure that the temperature rise by 2200 (which we interpret here to be the 'long-term') is not greater than 2°C. In these scenarios there is therefore around a 60 per cent probability that the global average surface temperature will be below 2°C and a 40 per cent probability that it will be above 2°C. These probabilities should not be interpreted too rigidly, however. There are other GHGs apart from CO_2, CH_4 and N_2O, such as F-gases and volatile organic compounds (VOC's), which are not explicitly modelled within TIAM-UCL, and, as noted, the climate module is a much simplified version of the climate system.

In the following scenarios, GHG (i.e. both CO_2 and non-CO_2) emissions are generally constrained on a global level. A further assumption is that GHG emissions permits can be traded between any region in the model from 2020 onwards[1]. This means that there is a truly global effort to reach the required level of emission reduction, with the model always choosing the most cost effective region in which to reduce emissions. Since the model endogenously generates the marginal cost of mitigating CO_2, equivalent to a CO_2 tax commensurate with a certain level of emissions reduction, in this situation there would be a single, global price of CO_2.

This situation contrasts with exogenously imposing regional reduction targets and not allowing emissions trading. In this case regions would effectively be acting in competition for low-carbon commodities, there would be regionally different CO_2 prices reflecting the cost or ease of reaching the required levels of emissions reduction, and overall energy system costs would be higher[2]. We use the former of these two approaches as we are interested in the most cost effective manner in which to limit the temperature target to 2°C (or other levels as discussed below).

2.3 Modelling natural gas in TIAM-UCL

2.3.1 Gas production

There are a total of eight categories of 'conventional' and 'unconventional' gas modelled in TIAM-UCL: current conventional proved and probable (2P) reserves that are in fields in production or are scheduled to be developed, reserve growth, undiscovered gas, Arctic gas, associated gas, tight gas, coal-bed methane, and shale gas. Here, the latter three of these are collectively referred to as the unconventional gases (McGlade *et al.* 2013b).

Reserve growth is defined to be 'the commonly observed increase in recoverable resources in previously discovered fields through time' (Klett & Schmoker 2003). Quantities in this category include any contributions from: reserves in fields that have been discovered but are not scheduled to be developed (often called 'fallow fields' or 'stranded gas'), the implementation of new advanced production technologies, changes in geological understanding, and changes in regional definitions.

Tight gas is gas trapped in relatively impermeable hard rock, limestone or sandstone, coal-bed methane is gas trapped in coal seams that is adsorbed in the solid matrix of the coal, and shale gas is gas trapped in the fabric of fine-grained shale.

Each of the above categories is modelled separately within the regions listed in Table 1. The resources and costs of gas extraction are also specified separately for members of the Organisation of Petroleum Exporting Countries (OPEC) within each relevant region giving a total of 19 regions for which resources and production costs are specified.

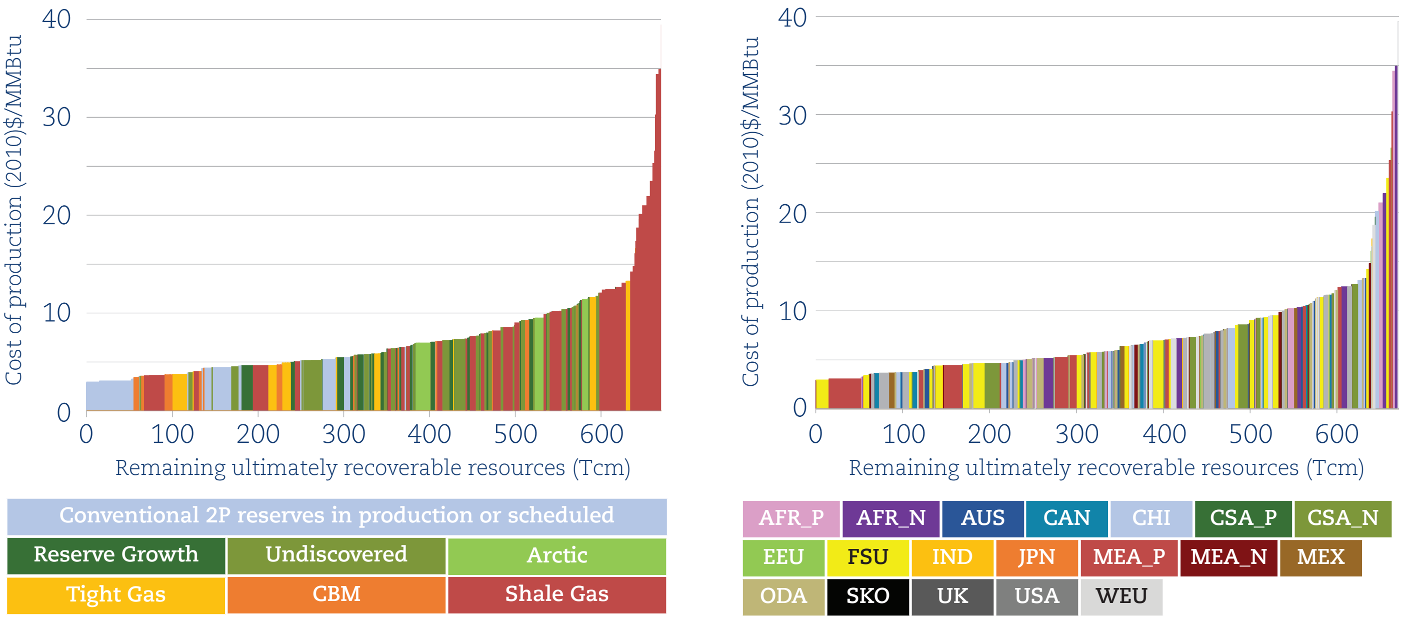
The reserve and resource volumes and costs have been derived as described in detail in McGlade (2013). Briefly, they rely on the construction of individual supply cost curves within each region for each of the eight categories listed above. These are then converted into three 'cost elements', each with a weighted-average cost of the resource they comprise, for input into TIAM-UCL. Figure 3 displays the overall global supply curves for all sources of gas that are included in TIAM-UCL, and Figure 4 the 'cost elements' for shale gas, separated by region. Associated gas is modelled as a by-product of crude oil but cumulative constraints are imposed on its availability. The model is free to choose whether or not to develop crude oil fields with or without associated gas[3]. Sour gas and deepwater gas are modelled as part of the conventional resources and are available at higher costs: these tend therefore to increase the average costs of the resource elements for each category. Regional gas prices are generated endogenously within the model. These incorporate the marginal cost of production, scarcity rents and rents arising from other imposed constraints, and transportation costs.

A new key aspect of TIAM-UCL recently introduced is the imposition of asymmetric constraints on the rate of production of oil and gas given a certain level of resource availability. These are intended to represent 'depletion rate constraints'.

[1] If only a single, global target to mitigate emissions is imposed, there is no need to trade emissions permits between regions as they are all working in conjunction. This assumption is therefore only important if there are individual regional emission reduction constraints imposed as these regions would need to mitigate domestically. For some of the scenarios discussed in Section 3.3, region-specific emissions reductions are introduced up to 2015, following the pledges made as part of the Copenhagen Accord.

[2] This is true unless the regional targets chosen happen to match exactly the regional levels of emissions reduction that the model endogenously selects when imposing the global emissions reduction target.

Figure 3. Global supply cost curve for all gas split by category and region



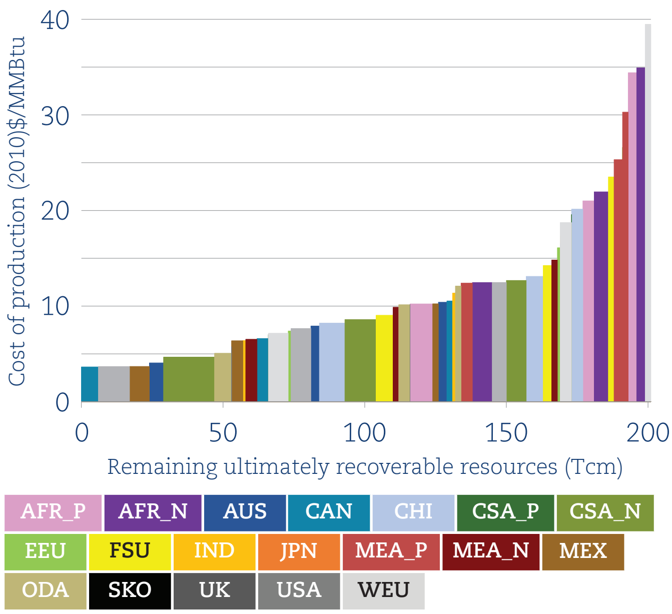
Source: McGlade (2013)
Note: '_N' and '_P' suffixes are the resources in Non-OPEC and OPEC countries within each relevant region. JPN and SKO have negligible resources.

In TIAM-UCL, they are modelled through introducing maximum annual production growth and maximum 'decline rate' restrictions. They are imposed on each cost element of each category of gas in each region, and ensure that the production follows a more realistic profile over time.

In each region, production of each cost element of each category of gas can initially increase in any given five year period at a maximum value of 0.5 to 1 per cent of the total resource potential of that element (this is called the 'seed value'). This is subsequently allowed to double every two years. Slower rates of increase are obviously allowed if desired but this describes the maximum rate at which production can grow over time.

Decline rates are defined to be 'how rapidly the production from different categories of field is declining and how this may be expected to change in the future' (Sorrell *et al*. 2012). The decline rate constraints introduced into TIAM-UCL are slightly more complex. When measuring the average decline rate for a group of fields, it is important to distinguish between: (i) the 'overall' or 'observed' decline rate, (ii) the 'post-peak' decline rate, and (iii) the 'natural decline rate'.

Figure 4. Global supply cost curve for shale gas



Source: McGlade (2013)

[3] Associated gas is however included in Figure 3 for illustrative purposes so that the fully resource potential is displayed. In this figure, it is assigned the costs of the resource to which it most closely corresponds in each region: for example associated gas reserves in the UK are assigned the costs of UK gas reserves.

The observed decline is the decline in production seen in all currently producing fields including those that have yet to pass their peak. The post-peak decline refers to the decline seen just from the subset of fields that are themselves in decline. Finally, the natural decline is the rate at which production from any field would decline in the absence of any additional capital investment.

The increases in production from new capital investment for a particular resource in a particular region are determined endogenously within TIAM-UCL and so the 'natural' decline rate is the most appropriate to use to specify production constraints in TIAM-UCL.

Natural decline rates were generated for each region as described by McGlade (2013) and are specified as constraints in TIAM-UCL in the form of equal maximum annual reductions. This results in compound decline over time. For example, say the decline rate of a given region is 4 per cent. In a ten year period, production can fall to no more than 66 per cent of its initial production ($1\text{-}0.96^{10}$ = 66 per cent). The model is free to choose to decline at less than the specified rate or to grow production (subject to the growth constraint). It can do so, however, only if the resource remaining after any increase is sufficient to allow it to decline at no greater rate than the specified maximum in each subsequent year over the remaining time horizon. These growth and decline constraints are imposed on each resource element of each category of gas within each region.

Estimates of shale gas decline rates are currently a source of controversy, with some commentators suggesting that future decline rates have been underestimated, i.e. that production from shale gas wells is declining at a faster rate than assumed by many analysts (Berman & Pittinger 2011; Berman 2010). An extended discussion of this issue is provided in McGlade *et al.* (2013a), but it is nevertheless generally accepted that production from shale gas wells (and the other two unconventional sources) declines at a much faster rate than conventional wells. For example, within one year production from shale gas wells can decline by around 50 per cent from the levels seen in the first month or so, while decline rates for conventional sources tend be closer to around 5 per cent every year (IEA 2009). For the modelling of the depletion rate constraints within TIAM-UCL, we therefore assume different decline rates between conventional and unconventional gas.

2.4 Gas Trade

The gas trade module of TIAM-UCL specifies the costs, efficiencies, associated emissions and constraints of the trading of gas by both pipeline and liquefied natural gas (LNG). This has been substantially revised as part of this project. This section contains the assumptions and sources behind these modifications; these have been made in conjunction with, and to reflect the findings of, the UK Energy Research Centre project on Global Gas Security (see **www.ukerc.ac.uk/support/RF3LGasSecurity**).

2.4.1 Pipeline

Pipeline trade is not a perfectly efficient transport mechanism and gas is lost while it is being transported by two mechanisms. First, compressor stations are located at various intervals along a pipeline to maintain pressure to allow the efficient flow of gas.

These, for example, reduce surface tension with the inside of the pipe, or allow the gas to flow uphill. Compressor stations require electricity to operate, and the majority of this is generated by extracting and combusting a proportion of the through-flow of gas. Any such gas will obviously be lost and results in some CO_2 emissions.

Second, some gas is leaked during transport. Leaks occur both as gas is flowing through compressor stations, and by accident along pipelines as it is being transported. Research indicates that it is the former of these that accounts for the majority of the vented emissions (Picard 2000; IEA 2006). Any gas lost by either of these mechanisms will result in CH_4 emissions to the atmosphere. Consequently, the quantity of gas entering a pipeline will not equal the volume exiting; with some losses to CO_2 (from use in compressor stations) and some to CH_4.

This section therefore briefly sets out the assumptions and data sources used to estimate gas lost in pipeline transport, and the proportion of this that is emitted as CO_2 and as CH_4. This is done separately for intra-regional and longer-range inter-regional transport.

The IEA (2013a) provides data on the volumes of gas lost in transit in 2010 within regions. If these values are divided by the volumes that are produced (also provided), this yields an estimate of the percentage of gas produced that is lost in intra-regional transmission and distribution. Examples are 3.2 per cent in the United States and 7 per cent in the former Soviet Union.

Table 2. Percentage of gas lost in pipeline transport that is emitted as CO_2

Pipeline number	Number of stations	Total power capacity (MW)	Total throughout (mcm/day)	MW/(mcm/d)
1	123	1,091	1,978	0.55
2	326	4,049	9,055	0.45
3	195	1,989	3,763	0.53
4	164	1,428	2,464	0.58
5	90	1,149	2,389	0.48
6	49	668	1,236	0.54
7	93	1,199	2,419	0.50
8	25	181	333	0.54
9	4	35	48	0.72
10	43	358	628	0.57
11	89	440	658	0.67
			Average	0.56 MW/(mcm/d.comp)
			150 km compressor spacing	3.7E-03 MW/(mcm/d.km)
			Power required (Khalaji 2012)	4.8E-03 MW/(mcm/d.km)
			At 38% compressor efficiency	2.3E-05 per cent gas lost/km

Source: Manipulation of EIA (2007) data

Estimates for inter-regional transport figures are slightly more complex, however. The first aim is to estimate the percentage of gas lost per km per unit volume flowing through large-scale pipelines. This can then be converted into a total percentage loss by multiplying it by assumed lengths of pipelines between regions (also set out below).

This first step focuses on compressor stations. The EIA (2007) provides data on the electricity requirements of compressor stations on eleven transmission pipelines within the United States. These data, and how they are manipulated, are summarised in Table 2. To summarise, each compressor is estimated to require 0.56 MW electricity per million cubic metres (mcm) flowing through each day. By assuming that there is one compressor station every 150 km (NETL 2012), and an electrical conversion efficiency of 38 per cent (from the IEA 2006)[4], it can be estimated that around 2.28×10^{-5} per cent of gas entering a pipeline is lost for every kilometre it travels. As mentioned above this is emitted as CO_2, and is converted at 2.1 ktCO_2 per mcm gas consumed.

Regarding gas lost as CH_4, NETL (2012) indicates that based on EPA emission data from 2003 in the USA, the volume lost both from operations at compressor stations and as the gas flows along the pipelines (i.e. through accidental leaks), is 5.4×10^{-6} per cent/km of pipeline. Gas lost in this way results in 678 tCH_4 per mcm gas vented. Taken together, a total of 2.82×10^{-5} per cent of gas entering a pipeline is therefore lost for every km it travels.

The next stage is to estimate the costs of constructing and operating new pipelines. Cobanli (2014) provides length, capacity, and cost estimates for a number of pipelines, which are set out in Table 3. To this we have added the recent Nordstream pipeline (Chyong *et al.* 2010). Trade process costs in TIAM-UCL are calculated per unit of gas transported, and we convert our estimate to an average cost per km and per unit of gas, giving $335/mcm.km (in 2005$). Operating costs are simply assumed to be 2 per cent of the capital investment per year (Core Energy Group 2012), with each pipeline assumed to have a lifetime of 40 years.

[4] We have taken the average compressor efficiency from OECD countries and apply this to all transmission pipelines regardless of start and end region. This relies upon the assumption that both existing and new long range transmission pipelines will rely upon more efficient compressor stations rather than take the current average efficiency, which is generally somewhat lower.

Table 3. Pipeline capacity, length and cost data (Cobanli 2014; Chyong *et al.* 2010)

Route	Status	Capacity (Bcm/year)	Length (km)	Cost (2005$ billion)	$/(mcm.km)
South Stream	Proposed	63	900	17	300
TTP	Extension	15	2775	11	265
Trans Caspian	Proposed	20	300	4	670
Nabucco-West	Cancelled	10	1329	6	440
Trans Adriatic (TAP)	Proposed	10	867	4	450
Trans Anatolian (TANAP)	Proposed	16	2000	6	180
Turkmenistan-China	Operational	30	1833	11	200
Nordstream	Operational	55	1222	17-21	254-310
				Average	384

To provide an example, consider a 2000 km pipeline transporting 30 Bcm/year. The above assumptions input to TIAM-UCL would be that capital costs are $20 billion and the operating costs $400 million/year. A total of 5.6 per cent of the gas transported (1.7 billion cubic metres (Bcm)) would be lost every year. Of this, 1.4 Bcm would be combusted and result in 2,900 ktCO_2 and the remainder (0.3 Bcm) would be vented, resulting in 220 ktCH_4. Total GHG emissions would therefore be around 8.5 MtCO_2e.

The next stage is to estimate viable pipeline routes between different regions and reasonable distances for these. These are shown in Table 4 for each of the 16 regions given previously in Table 1; if there is no entry in a row or column then pipeline trade is not possible between these regions.

A final variable that needs to be estimated for pipeline trade is any constraints on the construction of new pipelines. The most transparent manner in which to impose such a constraint is to examine historical rates of increase in trade between regions and use this to set a maximum limit on the rate at which new pipelines can be constructed. Figure 5 thus shows the increases in inter-regional pipeline trade over the past 13 years, with negative figures indicating imports and positive figures exports. Note that this is not net trade, rather the total volumes either entering or exiting each of the regions by pipeline. Build-rate constraints within TIAM-UCL can be imposed either as a maximum annual percentage increase (which was used for the constraining the growth of production of natural gas as discussed in Section 2.3.1) or as a maximum absolute increase within a 5-year period. For pipeline trade, a maximum absolute increase is likely a more appropriate constraint since investments tend to be on a large-scale basis rather than incremental.

Figure 5 shows that the largest increase in either imported or exported gas in any region in any 5-year period is 36 Bcm (exports from the Former Soviet Union (FSU) between 2006 and 2011). This is therefore used as the maximum increase in pipeline trade in any 5-year period between any regions and effectively means that a maximum of one new 36 Bcm pipeline can be constructed every 5 years for any of the pipelines given in Table 4. It is also worth noting that a proposed deal between Russia and China on pipeline gas (see e.g. Mazneva 2014) would add 38 Bcm of trade between these two countries over a similar timeframe and so is in line with the constraint used here.

2.4.2 Liquefied Natural Gas

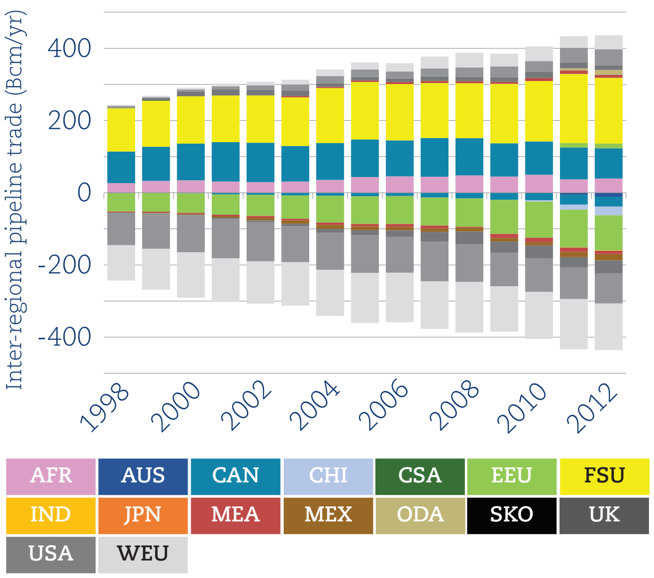
Transport of gas as Liquefied Natural Gas (LNG) involves three steps – liquefaction, transport and re-gasification. Liquefaction is an energy intensive process as it requires the gas to be cooled to 162°C (-260°F) to become a liquid. The gas flowing to the facility is generally used to provide this energy and as a result around 11 per cent of the gas is consumed during liquefaction (Herrmann *et al.* 2013), although this percentage does vary seasonally and regionally due to differences in ambient temperatures. Since this gas is used as a feedstock fuel, the resultant emissions are CO_2.

Construction of LNG liquefaction terminals is also very expensive, with their capital costs having increased markedly in recent years from $0.3bn/million tonnes (Mt) LNG capacity in 2000 to $1.2bn/Mt in 2013 (Songhurst 2014). For simplicity, we assume a single figure slightly below the peak cost within all regions of $1bn/Mt of LNG capacity; this is similar to the figure given by Herrmann *et al.* (2013), and is equivalent to around $0.7/m^3 natural gas liquefied (after losses).

Table 4. Assumed start and end locations within each region or pipeline name and estimated lengths of pipeline between these in brackets. Rows and columns are exporting and importing regions respectively.

	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	UK	USA	WEU
AFR																Algeria -Spain (747)
AUS																
CAN															Alliance (1560)	
CHI													via NK (3200)			
CSA																
EEU																(FSU-EEU) minus (FSU-WEU (297)
FSU				Central Asia-China (1833)		Torzhok-Poland (925)						(1500)	Sakhalin via NK (5082)			Nord Stream (1222)
IND																
JPN																
MEA						Southern corridor (3893)		via Pakistan (3300)				Qatar-Pakistan (1760)				
MEX															Monterrey - Texas (334)	
ODA																
SKO																
UK																Interconnector + VTN-RTR (496)
USA		Vector (800)									Eagle ford-Monterrey (334)					
WEU														Langeled (1166)		

Figure 5. Historical inter-regional pipeline trade between TIAM-UCL regions between 1998 and 2011



Source: BP Statistical Review (1998-2013)

Table 5. Assumed ports within each region for LNG liquefaction and re-gasification.

	Liquefaction	Re-gasification
AFR	Algeria (Skikda)	Algeria (Skikda)
AUS	Australia (Dampier)	Australia (Dampier)
CAN	Canada (Kitimat)	Canada (Canaport)
CHI	China (Fujian)	China (Fujian)
CSA	Trinadad & Tobago (Point Fortin)	Argentina (Bahia Blanca)
EEU	Poland (Swinoujscie)	Poland (Swinoujscie)
FSU	Russia (Sakhalin)	Russia (Sakhalin)
IND	Indonesia (Dahej)	Indonesia (Dahej)
JPN	-	Japan (Sodegaura)
MEA	Qatar (Ras Laffan)	Kuwait (Mina Al Ahmadi)
MEX	Mexico (Ensenada)	Mexico (Ensenada)
ODA	Malaysia (Bintulu)	Thailand (Map Ta Phut)
SKO	-	South Korea (Inchon)
UK	-	UK (Milford Haven)
USA	USA (Sabine)	USA (Sabine)
WEU	Norway (Melkoya)	Belgium (Zeebrugge)

Re-gasification facilities are less expensive and less energy intensive, and Herrmann *et al.* (2013) indicate that they cost \$200mn/Mt of LNG capacity (around \$0.1/m^3 natural gas processed) and consume 1 per cent of the gas received – this is again released as CO_2.

Seaborne LNG is a much more flexible trade process than pipeline trade since it can be used over longer distances and between any regions. Consequently there are many more possible trade routes. Table 5 summarises the locations of the liquefaction and re-gasification facilities assumed in each region in TIAM-UCL, and Table 6 calculates sailing distances between each. The liquefaction and re-gasification terminals are not necessarily the same in each region. Again if there is no entry in row or column then trade is not possible between these.

These distances are important not only from a cost perspective but also because some of the gas that is being transported 'boils-off' from the LNG ship and is lost. In general (particularly at present with such a large price differential between gas and heavy fuel oil) this is used to power the ships, where technically feasible. Clarkson Research Services (2011) indicates that LNG ships travel at a speed of 19 knots and so these distances can be converted to number of days travel. It is assumed that all ships are 145,000 m^3 (carrying around 65 kt LNG or 90 mcm gas) with hire-rates of \$100 k/d, and have a boil off rate of 0.15 per cent per day (Herrmann *et al.* 2013). It is additionally assumed that each journey requires two days for loading and unloading, which increases costs and gas lost slightly.

As an example, the route from the Middle East (Qatar) to China (Fujian) is 5,625 nautical miles (10,500 km). Including loading and unloading times, this journey takes 14 days in total. Besides the capital investments for the liquefaction and re-gasification plants, this will cost \$15.5/thousand cubic metres (kcm) gas transported. Adding in depreciated capital costs for these plants yields transportation costs of around \$90/kcm. With 2.1 per cent gas lost during transport, and taking account of the compounded losses during liquefaction and re-gasification, in total 13.8 per cent of the gas is also lost.

Since LNG trade is more flexible than pipeline transport, build rate constraints are somewhat less important. Nevertheless, given their capital-intensive nature and long construction time, any liquefaction plants that will be constructed before 2018 will have already been announced. Plants that have been constructed, are in construction, or have been announced are therefore used to set the upper bound on the construction of new facilities up to 2018. The model can, however, choose not to invest in projects that have been announced but not yet constructed if they are not cost effective.

Table 6. Estimated sailing distances between assumed ports within each region for LNG liquefaction and re-gasification in nautical miles.

	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	UK	USA	WEU
AFR				8,362	7,398			4,421	9,285	5,246	5,519	7,574	8,970	2,014	5,397	1,968
AUS				3,053					3,743		8,167	2,305	3,658		12,608	
CAN				5,083				9,448	4,035				4,785			
CHI																
CSA			2,211	9,989				8,463	8,882		3,350	11,138	9,691	4,091	2,247	4,046
EEU																
FSU				1,744		11,751		6,131	960			2,983	1,380		15,203	
IND																
JPN																
MEA			6,771	5,625	8,671			1,299	6,548		9,922	4,429	6,237	6,413	9,796	6,368
MEX																
ODA				1,677					2,562				2,280			
SKO																
UK																
USA				10,301				9,645	9,194				10,003	4,518		4,822
WEU									12,529				12,214	4,469	6,227	

Source: Nautical miles are converted to days travel by dividing by 19 (the assumed average speed of LNG ships) or can be converted to km by multiplying by 1.85. Two additional days are added to each journey to account for loading and unloading.

Scenarios Constructed

3

This section describes the key assumptions within scenarios implemented in this project to investigate the questions posed in Section 1.1.

As discussed in Section 2.1, the base year of TIAM-UCL is 2005. For the scenarios that require some level of GHG emissions reduction, the model is therefore free to take actions to reduce GHG emissions from 2005 onwards. However, despite the Kyoto protocol and other political commitments to reduce emissions, observed global GHG emissions between 2005 and present have not been following the trajectory generally produced in mitigation scenarios. It is thus somewhat unreasonable to allow the model to do this. In contrast, the results from scenarios run that require no GHG abatement actually match observed investment patterns and GHG emissions quite closely.

To prevent mitigation that has not been observed in reality, the results (infrastructure investments, resource extraction etc.) from scenarios that require no GHG emissions reduction between 2005 and 2010 are used in all scenarios regardless of the level of emissions mitigation they require. This increases the difficulty (and hence cost) of meeting emissions reduction and also effectively shifts the base year of the model to 2010.

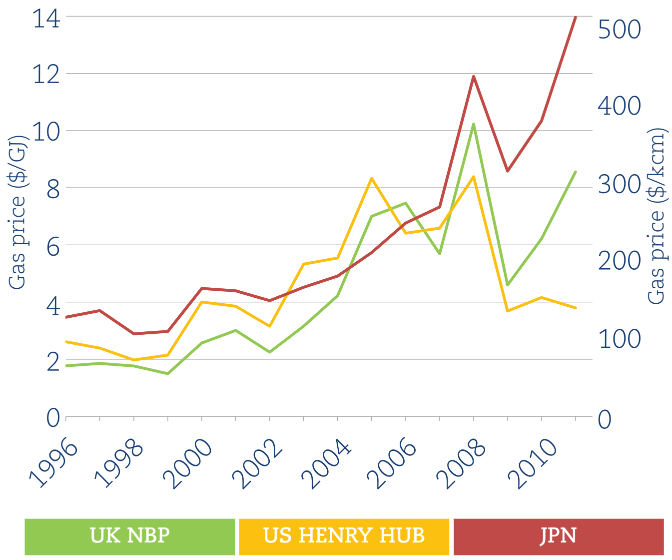
As also noted in Section 2.1, the scenarios that require no GHG emissions reductions are also used to generate 'base prices' for each commodity in each year. These are the marginal commodity costs calculated when meeting the fixed energy services demands in the standard version of the model, which relies upon minimising discounted energy system costs. For the GHG mitigation scenarios, however, the model is run using the elastic-demand version. This allows demands to respond to changes in the prices of meeting the energy service demands that result from the introduction of the new emissions constraints.

A summary of all of the scenarios run in this project along with a brief description of their key assumptions is provided in the Appendix.

3.1 Gas price development

The first set of scenarios aims to help inform the first research question, namely the implications of different future developments of the gas market. Figure 6 presents representative gas prices in the three major gas 'hubs' since 1996 (North America, Europe, and Japan). It can be seen that despite relatively close correlation up to 2008, there has been a large divergence in annual average gas prices since then. This has arisen for a variety of reasons (see Allsopp *et al.* (2012) for details), of which one of the most important is that in some parts of the world the gas price is wholly or partially indexed to the oil price. The different prices, as shown in Figure 6, which result from the different pricing mechanisms in the world, means that there is no 'global' gas price similar to that for crude oil. Whether such a global gas price will develop in the future is uncertain at present, and the implications of this are worth investigating.

Figure 6. Annual average gas prices in the United States, UK and Japan



Source: BP Statistical Review (BP 2013)

Scenarios with two alternative gas market structures are therefore implemented. The first assumes a continuation of the current situation, with a price differential between the three major regional gas hubs, which is independent of the marginal costs of supplying gas to these regions, and is given the suffix *_REGIONALGP*. The second scenario represents a counterfactual to this i.e. with a move towards a 'global gas price' and is given the suffix *_GLOBALGP*.

The GLOBALGP scenarios are easily constructed as they do not require the introduction of any additional constraints or exogenous price changes. As a global supply and demand equilibrium model, the endogenously generated prices rely solely upon marginal costs of production, scarcity rents and transportation costs. No further factors such as gas-to-oil differentials influence prices and so a global gas market is likely to form over time. This is not to say that the gas price will be equal everywhere: the costs of LNG transport (the principal mechanism by which a global gas price could form) are very expensive, and so price differentials will likely remain between regions depending on the dynamics of gas trade.

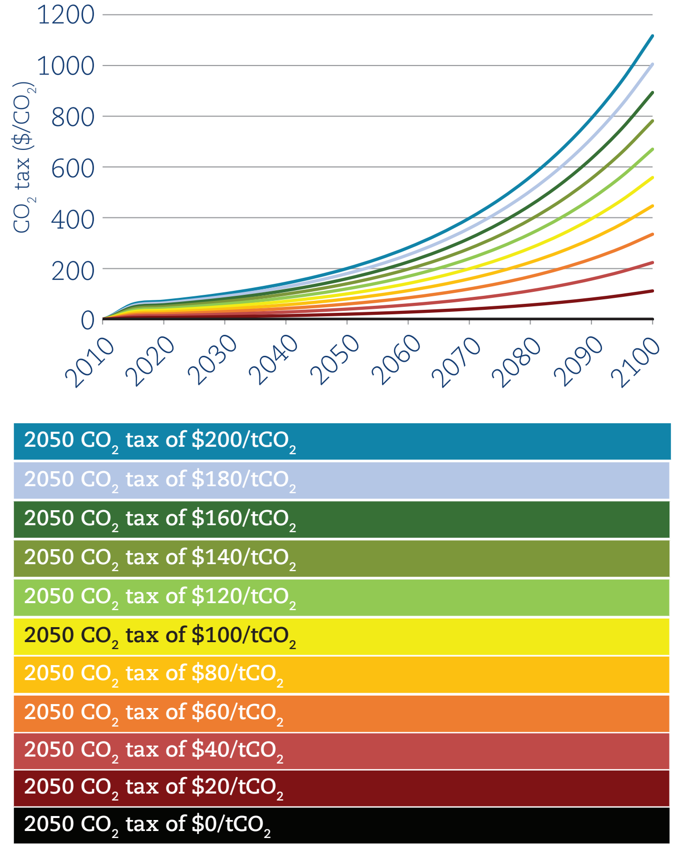
To represent the current situation, in which prices are more divorced from supply-demand dynamics, the REGIONALGP scenario imposes some additional cost mark ups to gas trade between certain regions. An extra cost is added to any gas being traded (by either pipeline or LNG) into any of the Asian basin regions or into any of the European basin regions. This additional cost is added regardless of the source of the gas, so, for example, it will be introduced for a trade even within the Asian basin (e.g. ODA to CHI). To reflect the current differential in prices between regions, this price mark-up is larger for gas flowing into Asian basin regions than European as set out in Table 7.

The cost mark-ups of \$5/GJ (around \$5.3/MMBTU or \$185/kcm) and \$3/GJ (around \$3.2/MMBTU \$110/kcm) have been chosen to reflect the historic average differentials seen between Henry Hub prices and Japan and NBP since around 2008. A more appropriate derivation would require an investigation of past LNG prices and volumes to estimate the differentials that arise over and above the actual marginal costs of supply. This is outside the scope of this research, but the chosen mark-ups will still demonstrate the effects such changes can have, and as mentioned do reflect the historic average differentials. These cost mark ups are not applied to gas produced domestically.

3.2 How gas consumption varies with GHG mitigation

The next area that this report seeks to address is how gas production and consumption varies over time with different GHG mitigation policies. The simplest method by which to examine this is through imposing a large number of differing CO_2 taxes. We therefore introduce a range of CO_2 taxes in 2050 and project these forwards and backwards at the global discount rate (3.5 per cent).

Figure 7. Examples of CO_2 taxes imposed and how these vary over time



The CO_2 taxes that are introduced in 2050 range from \$0/tCO_2 to \$500/tCO_2, with scenarios run in iterations of \$20/tCO_2. A total of 25 runs are therefore implemented. Some examples of these are given in Figure 7. In each of these cases, the CO_2 tax is first imposed in 2015, with the model constrained to a case with no CO_2 taxes up to 2010. As noted in Section 2.1, all prices are given here in 2005 US\$.

Gas price formation based on gas supply-demand fundamentals is a more natural assumption within a global optimisation model such as TIAM-UCL, since, as mentioned above, it does not required the imposition of any additional cost differentials or constraints.

Table 7. Cost differentials added in the REGIONALGP scenarios

No cost mark up for gas traded into regions	\$3/GJ cost mark up for gas traded into regions	\$5/GJ cost mark up for gas traded into regions
AFR	EEU	CHI
AUS	UK	IND
CAN	WEU	JPN
CSA		ODA
FSU		SKO
MEX		
MEA		
USA		

Therefore, unless otherwise noted, these scenarios do not impose the cost markups used in the REGIONALGP scenario and so they carry the assumption that there is a move towards a global gas price.

3.3 Natural gas as a transition fuel

The third and final area of interest regards the role that natural gas can play in a low-carbon energy system. To investigate this, we run discrete scenarios that result in certain levels of average global temperature rise. The definition used here for a 'low-carbon' future is an emissions pathway that is consistent with keeping the global average surface temperature rise below 2°C in all years: the level agreed on by makers that should not exceeded (UNFCCC 2012; UNFCCC 2009). As discussed in the previous section, since the climate module of TIAM-UCL is calibrated to the MAGICC model, there will be around a 60 per cent chance of keeping the temperature rise to this level.

We are also interested in examining scenarios that do not mitigate the temperature rise to this level. This is partly because the IEA (2011) suggests that its 'golden age of gas' scenario, a scenario that modelled a large increase in gas consumption, will lead to a 3.6°C average surface temperature rise, and partly to allow us to investigate changes in gas's role in when the temperature change exceeds the 2°C threshold. We therefore also model emissions pathways that lead to long-term temperature rises of 3°C and 5°C. 'Long term' is taken here to mean the temperature rise in 2200, and we constrain the model to ensure that these temperature targets are not exceeded in any time period i.e. no 'overshoot' of temperature is permitted within the modelling period.

There are a wide variety of emissions pathways consistent with these temperature rises. The focus here is not specifically on emissions trajectories, however, and so we have chosen discrete scenarios with the assumptions set out in Table 8. For the emissions-mitigation scenarios (those that limit

Table 8. Description of assumptions for the discrete emissions reduction scenarios

Scenario Name	Description
REF	The model is constrained to keep the average global surface temperature rise to less than 5oC in all years to 2200. No other emissions constraints are imposed. Since allowed emissions under this scenario are so high (i.e. the constraint is very lax), up to 2050 this scenario is almost identical to the scenario with a $0/t$CO_2$ tax from Section 3.2. The temperature rise in 2100 is close to 4°C.
3DS	From 2005 to 2010, the model is fixed to the solution given in REF, i.e. we assume that no emissions reductions are required. From 2010-2015, it is assumed that the model must be on track to achieve the emissions reduction pledges set out in the Copenhagen Accord (UNFCCC 2009), but no other emissions reductions are required. From 2015 onwards the model must meet the Copenhagen Accord emissions reductions in 2020, and emissions must be such as to keep the average global surface temperature rise below 3°C in all years to 2200.
2DS	The constraints between 2005 and 2015 in this scenario are identical to the 3DS. From 2015 onwards the model must meet the Copenhagen Accord emissions reductions in 2020, and emissions must be such as to keep the average global surface temperature rise below 2°C in all years to 2200.

the temperature rise to 3°C and 2°C), we assume that there are only relatively modest efforts to limit emissions in early periods as explained. As with the scenarios in the previous section, these scenarios assume a move towards a global gas price unless specified otherwise.

A key assumption in TIAM-UCL is the availability of carbon capture and storage (CCS). It has been suggested, and is plausible, that the deployment of CCS will permit wider exploitation of fossil fuel resource base (IEA 2013b), and so it is likely to have a major impact on the levels of gas produced and consumed. Nevertheless, whether CCS will actually be commercialised or not is currently far from certain (Watson *et al.* 2012). For the 2DS scenario, we therefore run two separate scenarios, one which permits the widespread deployment of CCS, and the other which assumes that CCS is not available in any time period. The suffix _noCCS is added when it is assumed that CCS is not available.

In scenarios that permit CCS, it can first be applied to electricity and industrial technologies from 2025. Assumptions are purposely optimistic on the rate at which it can be deployed: in 2025 in each region CCS can be applied to a maximum of 15 per cent of total electricity generation while in the industrial sector it can capture between 10-20 per cent of process emissions and emissions from generating process heat (depending on the technology and specific sector). After 2025 all CCS technologies can grow at a maximum rate of between 10-15 per cent per annum. Some maximum levels of CCS penetration are, however, applied in certain sectors. For example, a maximum of 54 per cent of emissions can be captured from process heat technologies in the iron and steel industries in each region. CCS is assumed to have a 90 per cent capture rate.

3.3.1 Characterising natural gas as a transition fuel

Before looking at results, it is worth exploring here what is actually meant by the phrase a gas 'bridge' or natural gas 'acting as a transition fuel' as introduced in Section 1 because at present there is no clear or generally accepted definition. For example, Stephenson *et al.* (2012) criticised the 'greenwashing' of natural gas as a 'bridging fuel', yet the authors did not actually explicitly state what they meant by this (other than noting that natural gas had been characterised as a 'transition fuel for a low carbon energy system'). Similarly, a report by the IEA (2011) was interpreted by some analysts as heralding a 'golden age of gas' with gas acting as a 'bridge towards renewables'

(Aguilera & Aguilera 2012). However, as mentioned above, the IEA explicitly stated that this 'golden age of gas' scenario would lead to a 3.6°C average surface temperature rise, and that it had not attempted to examine the role of natural gas in a scenario leading to a 2°C rise.

MIT discussed gas's role in the United States and concluded that 'natural gas provides a cost-effective bridge to … a low-carbon future' (Moniz *et al.* 2010). This conclusion was based on modelling results indicating an absolute rise in total gas consumption from 2010 out to 2040 (before dropping slightly in 2050) in a scenario that resulted in US CO_2 emissions falling by 50 per cent by 2050 from their levels in 2005.[5] The IPCC WGIII (2014) also recently stated that: 'natural gas power generation without CCS acts as a bridge technology'. This was based on the deployment of this technology rising in an absolute sense from current levels before peaking and subsequently declining to below current levels by 2050.

Levi (2013) uses an alternative definition, based on the relative differences in consumption between an emissions mitigation scenario (where 'mitigation' here means a reduction in emissions below some unconstrained level) and a non-mitigation scenario. The author defined the bridge to be the time when global consumption of natural gas, in a scenario without carbon capture and storage that stabilised CO_2 concentrations at 450 ppm (the approximate concentration commensurate with a 2°C temperature rise), rose 'substantially' above consumption in a 'business-as-usual' scenario.

There are evidently here two alternative interpretations of what is meant by gas acting as a bridging or transition fuel in a scenario of emissions mitigation that leads to a low-carbon energy system. The first is an absolute increase in consumption from current levels followed by a peak and subsequent decline.

[5] It is worth noting that a 50 per cent reduction in CO_2 emissions in the United States from 2005 to 2050 is likely an insufficient reduction if the world is to have a reasonable chance of limiting the global temperature rise to 2°C. IIASA (2012), for example, suggests that US GHG emissions must fall by at least 70 per cent in over the same time frame.

The second is a relative increase in consumption, over some period, in a GHG mitigation scenario compared with consumption in a non-mitigation scenario. There is also disagreement over the level of emissions reduction in the GHG mitigation scenario that should be specified for this to qualify as a 'low-carbon scenario'.

However, since the 2°C limit was explicitly included in the Copenhagen Accord of 2009 (UNFCCC 2009) and is still included in the text adopted by the UNFCCC in Durban (UNFCCC 2012), we use a scenario with emissions commensurate with a 2°C temperature rise as our principal GHG mitigation scenario.

In this report we will therefore make reference to gas acting as a transition or bridging fuel in scenarios that satisfy this 2°C temperature rise limit in both a relative and absolute sense. It is worth clarifying precisely what is meant by these roles, and the scenarios with which these roles are being compared, since this is something that otherwise can lead to some confusion (Strachan 2011).

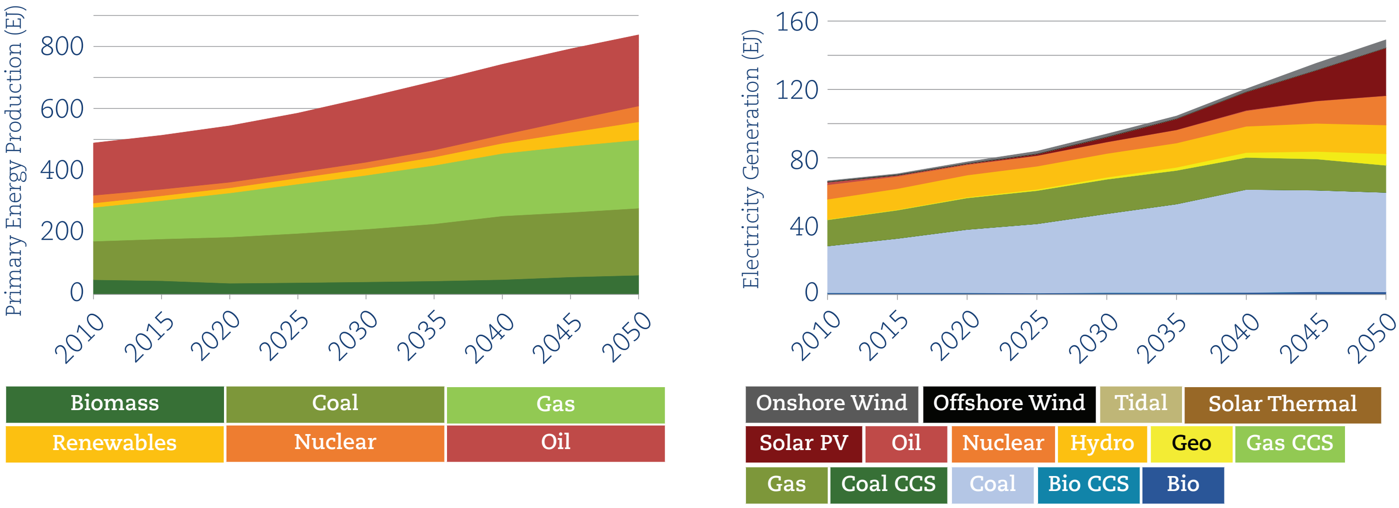
Natural gas acts a 'relative' bridge in a region (or globally) when total consumption is greater in some period in a scenario leading to a 2°C average temperature rise than in a scenario that contains no GHG emissions reduction policies.

Natural gas acts as an 'absolute' bridge in a region (or globally) when total consumption rises above current levels over some period until it reaches a peak and subsequently enters a permanent or terminal decline.

Gas Price Development

4

Figure 8. Primary energy production (left) and electricity production (right) in REF_GLOBALGP



Note: Electricity from nuclear has been multiplied by 3 in primary energy production, following IEA (2012)

4.1 REF_GLOBALGP [6]

The first scenario presented here is REF_GLOBALGP. As discussed above, this is designed to result in a long-term temperature rise of 5°C (in 2200) and a global gas price market. It is important to highlight again that this is not a continuation of the existing situation in gas markets, which are characterised by very different prices in different regions globally with these prices often based on oil indexation.

However, as discussed above the formation of a global gas price, with price formation based on gas supply-demand fundamentals, is a more natural assumption within a global optimisation model such as TIAM-UCL. REF_GLOBALGP therefore helps to provide context to the subsequent gas production and consumption projections. It is thus also useful to explore some of the wider dynamics of the energy system in this scenario. The differences between this scenario and one which continues the existing situation in gas markets is discussed below in Section 4.2.

Figure 8 displays global primary energy consumption and the global electricity supply in REF_GLOBALGP. Primary energy consumption increases steadily over the model horizon such that it has risen by 30 per cent from 2010 levels by 2030 and 70 per cent by 2050. Most sources of energy increase over the model horizon, but fossil fuels clearly grow by the largest absolute amount: coal and gas consumption both grow by over 100 EJ/annum, with coal rising by 75 per cent from 2010 levels and gas more than doubling.

The rise in oil consumption is slightly more moderate (35 per cent by 2050), but it still remains the single largest energy source consumption. There is some uptake of renewable sources, particularly solar after 2030, but this growth is much more modest than for the fossil fuels.

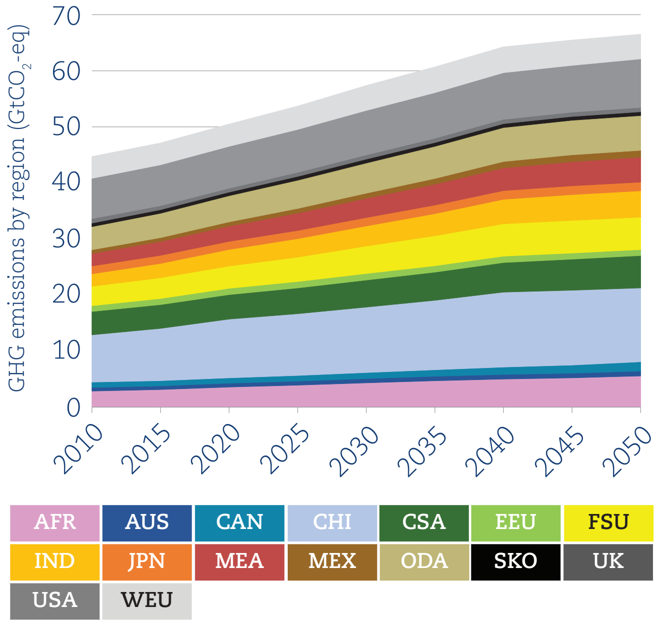
Despite a slight flattening in the 2040's, it is evident that coal continues its dominance of the electricity sector globally. From 2020 to 2040, coal accounts for close to 50 per cent total electricity generation, while gas accounts for an average of around 20 per cent total generation over the same period. Since it is assumed in this scenario that CO_2 emissions are not important, a number of regions (particularly Europe) that are currently tending to move away from coal-based electricity generation reverse this trend and construct a large number of new coal power plants. It is also important to recognise that concerns over local pollution and air quality are ignored in this scenario, which may in reality curtail the growth in coal consumption to some extent. Total installed capacity of coal generation thus grows by 50 per cent from 2010 levels by 2030. These results have important implications when discussing the differences between the low-carbon scenarios in subsequent sections. Hydroelectricity remains that largest renewable source of electricity until 2040 when it is overtaken by solar PV, which grows to 20 per cent of total generation in 2050. Finally, following a slight reduction from current levels until 2035, nuclear eventually grows to around 10 per cent of total generation in 2050, with a global installed capacity of 630 GW.

[6] The assumptions contained within the scenarios presented in this section are tabulated in the Appendix.

Figure 9 displays the consequent growth in GHG emissions globally. From around 45 Gt CO_2-eq in 2010, GHG emissions rise at an average of 1 per cent/year to over 65 Gt CO_2-eq in 2050. China accounts for over 20 per cent of this rise, but annual emissions in India, Africa and the Middle East all grow by around 2.5 Gt CO_2-eq. Nevertheless, per capita emissions remain far higher in developed regions, with levels in Canada (given the extent of unconventional oil production) by far the highest (30 tCO_2/capita in 2050).

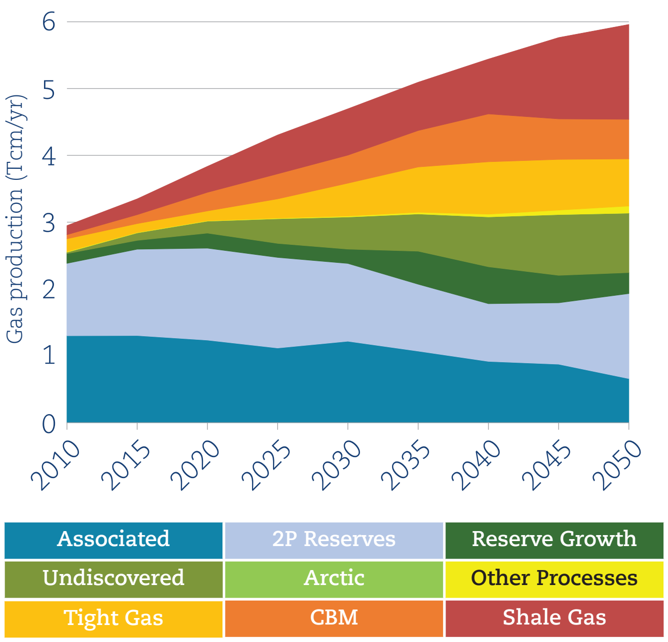
Figure 10 shows gas production by type and region. Total gas production doubles by 2050, with the unconventional sources of gas (shale gas, tight gas and coal bed methane) accounting for most of this growth. Of these, shale gas rises to the largest degree, and annual production exceeds 1 trillion cubic metres (Tcm) from 2040 onwards. Similar to the present situation, there remains a diverse mix in production geographically and no single region accounts for more than 25 per cent global production in any period. China has the largest growth in relative terms (more than tripling by 2050), but the Middle East grows most in absolute terms (by over 0.8 Tcm annually). Production by 2050 falls from current levels in only two regions: in the USA and in the UK.

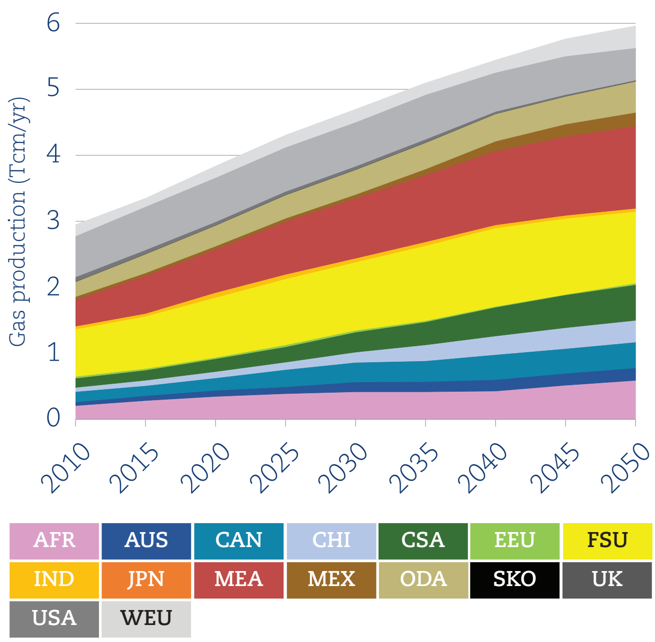
Figure 9. Breakdown of regional GHG emissions in REF_GLOBALGP



Production falls in the USA mainly because of a large drop in shale gas production. This is shown in Figure 11, which presents the regional breakdown of shale gas production globally. Shale gas in the USA continues to grow out to 2030 (peaking at just over 425 Bcm/year) but after this, production falls quite rapidly, to almost negligible levels by 2040.

Figure 10. Gas production by category and region in REF_GLOBALGP





[7] The sweet spot within each shale play is that which has been identified by drilling as having the most productive (in terms of rates and costs of production) qualities – see e.g. McGlade et al. (2013a)

We showed previously in Figure 4 how we model the availability and production costs of shale gas in each region. By 2040 the USA has exhausted all of the cheapest cost resource available. This can be interpreted as having effectively produced all of the resource within each shale play's 'sweet spots'[7]. Therefore, while a significant proportion of resource remains in each shale play, the production costs (shown in Figure 11) are too high so that it is more cost effective to import gas from Canada and pursue other sources of domestic production. In 2050, the economics of non-sweet spot production are more favourable and so it can be seen in Figure 11 that there is the beginning of a re-emergence of US shale gas production.

In the UK, while there is some level of shale gas and coal-bed methane production (discussed in detail in Section 6.3), but this is insufficient to offset the decline in its conventional production and so overall production declines.

The other major sources of shale gas production are Central and South America (CSA), which exceeds 300 Bcm by 2050, and Canada, which, as mentioned, exports a large part of its over 200 Bcm production to the United States in later periods. In contrast, with high cost relative to other energy sources (particularly domestic and imported coal and imported natural gas), there is no production of shale gas in China. Nevertheless, it can be see that generally there is quite a wide geographical distribution of shale gas resource exploitation.

Figure 12 indicates the sectors in which this gas is consumed globally. There is growth in all sectors other than electricity, which falls slightly over the model horizon (although electricity production from gas initially grows as there is uptake of numerous efficiency improvements in gas generation). The industry sector maintains a total share of just under 40 per cent and so continues to dominate consumption. There is, however, a much larger level of growth in gas as a transport fuel. Gas is used both as a marine fuel (using liquefied natural gas), and for road transportation, principally medium- goods vehicles (using compressed natural gas).

Figure 13 provides details of inter-regional gas trade. Despite some slight growth in LNG in near-term periods, generally traded volumes remain around current levels. Consequently, as shown in Figure 14, LNG's share of total gas transported between regions falls until around 2030 from its current level of just under 50 per cent to below 30 per cent. In later periods, Australia takes a larger and larger share of the LNG market as other regions move towards pipeline transport. There is also a major shift in traded volumes from the Other Developing Asia (ODA) region. Despite growing its domestic production, the growth in domestic consumption means that from an initial export level of 65 Bcm/year in 2010, exports fall steadily so that it becomes a net LNG importer by 2035 and is importing nearly 100 Bcm/year by 2050.

Figure 11. Shale gas production separated by region in REF_GLOBALGP

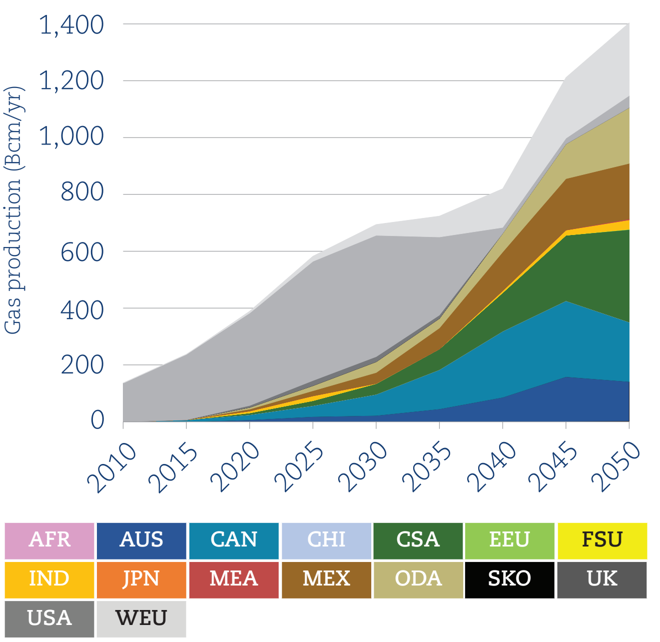


Figure 12. Gas consumption by sector in REF_GLOBALGP

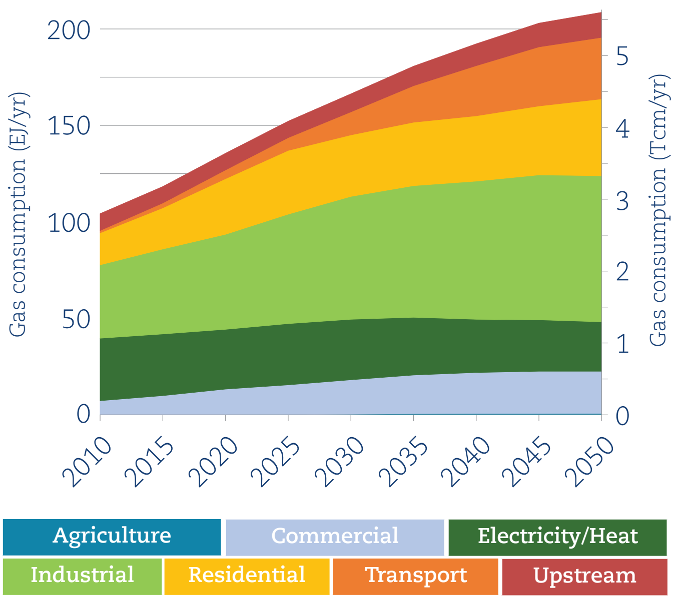


Figure 13. Gas traded by pipeline (left) & LNG (right) in REF_GLOBALGP - positive figures represent exports and negative figures imports

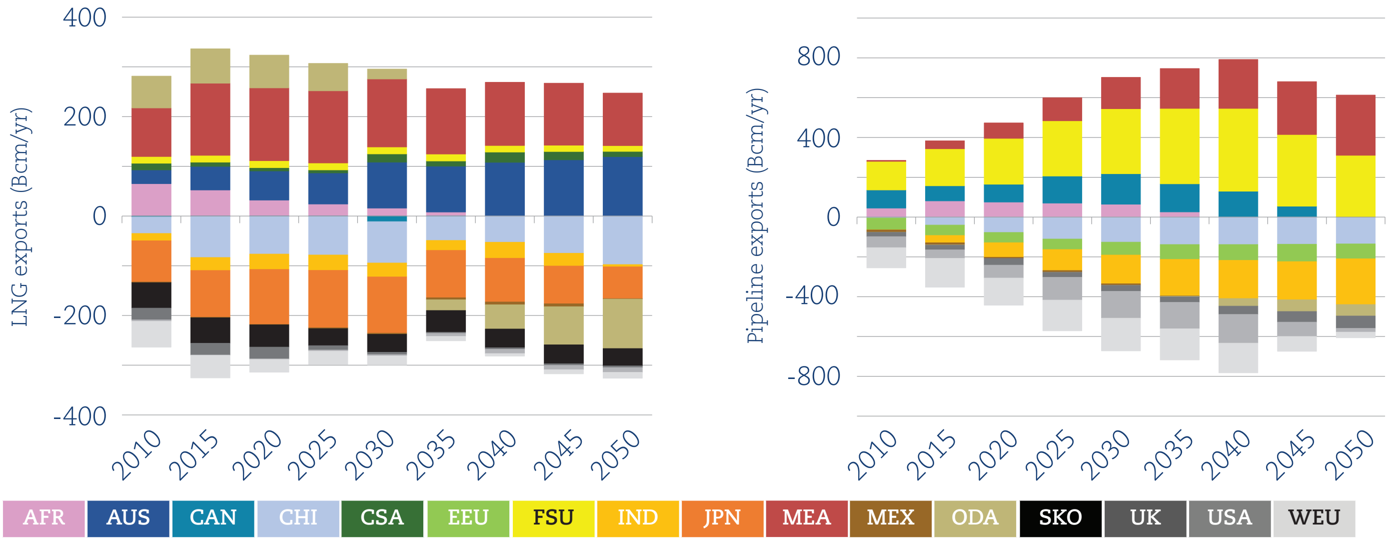
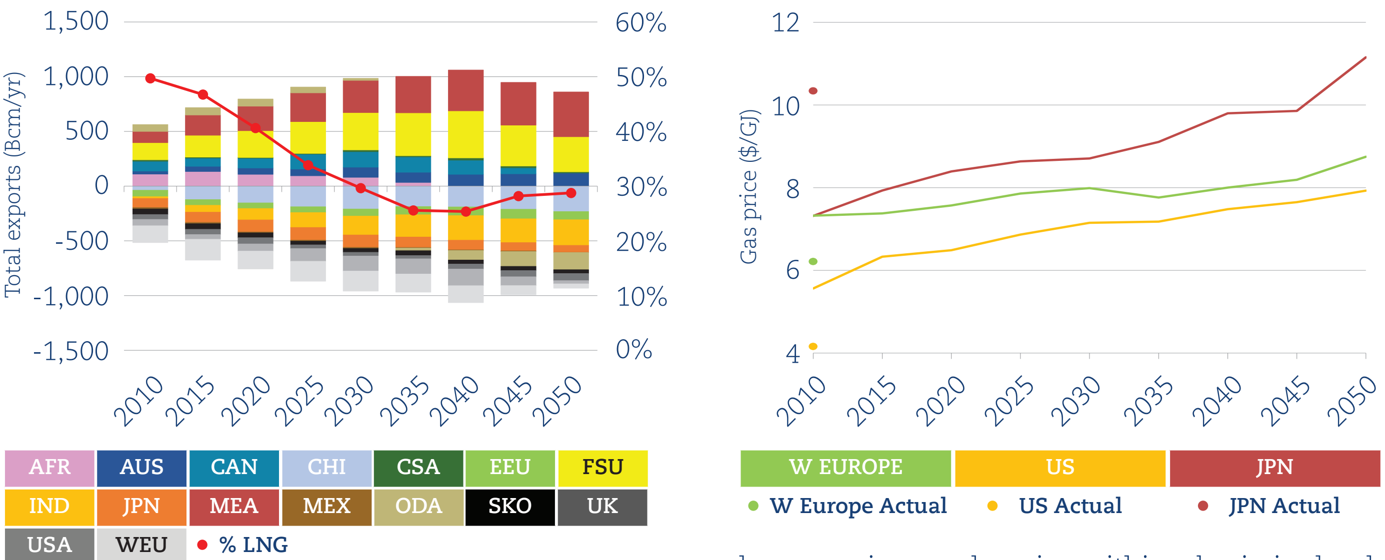


Figure 14. Net gas traded (left) & regional gas prices from trading hubs (right) in REF_GLOBALGP

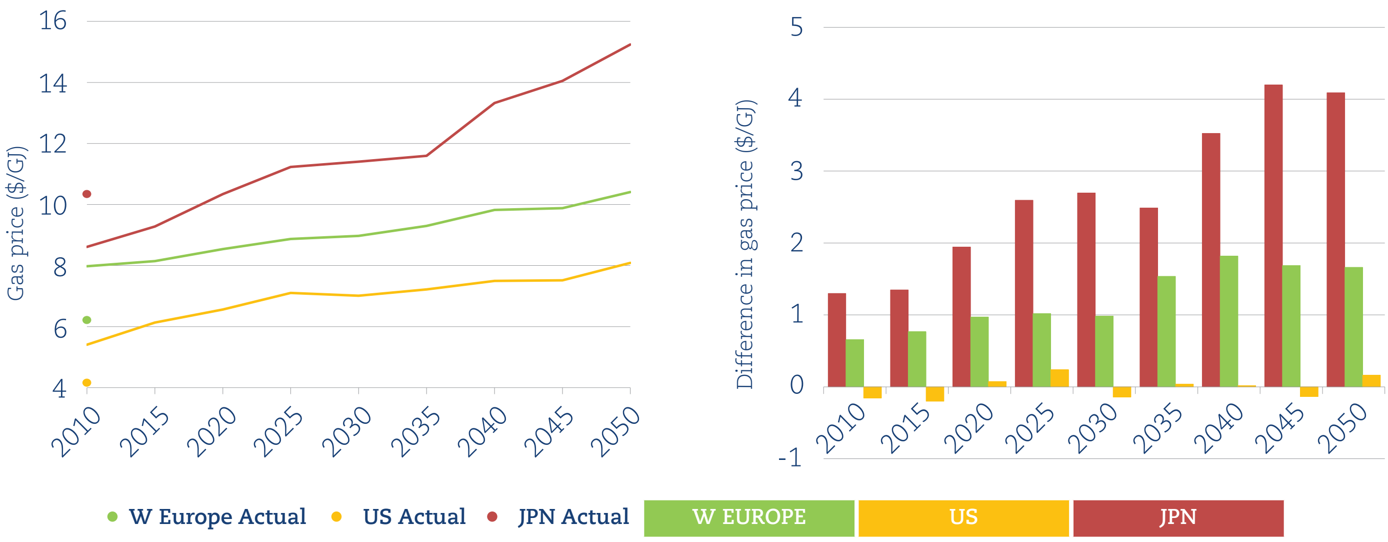


There is also a reduction in LNG exports from African countries, with all of their exports to Europe displaced by pipeline trade (both from Africa and FSU). Overall, the FSU continues to dominate pipeline trade, which grows exports to Europe, but more significantly also increases its exports to China (to 140 Bcm/year by 2050). Exports by pipeline also rise from the Middle East, principally to India but also in later periods to ODA.

The right-hand side of Figure 14 shows internally-generated gas prices from representative regions in each of the three main basins identified in Section 3.1, with the price differences from the single global gas price in the model reflecting the difference in transport costs from producer to consumer regions. Other regions in each of the basins display slightly different price dynamics, however since each region within a basin is closely linked by a number of trade processes, differences are more marginal than those between basins.

It can be seen that the price differentials in TIAM-UCL are not nearly as wide as the differentials seen currently. There are numerous factors that influence actual market prices that are not (and cannot be) included within TIAM-UCL. For example, the LNG industry is prone to major supply-demand cycles, such as the shortage of LNG ships that led to a more-than doubling of the price of chartering an LNG ship in 2011, which can have a significant effect on prices in a given year. Nevertheless, the prices in TIAM-UCL do maintain the current pattern of lowest prices in the United States followed by Europe and with prices highest in Japan. They also exhibit a steady increase over the model horizon.

Figure 15. Gas prices in REF_REGIONALGP and differences in gas price from REF_GLOBALGP



4.2 Effects of a globalised gas price

This section primarily discusses the differences between the scenario that assumes a continuation of the current situation in gas markets (REF_REGIONALGP) and the scenario described above that assumes a move towards a global gas price. Figure 15 first presents the gas prices in REF_REGIONALGP in the three different regional basins. There is a continuation of large cost differentials between the regions, and the price in Japan grows to over $15/GJ – a near doubling over the model horizon. Again these prices generated do not match the actual prices in 2010, nevertheless, as above, the ordering of prices generated in TIAM-UCL is correct in 2010, with the United States cheapest and Japan most expensive. The relative cost differential between the USA and Europe is also approximately correct. It is also noticeable that the regional differences in price between REF_REGIONALGP and REF_GLOBALGP are not as large as the imposed cost mark-ups that were shown in Table 3.1 ($3/GJ to Europe and $5/GJ to Japan).

This occurs both because there is a higher level of gas consumption in all regions in the European and Asian basins when there is a move towards a (lower) global gas price in REF_GLOBALGP, and because they also produce less gas domestically. This is shown in Figure 16 with positive figures meaning that consumption or production is greater in REF_GLOBALGP. For example in the 2020s, production in China is around 100 Bcm lower and it consumes around 80 Bcm more gas in REF_GLOBALGP than in REF_REGIONALGP. Similarly, throughout the 2030's production in Europe is around 100 Bcm lower in REF_GLOBALGP while consumption is over 50 Bcm greater.

Conversely, the exporting regions produce considerably more gas in REF_GLOBALGP and noticeably reduce domestic consumption. For example, production by the Former Soviet Union (FSU) region in the 2030's is around 250 Bcm greater in REF_GLOBALGP, while consumption is an average of 150 Bcm, or around 15 per cent, lower. It is worth noting, however, that consumption in FSU in both scenarios grows in absolute terms from current levels (by 35 per cent in REF_GLOBALGP and over 70 per cent in REF_REGIONALGP in 2050); in reality this may be mitigated by the considerable efficiency savings that are thought to be available, but the model does not take these into account.

Despite these changes at the regional level, there is not a major difference on aggregate global production or consumption levels. The net change shown in Figure 16 remains less than 250 Bcm globally in all periods, less than 4 per cent total consumption in REF_GLOBALGP. As a result, the main change between a move towards a global gas price and a continuation of regional gas pricing scenario is the level of gas that is traded. This is demonstrated in Figure 17, which displays the percentage of domestic production that is exported (by both by pipeline and LNG) from the three major exporter regions (Australia, the Former Soviet Union, and the Middle East).

In REF_REGIONALGP, the level of exports from all three regions falls dramatically. Exports from FSU in particular fall to negligible levels by 2040, but exports from MEA and AUS also fall from current levels to 10 per cent and 25 per cent respectively. These changes reflect the higher prices, and therefore the reduced consumption and increased production in the importing regions.

Figure 16. Differences in gas production (left) and consumption (right) between REF_GLOBALGP and REF_REGIONALGP BALGP

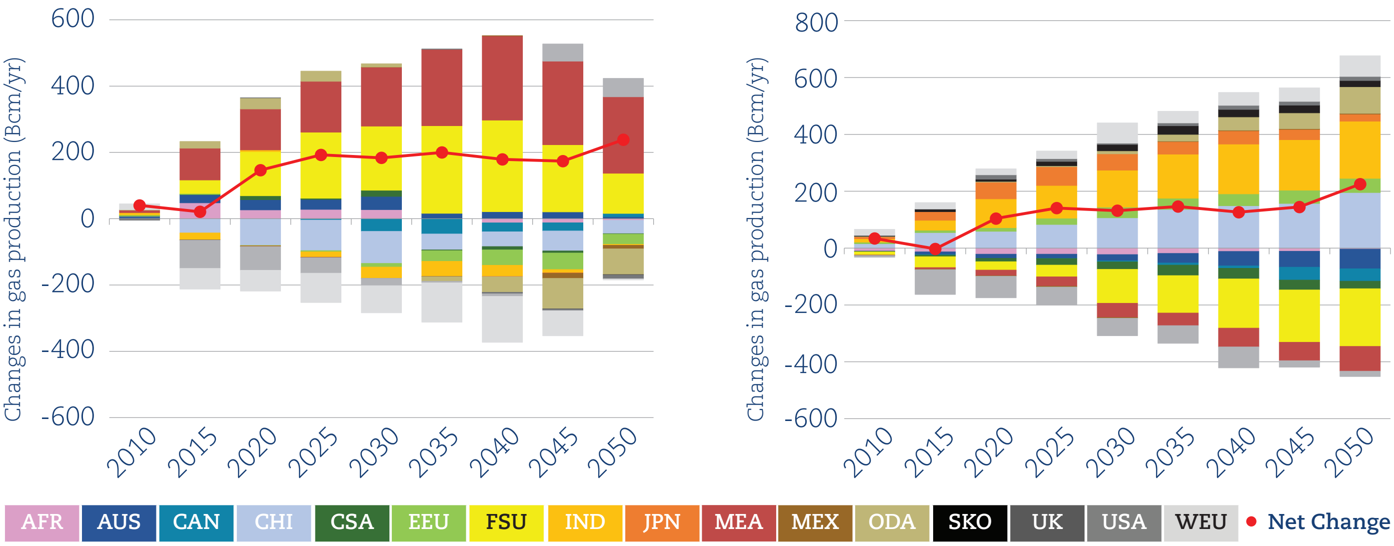
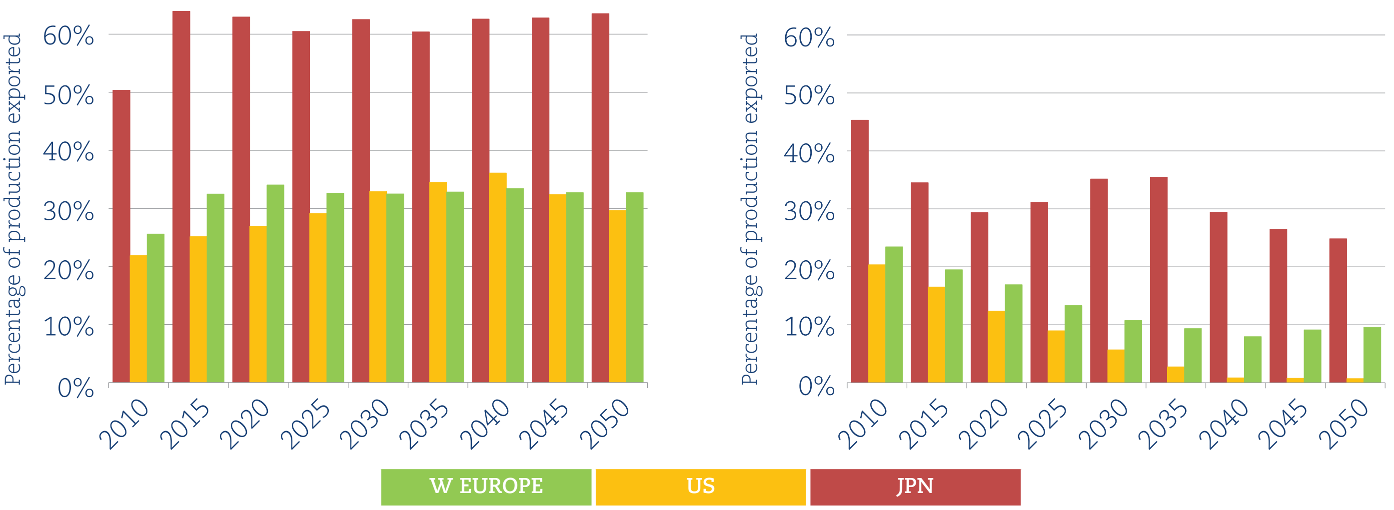


Figure 17. The percentage of domestic gas production exported by Australia, the Former Soviet Union and Middle East in REF_REGIONALGP (left) and REF_GLOBALGP (right)



In stark contrast, in REF_GLOBALGP Australia consistently exports around 60 per cent of its production to other regions over the model horizon, up from around 50 per cent currently), while FSU and MEA export between around 30-35 per cent (although the absolute level of exports is of course higher in these two regions).

These results therefore suggest that a move towards a global gas price based on supply-demand dynamics, and a move away from oil price indexation, is the strategy that gas-exporting regions should follow if they want to increase, or even maintain, their current levels of exports. Further dynamics in changes to volumes of gas traded, looking at the relative importance of market structure and GHG mitigation, and distinguishing between LNG and pipeline trade, are discussed in more detail in Section 5.3.

4.3 Summary of results

This section aimed to explore many of the gas market dynamics in TIAM-UCL in a scenario that disregards any need to cut GHG emissions. There is large uptake in the production and consumption of all fossil fuels, with coal in particular dominating the electricity system. It is unconventional sources of gas production that account for much of the rise in natural gas production; with shale gas exceeding 1 Tcm after 2040. There is a wide geographical distribution of shale gas production, although production from the United States peaks in 2030 at just over 425 Bcm/year before subsequently declining. Gas consumption grows in all sectors apart from the electricity sector, and was found to be cost effective for both marine transport (as LNG) and in medium-goods vehicles (as compressed natural gas (CNG)).

We also modelled two different scenarios for future gas markets. One continued current regionalised gas markets, which are characterised by very different prices in different regions with these prices often based on oil indexation, while the other allowed a global gas price to form based on gas supply-demand fundamentals. We found only a small change in overall global gas production levels between these but a major difference in levels of gas trade. We concluded that if gas exporters choose to defend oil indexation in the short-term, they may end up destroying export markets in longer term: a move towards pricing gas internationally, based on supply-demand dynamics, was thus shown to be critical if they are to maintain their current levels of exports.

The Variation of Gas Consumption with GHG Mitigation

5

We saw in the previous section that gas production doubles by 2050 when there is no constraint on GHG emissions. There was also a major increase in the level of coal production. It is therefore possible that, when a GHG emission constraint is applied, providing an incentive to move away from carbon-intensive coal in the electricity and other sectors, there may be an even greater uptake of gas. On the other hand, given that GHG emissions also inevitably result from the consumption of gas, a strong move towards mitigating GHG emissions could force gas out of the system. This section investigates the effect on gas consumption of different emission mitigation policies, focusing on those policies that lead to the largest uptake of gas in the future[8]. As discussed in Section 3.2, one of the simplest ways of exploring these dynamics is by introducing a wide range of CO_2 taxes and examining how this affects consumption levels.

5.1 Global level

To investigate the changes in gas consumption globally under different imposed CO_2 taxes, it is useful to understand the more general changes that occur in both the energy and electricity systems as the tax increases. This can be seen in Figure 18, which includes the results from all of the CO_2 taxes ranging between $0/t$CO_2$ to $500/t$CO_2$ in 2050 (and rising at 3.5 per cent before and after). All of these scenarios permit the use of carbon capture and storage (CCS), and as mentioned in Section 2.1 all prices are in 2005 US$.

For each figure, we take the consumption levels from all primary energy sources in a single given year for the first CO_2 tax run ($0/t$CO_2$) and plot these along the y-axis. We then move along the x-axis to the next run (the 2050 $20/t$CO_2$ run) and again plot primary energy consumption of each source. This is then repeated for all other runs. An identical process is carried out for the electricity sector. Figure 18 thus gives total primary energy consumption and total electricity generation globally in 2020, 2030 and 2050 at the different CO_2 tax levels that exist in each of these years. Since the CO_2 taxes in each run rise at the global discount rate of 3.5 per cent, a 2050 tax can be translated into its equivalent value in 2020 and 2030 - these are the taxes given on the y-axis. For example, a $300/t$CO_2$ in 2050 is equivalent to a tax of $105/t$CO_2$ in 2020 and $150/t$CO_2$ in 2030.

As will be discussed in more detail in the next section, when CCS is available, the CO_2 taxes generated endogenously by TIAM-UCL under the 2°C and 3°C scenarios that were described in Table 8 rise to $200/t$CO_2$ and $15/t$CO_2$ in 2050; these are shown as dotted lines in Figure 18 for reference.

In 2020, gas consumption increases steadily as the CO_2 tax is increased. In general this occurs at the expense of coal, which steadily loses its share of total energy consumption at higher and higher taxes. At its minimum, which occurs when there is no CO_2 tax, gas comprises 27 per cent primary energy consumption with coal also accounting for 27 per cent. At the CO_2 tax commensurate with the 2°C scenario ($70/t$CO_2$ in 2020) gas's share has risen to 33 per cent and coal's fallen to 15 per cent, while at a tax of $170/t$CO_2$ in 2020 gas rises to 37 per cent and coal falls to its minimum of 7 per cent. A similar pattern of gas replacing coal at higher CO_2 taxes is seen in the electricity sector, since gas offers one of the few short-term methods of decarbonising the electricity system.

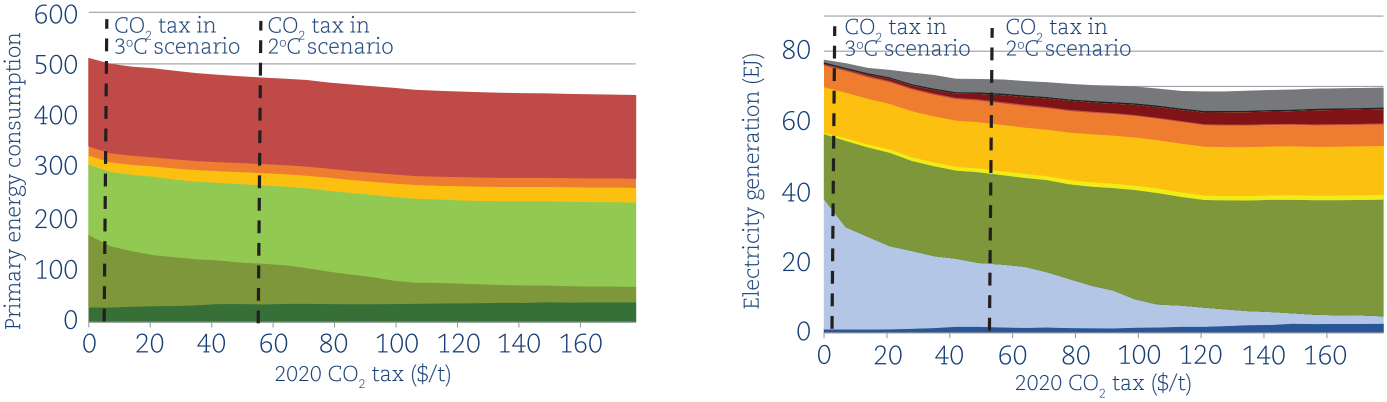
For primary energy consumption in 2030 and 2050, there is a much more rapid reduction in the use of coal at relatively lower CO_2 taxes. For example, in 2020 coal consumption falls to 50 per cent of the level in the $0/t$CO_2$ run when the CO_2 tax in 2020 is $70/t$CO_2$. This is equivalent to a CO_2 tax in 2050 of $200/t$CO_2$. In contrast in 2050, the CO_2 tax must only be $20/t$CO_2$ for coal consumption to have fallen to 50 per cent of the level in the $0/t$CO_2$ run. This is an important result as it can be seen that even though only a modest CO_2 tax is required in the 3°C scenario (discussed in more detail below) in later periods this corresponds to a major drop in coal consumption.

In 2030 and 2050, gas use does again increase to offset some of the reduction in coal use as the CO_2 tax increases, but there is a larger contribution from energy demand reduction, and an increase in the use of biomass. At CO_2 taxes in 2030 above $70/t$CO_2$, gas's contribution to total primary energy consumption begins to shrink as nuclear and renewables play an increasing large role.

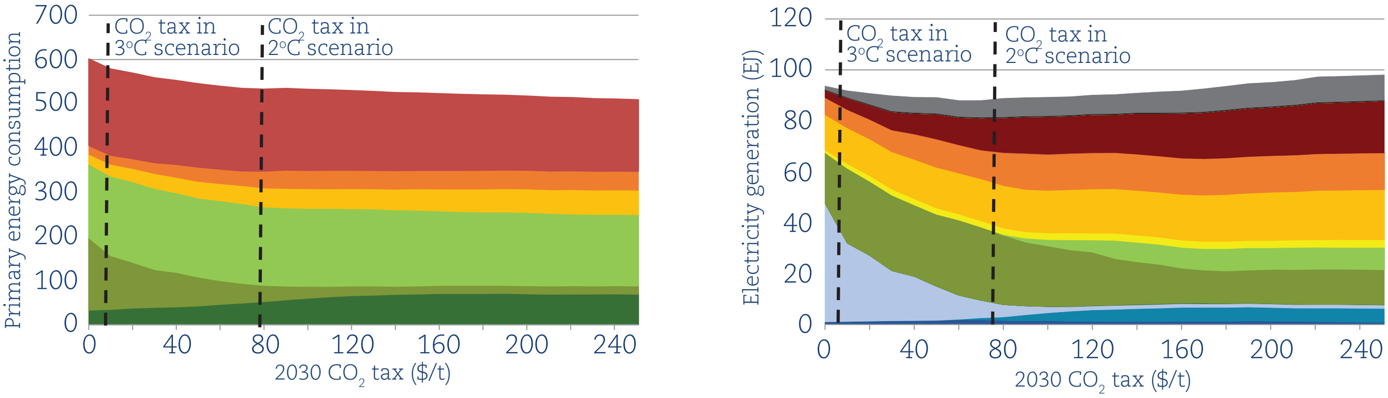
[8] The assumptions contained within the scenarios presented in this section are tabulated in the Appendix.

Figure 18. Changes to primary energy consumption (left) and total electricity production (right) in 2020, 2030 and 2050 under scenarios with CO_2 taxes that rise to between \$0/tCO_2 and \$500/tCO_2 in 2050

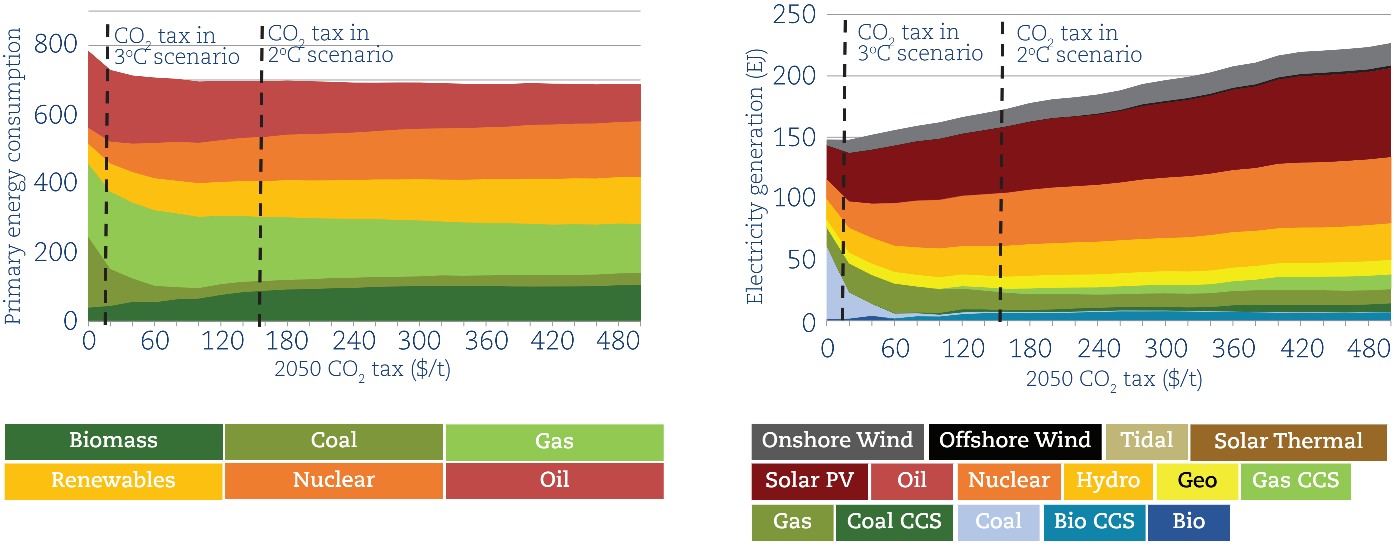
2020



2030



2050



In 2030 gas continues to be used to produce a significant quantity of electricity, the majority of which, even at high CO_2 taxes, is unabated. There are large quantities of electricity produced from solar PV, and unabated gas is one of the few technologies within TIAM-UCL that can be used as back-up generation. Some gas plants are nevertheless also run as base load. Above a 2030 CO_2 tax of \$80/tCO_2, electricity from gas with CCS starts to increase, but it never exceeds more than 40 per cent total electricity generation from gas at any imposed CO_2 tax.

Gas plays a much more muted role in the 2050 electricity system. The percentage of total generation coming from gas is highest when there is a low imposed CO_2 tax of \$20/tCO_2 (when it accounts for 16 per cent of total generation). At the CO_2 tax commensurate with the 2°C scenario, this has fallen to 10 per cent, the majority of which is still unabated generation providing flexible support to the intermittent renewables (which themselves contribute 40 per cent of total generation).

Figure 19 looks more closely at global gas consumption in isolation under a selection of the runs with different imposed CO_2 taxes. It is evident that a higher CO_2 tax leads to increased consumption in near-term periods (up to around 2030), but lower consumption over the longer-term. The key reason for the increase up to 2030 is that at progressively higher CO_2 taxes, coal becomes less and less cost-effective. As demonstrated by the top panels in Figure 18, gas offers one of the few short-term options for replacing this coal since it is not possible to use any CCS technologies or deploy renewable or other low-carbon technologies on as large a scale as needed to offset the drop in coal.

Figure 19 demonstrates that an important step in understanding the question of what scenarios lead to the greatest gas consumption in the future, is addressing what is meant by 'the future'. In other words, over what timeframe in the different scenarios does gas consumption reach its highest levels, and how high are those levels? Figure 20 therefore rearranges the data from all of the CO_2 tax runs and presents global gas consumption (y axis) at different CO_2 taxes (x axis) for milestone years. The lowest line, for example, is global gas consumption in 2020 at different CO_2 tax levels. In this year, as the CO_2 tax increases, total gas consumption increases. This demonstrates that in the short-term (i.e. out to 2020), the more stringent the CO_2 tax, or equivalent, the higher the level of gas consumption.

Figure 19. Global gas consumption over time under different CO_2 tax scenarios

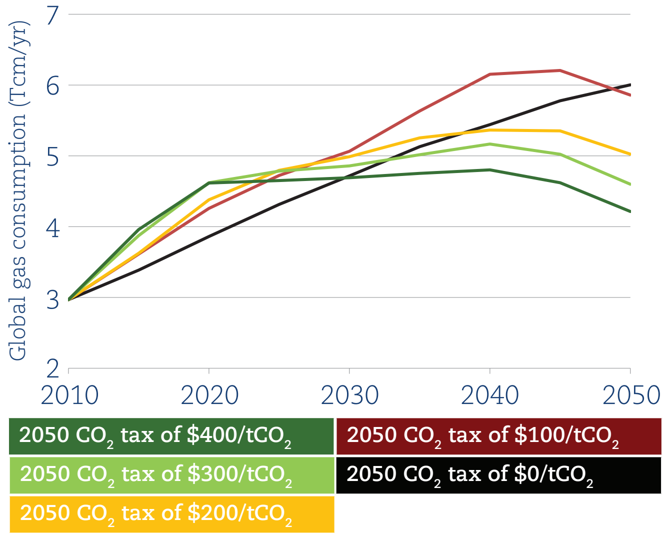


Figure 20. Global gas consumption at different CO_2 tax levels for different years

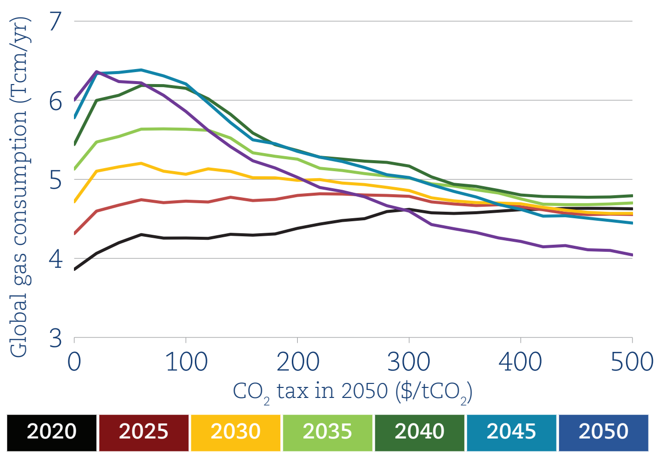
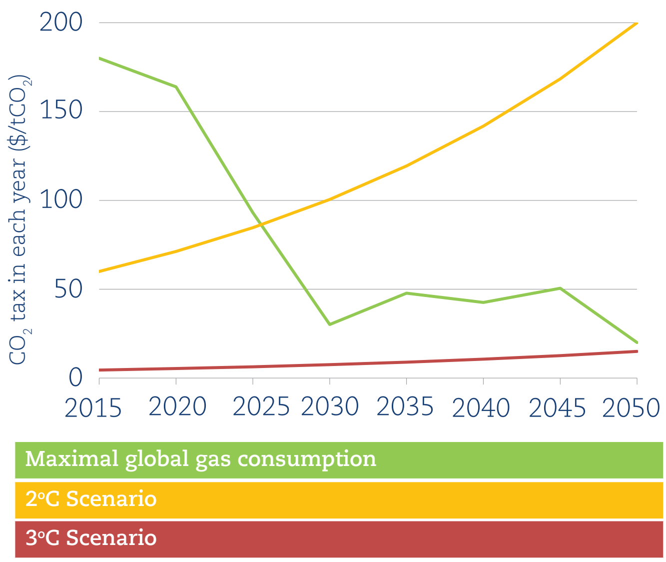


Figure 21. CO_2 taxes that maximise global gas consumption and the CO_2 taxes in the 2°C and 3°C scenarios



All other milestone years exhibit a peak at some level of CO_2 tax, as shown. For example in 2050 it is clear that there is a distinct peak in gas consumption at a CO_2 tax at $20/t$CO_2$. Figure 20 shows that a low CO_2 tax leads to higher maximum levels of gas consumption in later periods, while increasing the CO_2 tax causes the emissions in different periods to converge to a range of 4-5 Tcm/year, with the 2050 emissions falling fastest and furthest as the CO_2 tax increases.

An alternative manner in which to observe this is given in Figure 21. This figure shows the CO_2 tax level (on the y axis) that results in the highest level of gas consumption in each year (on the x axis) alongside the CO_2 taxes generated in the 2°C and 3°C scenarios. In other words, the 'maximal global gas consumption' line in Figure 21 plots the CO_2 tax rate of the peak in each of the lines shown in Figure 20 against the year in which it occurs.

Again, it can be seen that while a high CO_2 tax leads to higher gas consumption in near periods, in later periods the highest gas consumption arises with a lower CO_2 tax. From 2030 onwards, the CO_2 tax that leads to the highest levels of gas consumption averages just under $40/t$CO_2$, although it falls slightly in the final period. It is around 2025 that the CO_2 tax generated endogenously by TIAM-UCL in the 2°C scenario is closest to the tax rate that leads to the highest level of gas consumption across the scenarios with different tax rates. This suggests that if a global CO_2 tax were to be introduced that was commensurate with a 2°C scenario (which rises to around $200/t$CO_2$ as shown in Figure 21), this would lead, around 2025, to the highest level of global gas consumption that would be seen under any mitigation scenario, including those that reduce CO_2 emissions by much less overall. In contrast, it is not until 2050 that the much lower CO_2 tax that results in the 3°C scenario leads to the highest level of gas consumption across the mitigation scenarios.

What about the technology uncertainty that could affect the uptake of gas in the future? As discussed previously it is anticipated that a failure of CCS to commercialise could have important repercussions for the usefulness of gas in a carbon-constrained world. As will be discussed in the next section, the endogenously-calculated CO_2 taxes in the 2°C and 3°C are much higher when CCS is not permitted (over two and a half times higher in the 2°C scenario, at $550/t$CO_2$ and double in the 3°C scenario).

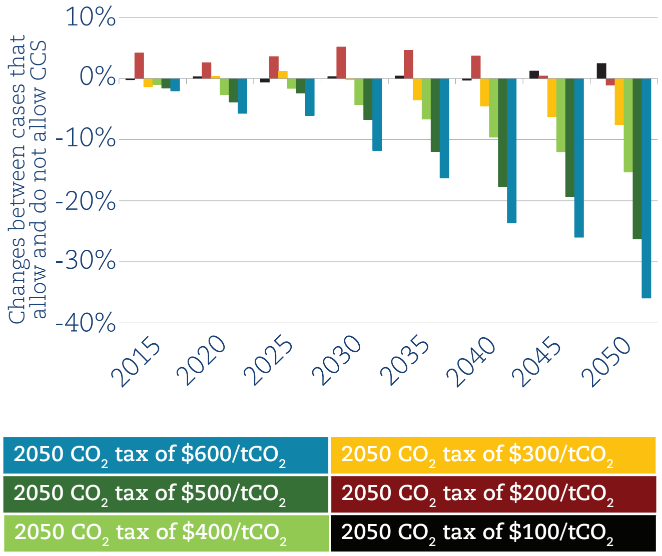
However, not only is the CO_2 tax much higher, which as demonstrated in Figure 19 generally means that gas consumption is lower in the long term, but also even at a given CO_2 tax level, consumption is generally lower when CCS is not available compared with an identical scenario when it is available. This is shown in Figure 22, which compares gas consumption between a number of different tax levels in scenarios that do allow CCS and those that do not. A positive percentage means that consumption is higher when CCS is not available, and a negative percentage that it is lower when CCS is not available. Up to 2025, the changes that are seen are all less than 5 per cent in all scenarios, and in the $100/t$CO_2$ case it can be seen that there is still little difference even in later years. However, at 2050 taxes of $300/t$CO_2$ and above, consumption is generally lower in scenarios that do not have CCS, and from 2030 onwards this reduction becomes increasingly more pronounced, especially at higher CO_2 tax levels.

The $200/t$CO_2$ tax scenario displays different behaviour, however. It can be seen that consumption is around 5 per cent higher in all periods up to 2040 when CCS is not available. Nearly all of this increase occurs in the electricity and transport sectors. There is obviously no biomass with CCS in the no-CCS scenario and it is now cost-effective to reduce further coal-based generation between 2015 and 2030 and use gas instead. From 2030-2040 there is also a greater uptake of CNG vehicles, particularly in the Middle East.

While the additional coal-to-gas switching before 2030 means that electricity emissions are slightly lower in the no-CCS case, the absence of (emissions-negative) biomass with CCS and the displacement of nuclear with gas means that CO_2 emissions from the electricity sector are around 2Gt/year higher when CCS is not permitted. Further, on an energy system-wide level at this CO_2 tax level, GHG emissions are around 10 Gt CO_2-eq (or 35 per cent) higher in 2050 when CCS is not available.

It is therefore important to remember that although a $200/t$CO_2$ tax in 2050 is the tax that TIAM-UCL suggests is required in the 2°C scenario when CCS is permitted, a $200/t$CO_2$ tax is certainly not sufficient if CCS is not available: as noted the tax must be $550/t$CO_2$ in 2050 in a 2°C scenario when CCS is not available.

Figure 22. Differences in gas consumption when CCS is and is not permitted



At the higher CO_2 tax levels, i.e. those that provide the emissions reductions more commensurate with a 2°C temperature rise, when CCS is not available gas is itself displaced from the electricity sector. The emissions from un-abated generation, and the associated cost penalty, mean that gas use in the electricity quickly ceases to be cost effective; the model instead relies on biomass and renewables.

In summary, Figure 22 suggests that CCS is generally very important in leading to a higher level of gas consumption in the future. This is particularly the case if the agreed temperature rises are not to be exceeded. The role of CCS is discussed in more detail in Section 6.

5.2 Regional level

Results have so far focussed on the global level; however there are many important underlying dynamics within different regions. This is shown in Table 9. Following a similar process to Figure 21, Table 9 provides the CO_2 taxes that lead to the highest levels of gas consumption within each of the regions indicated. Whilst it can be seen that some regions, such as the United States and Europe, generally follow the global pattern, others, such as Canada, exhibit very different behaviour.

In Canada, gas consumption is highest when there are never any CO_2 taxes imposed. This is because in any scenario with a CO_2 tax, there is a reduction in the demand for Canadian unconventional oil.

Table 9. CO_2 taxes that lead to the highest levels of regional gas consumption in different years and the CO_2 taxes in the 2°C and 3°C scenarios.

Region	CO_2 tax maximising gas consumption ($/$tCO_2$)		
	2020	2030	2040
AFR	7	10	20
AUS	157	20	20
CAN	0	0	0
CHI	107	151	80
CSA	64	0	0
Europe	164	101	40
FSU	100	10	60
IND	57	101	160
JPN and SKO	0	111	60
MEA	107	0	0
MEX	21	0	0
ODA	14	20	20
USA	150	60	20
Global	164	30	20
CO_2 tax level in 2°C scenario	70	100	200
CO_2 tax level in 2°C - no CCS scenario	165	250	550

Note: In this table, Europe comprises the previous WEU, EEU and UK regions with a single line also given to the combination of Japan and South Korea.

The production of natural bitumen requires a large amount of heat. This is generally provided by natural gas, and so if there is less demand for this type of oil, there will be less demand for gas.

In contrast in India, it can be seen that the CO_2 taxes that result in the highest levels of gas consumption are similar to those that are seen in the 2°C scenario. This suggests that maximising gas consumption in India is also most beneficial from a CO_2 emissions reduction perspective (because, as will be seen in the next section, the gas consumption substitutes in large part for the consumption of coal). These dynamics are explored in more detail in the following section, but it is evident that CO_2 taxes can have very different effects on different regions, and all do not follow the relationship observed globally.

[9] As noted in Section 2.1, to provide some context to the regional results, the proportions of 2011 electricity generation and primary energy supply that are coal, oil, gas, nuclear and renewables within each of the regions are outlined in the appendix.

5.3 Combining regional gas pricing and emissions reduction

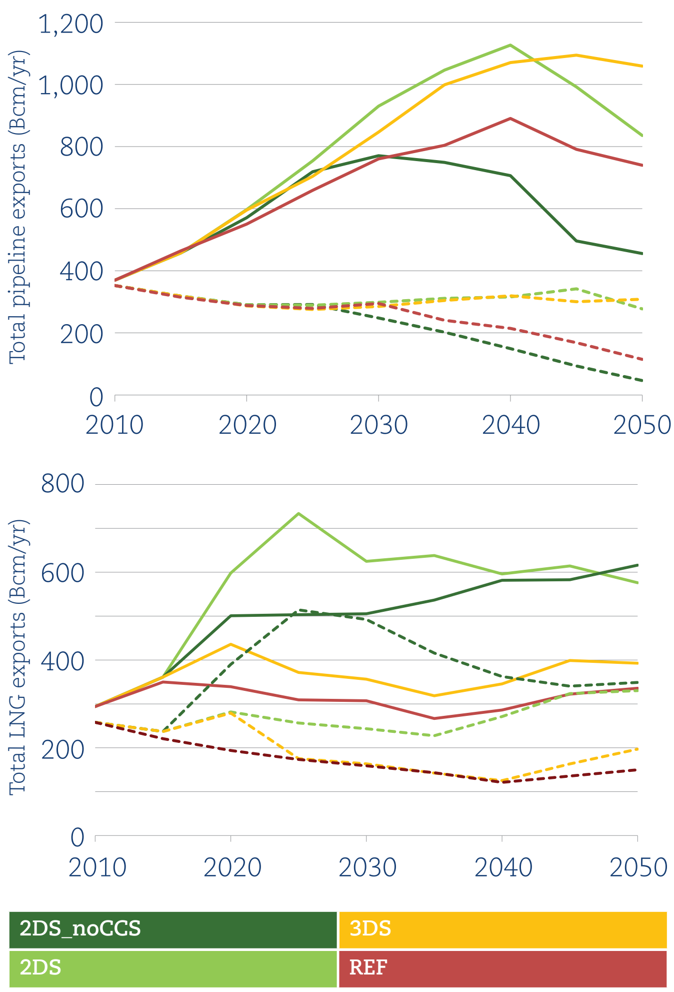
So far in this section, we have focussed on the way gas consumption varies with GHG mitigation policies. As we saw in Section 4.1, a continuation of gas pricing that is not based on supply and demand fundamentals (our 'regional gas prices' scenario), only led to a 4 per cent reduction in consumption on a global scale. However, it did have major impact on regional consumption levels and trade flows.

We can therefore combine uncertainty over future CO_2 policies with the uncertainty examined in the previous section regarding the pricing structure for gas and examine their relative impact on trade flows. This can be done by comparing LNG and pipeline flows under scenarios with different temperature targets and with different gas market structures.

These are presented in Figure 23. Dashed lines are total exports from scenarios resulting in the stated temperature rises with the 'regional gas pricing' structure and assumptions from Table 7, and bold lines the scenarios resulting in the stated temperature rises that have a 'global gas price'. The emissions reductions assumptions in both sets of scenarios are again identical to those in Table 8.

For both pipeline (top) and LNG (bottom) trade, results suggest that trade decreases in scenarios with the regional gas prices, regardless of the temperature constraint. This contrasts with what has actually been observed over the past few years, with an increasing amount of trade (inter-regional pipeline trade increased by 7 per cent between 2012 and 2010 and LNG trade by 10 per cent) at the same time as the divergent prices shown previously in Figure 6 have continued. There are a number of reasons why TIAM-UCL has not reproduced these results, but it is important to remember that the key goal of the model is to generate plausible long-term scenarios under the assumption of global surplus maximisation. It is unsurprising that it does not match results seen over the past few years as this is not what it aims to do. There are numerous factors, for example business cycles or concerns over energy security driving non-cost optimal decisions that will have been affecting trade dynamics over the short term that the model does not or cannot take into account. The model is, however, much better suited to give insights over the longer-term under the different potential scenarios discussed.

Figure 23. Total gas traded by pipeline (top) and LNG (bottom) under different emissions mitigation and market structure assumptions



Note: Dashed lines have 'regional gas pricing' and bold lines a 'global gas price'.

Looking first at pipeline trade (top of Figure 23), there is a distinct divergence between the two different market structures, but quite a close bunching for all differing emissions scenarios.

The global gas price (GLOBALGP) scenarios all rise to over 800 Bcm/year in 2030, while all of the regional-based pricing (REGIONALGP) scenarios decline to around 300 Bcm/year. The GLOBALGP scenarios then diverge: the 2°C (2DS) and 3°C (3DS) scenarios continue to grow to over 1000 Bcm/year by 2040, with a noticeable reduction after 2040 in 2DS. The reference case (REF) rises more slowly than these two scenarios, while the 2°C scenario without CCS (2DS_noCCS) declines back towards 400 Bcm.

With the REGIONALGP scenarios, pipeline trade in the reference case (REF_REGIONALGP) and 2DS_noCCS_REGIONALGP case continue to decline after 2030, while 2DS and 3DS rise slightly out to 2050. Nevertheless, it is evident that there is not nearly as large a spread in later periods as is the case with the GLOBALGP scenarios.

This figure indicates that the difference between any pair of scenarios with identical emissions reductions but different market structures is much greater than the difference between scenarios with identical market structures but different emissions reductions. For example, the difference in traded volumes in 2050 between 2DS_GLOBALGP and REF_GLOBALGP is 100 Bcm, while between 2DS_GLOBALGP and 2DS_REGIONALGP it is 560 Bcm.

This suggests that if gas-exporting countries want to expand (or maintain) pipeline gas exports, they should focus attention on altering their pricing policies, i.e. moving towards a global gas price and away from oil price indexation. This has a far greater impact on their level of gas exports than whether or not there is ambitious global emissions reduction agreement. However, if the market and pricing structure were to change, then until 2030, and potentially even longer if CCS is commercialised, the adoption of any ambitious emissions reduction agreement would result in little loss of markets, and could actually lead to a much greater level of exports.

Next looking at LNG volumes (bottom of Figure 23), again there is a lower level of exports with the REGIONALGP based scenarios. However, there is much less of a distinct trend for the scenarios with the two different market structures than was the case for pipeline volumes. For the GLOBALGP scenarios, REF and 3DS grow slightly in initial periods, but then remain at broadly similar levels from 2020 onwards (at an average of about 300 Bcm and 350 Bcm respectively). In contrast, LNG exports grow in the 2ºC scenarios, with a very rapid growth when CCS is not permitted and a steady but more monotonic growth when it is available. For the REGIONALGP scenarios, there is again a rapid rise in 2DS_noCCS up to 500 Bcm, but this is followed by a decline down to around current levels, while REF and 3DS decline in nearly all periods.

It is therefore evident that the 2ºC scenarios (both with and without CCS) have a larger level of LNG trade than REF and 3DS, regardless of the assumed market structure. Indeed exports are also nearly always larger when CCS is not available, while there is little difference between REF and 3DS.

Comparing these LNG results from all of the scenarios, there appears to be a very similar level of difference between pairs of scenarios with identical market structures but different emissions reductions and between pairs of scenarios with identical emissions reductions but different market structures. For example, the difference in LNG trade volumes in 2050 between 2DS_GLOBALGP and REF_GLOBALGP is 280 Bcm, while between 2DS_GLOBALGP and 2DS_REGIONALGP it is 285 Bcm. This is therefore a different situation than that seen for pipeline trade. These results therefore place equal importance on assumptions over emissions reduction and market structures for projecting future LNG trade.

However, a much clearer conclusion is that regardless of any changes to market structure, if countries want to expand their LNG exports, they should actively pursue an ambitious global agreement on GHG emissions mitigation. This arises mainly because of the significant role gas plays in replacing future coal demand in the emerging economies in Asia (particularly China), a market that is largely supplied by LNG.

5.4 Summary of results

This section examined the question: 'What policies lead to the highest level of gas consumption?' We primarily investigated the effect of GHG mitigation polices on overall levels of gas consumption. In near-term periods, the higher the CO_2 tax, the greater the level of gas consumption globally; however, by 2050, a CO_2 tax more commensurate with a 3ºC temperature rise leads to the highest level of gas consumption observed in that year in any scenario. This global pattern was not observed in all regions, however, and indeed some specific regions display very different behaviour. It was further found that CCS has an important effect of increasing gas consumption, even at low imposed CO_2 tax levels.

It was established previously that when a global gas price forms, regions in the European and Asian basins consume more gas but produce less domestically, while conversely exporting regions produce considerably more gas but noticeably reduce domestic consumption. As a result, there is only a slight increase in consumption globally, but more importantly that the assumed gas market structure can have a major effect on trade routes and flows. In this section, we further found that gas pipeline trade in the future is increased more through the establishment of a global gas price based on supply-demand fundamentals than by any specific level of future emissions reduction. In contrast for LNG trade, assumptions on emissions reduction and market and pricing structures are of equal importance for future projections.

We also demonstrated that scenarios that lead to a 2°C temperature rise have larger export volumes, both by pipeline and LNG, than those scenarios that lead to a higher temperature increases. For pipeline trade, the adoption of any ambitious emissions reduction agreement results in little loss of markets and could (if carbon capture and storage is available) actually lead to a much greater level of exports. For LNG trade, we concluded that export countries should actively pursue an ambitious global agreement on GHG emissions mitigation if they want to expand their exports. These results therefore have important implications for the negotiating positions of gas-exporting countries in the ongoing discussions on agreeing an ambitious global agreement on emissions reduction.

The Role of Gas in a Low-Carbon Energy System

6

This final results section now focuses discussion on the role of gas in a 2°C future, particularly its role as a 'bridge' or 'transition' fuel[10]. As mentioned previously, a 'relative' bridge is taken to be the period over which consumption is higher in a 2°C scenario than in a case with no emissions reduction policies (our reference case). An 'absolute' bridge is taken more simply to be the time when global or regional consumption rises from current levels in a 2°C scenario.

6.1 Global level

Gas consumption in the reference case (REF) was shown previously in Figure 10, but to show more clearly the changes in consumption within each region this is given numerically in Table 10. We have highlighted the year in which consumption in any region reaches a peak and subsequently enters a terminal decline.

Figure 24 next presents overall consumption on a global level in REF, and the 2°C (2DS) and 3°C (3DS) scenarios, which rely on the emissions reduction assumptions set out previously in Table 8. Figure 24 also provides the percentage changes between these scenarios.

Similar to REF, gas consumption in 3DS grows steadily over the model horizon. However, consumption is on average around 300 Bcm or 7 per cent greater in all years in 3DS relative to REF, although with a slightly larger difference in earlier periods.

In contrast in 2DS total consumption peaks in 2035 at just over 5 Tcm before subsequently declining. The maximum difference in consumption between 2DS and REF is just over 500 Bcm (between 2020 and 2025), or nearly 15 per cent greater than consumption levels in REF. With consumption continuing to climb in REF, this difference reduces over time so that by 2040 consumption is lower in 2DS. In the final period, there is a more noticeable drop, and consumption in 2DS finishes 20 per cent below that in REF.

The sectoral breakdown of consumption in 2DS is given in Figure 25. Figure 25 also displays the differences in consumption in each sector compared with REF (shown previously in Figure 12). As discussed in Section 4.1, consumption in REF was seen to grow in all sectors other than the electricity sector. In 2DS (the LHS of Figure 25) consumption in the electricity sector grows out to 2025 before declining (although still remaining above the consumption levels in REF), while the commercial and residential sectors decline from 2030 onwards. The declines in these three sectors as well as the plateauing of growth in the industrial sector account for the peak and subsequent decline in total consumption in 2DS. Consumption in 2DS is greater than REF in the electricity and industrial sectors in all years, however the commercial, transport and upstream sectors all require less gas in all periods. The residential sector is initially higher in early periods before falling in both relative and absolute terms in later periods.

Table 10. Gas consumption by region in a scenario in REF (in Bcm/year)

Region	2010	2015	2020	2025	2030	2035	2040	2045	2050
AFR	86	139	230	286	331	378	424	512	586
AUS	24	21	28	34	44	50	52	54	55
CAN	92	98	115	132	148	174	225	253	291
CHI	103	201	253	304	367	432	476	531	561
CSA	130	150	183	220	277	327	400	464	516
Europe	525	502	517	531	552	517	512	519	548
FSU	491	516	573	609	592	632	643	665	658
IND	58	104	175	202	230	259	270	264	283
JPN and SKO	135	146	157	151	151	140	127	115	102
MEA	297	374	423	529	600	668	732	785	811
MEX	56	54	53	57	68	93	128	164	172
ODA	150	202	233	281	342	409	486	541	612
USA	684	703	737	790	809	817	752	673	529
Global	2832	3211	3676	4126	4509	4897	5228	5541	5722

Highlighted cells in the table represent peak consumption.

[10] The assumptions contained within the scenarios presented in this section are tabulated in the Appendix.

The behaviour seen in Figure 24 and 25 shows a key result: on a global level, gas can play an important role as a bridging fuel both in relative and absolute terms up to 2035. However, there are a number of important caveats to this, upon which this result is very dependent. Global consumption of coal must be significantly reduced both from current levels and relative to the levels seen in REF in all time periods in a 2°C scenario. This can be seen in Figure 26, which presents primary energy consumption over time in 2DS, and the changes relative to the REF (shown previously in Figure 8). The line in the lower panel of Figure 26 shows the percentage increase in gas consumption relative to the drop in coal consumption (both in terms of EJ). A figure of 100 per cent means that the drop in coal consumption is entirely met by an equivalent increase in gas consumption, while 0 per cent means that gas does not contribute at all. It is immediately evident that in both absolute and relative terms coal consumption falls to a much greater extent than gas increases.

Gas offsets three quarters of the drop in coal consumption in 2015. It is clear, however, that at this time the reduction in coal consumption is quite small compared with the major drop seen in subsequent periods. The offsetting role of gas falls rapidly: even though gas consumption is nearly 15 per cent greater in 2DS than in REF in 2020 and 2025 (as shown in Figure 24) this only respectively offsets 30 per cent and 20 per cent of the much greater reduction in coal consumption. Subsequently, as the increase in gas consumption in 2DS relative to REF begins to fall, gas's contribution decreases even lower.

Figure 24. Global gas consumption (top) and changes relative to REF (bottom)

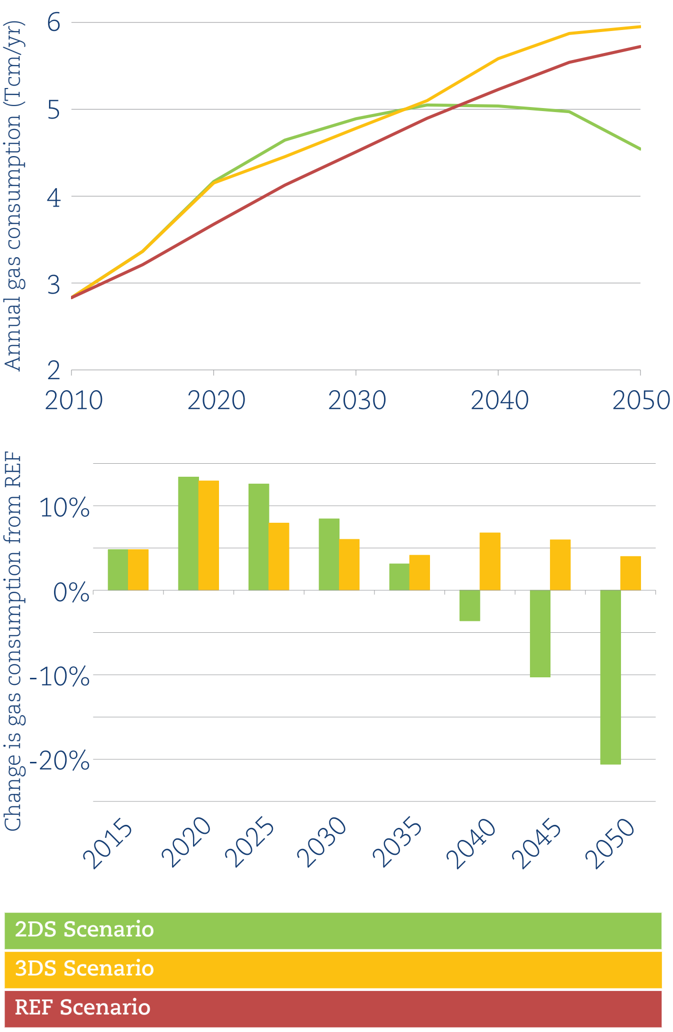


Figure 25. Global gas consumption in 2DS by sector and differences with REF

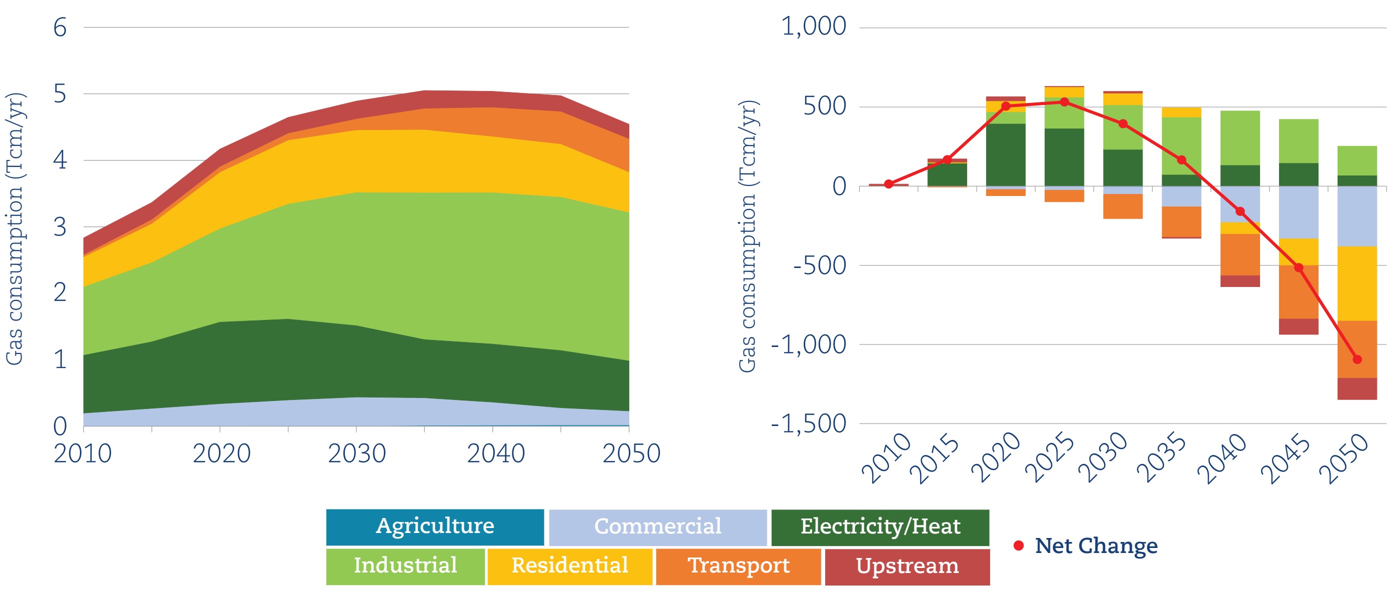


Figure 26. Primary energy consumption in 2DS, and changes relative to REF (shown previously in Figure 8)

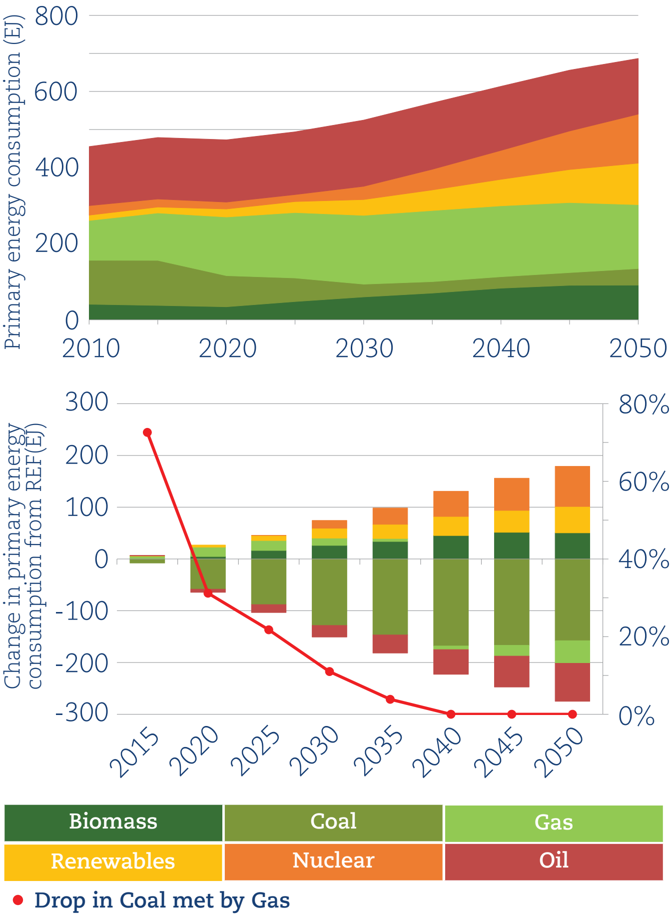
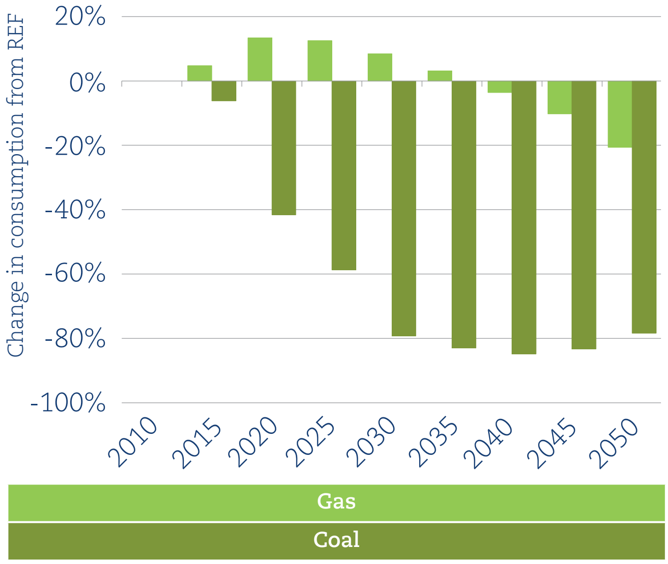


Figure 27. Percentage changes in coal and gas consumption in 2DS relative to REF



Eventually after 2035, when both gas and coal consumption are lower than in REF, gas obviously does not offset anything.

Shortly after 2020 nuclear, renewable electricity technologies, and biomass play a bigger role than gas in offsetting the drop in coal production. This role grows increasingly more important over time. These results therefore suggest that gas can only play a role in displacing coal up to 2020. Thereafter, while gas does continue to play some part in helping to fill the gap left by the huge reduction in coal consumption up to 2035, this is much less significant than the increases in zero or negative-carbon technologies.

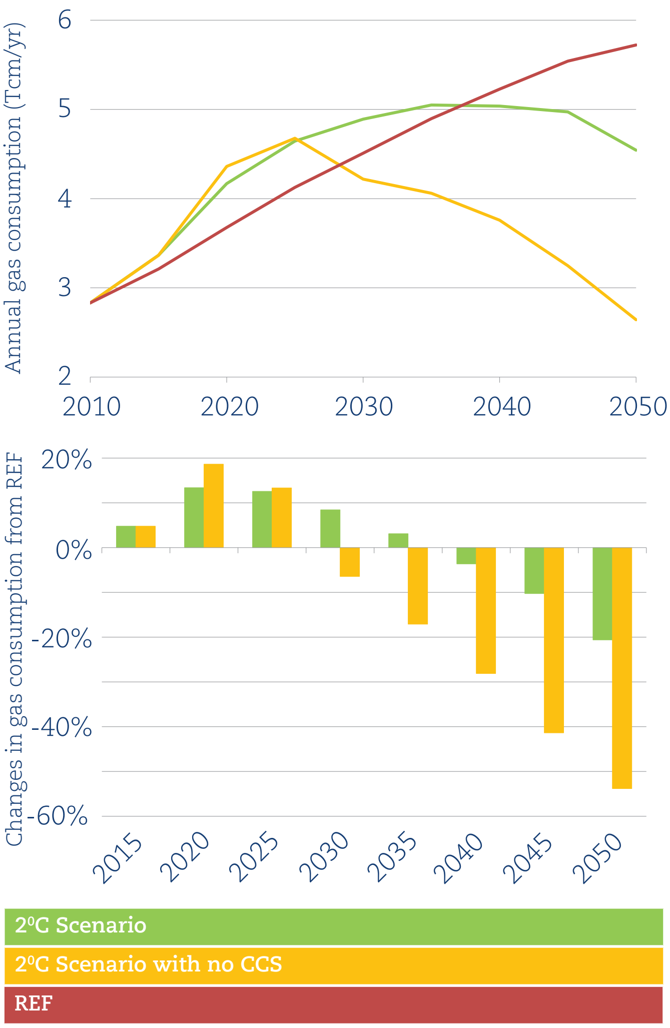
Perhaps the clearest way of visualising the relative bridging role of gas is shown in Figure 27, which isolates the percentage changes in coal consumption and the percentage changes in gas consumption between REF and 2DS over time. Coal consumption in 2020 in 2DS is 40 per cent lower than in REF, while, as mentioned above, gas is nearly 15 per cent greater. From 2025 onwards gas's relative increase falls while the reduction in coal consumption (again relative to REF) continues to grow to over 85 per cent. It is therefore again evident that coal production must be severely curtailed in all periods, and so the increase in gas consumption between 2015 and 2035 is in no way additional to increases in coal production. This brings out two very important elements of a 'gas transition' in a low-carbon scenario.

First, the bridging period is strictly time-limited. Gas consumption peaks and soon falls below the level in the non-mitigation scenario after 2035 and so to classify gas as a transition fuel, there must be a clear strategy how gas consumption can be at curtailed from this date.

Second, and even more important, the increased use of gas needs to be accompanied by an even larger decrease in coal consumption if the global temperature target is to be achieved. Again, any advocacy of gas as a transition fuel needs therefore to have a convincing narrative as to how global coal consumption can be curtailed. Otherwise it is likely that the emissions from the increased use of gas will be additional to those from coal, rather than being offset by an even greater reduction in coal use.

A third key factor in the bridging role that gas can play is the role of CCS. Figure 28 is similar to Figure 24, but this time includes the 2°C scenario in which CCS is not available (2DS_noCCS). In 2020 there is a slight difference between the two 2°C scenarios, with consumption actually slightly higher when CCS is not permitted. At its maximum, gas consumption is therefore almost 20 per cent greater than REF.

Figure 28. Primary energy consumption in 2DS, and changes relative to REF (shown previously in Figure 8)



However, absolute consumption in 2DS_noCCS peaks in 2025 at just over 4.5 Tcm, and then subsequently declines at an average of 2.3 per cent/year. Therefore by 2030, gas consumption falls below REF and thereafter consumption is significantly lower in all time periods. Indeed by 2050 it is over 50 per cent lower. The absence of CCS thus shortens the natural gas bridge in both absolute and relative terms by ten years, and also results in the subsequent need for a very rapid decline in consumption following this bridge. The commercialisation of CCS is therefore crucial for the future role of natural gas in a decarbonised energy system.

A fourth factor to bear in mind is that the definition of the 'relative' bridge given in Section 3.3.1 referred to the difference between a 2ºC scenario and a scenario with no GHG emission reduction policies. It is not necessarily the case, however, that this is the most appropriate comparative scenario. For example, given the commitments pledged as part of the Copenhagen Accord (UNFCCC 2009), it is unlikely that we are currently proceeding along a 'no policies' or 'reference' emissions pathway. Similarly a number of air quality and fuel efficiency standards have been introduced internationally (see e.g. European Parliament & Council of the European Union (2008)), which may not have the explicit intention of mitigating GHG emissions, but are still likely to result in some emissions reduction, and importantly coal consumption. It could therefore be argued that alterative scenarios such as the IEA's 'Current Policies' or 'New Policies' scenarios provide a more appropriate comparison (IEA 2013c).

We chose to use a 'no policies' scenario to be most explicit about the relevant assumptions. However, as was discussed in Section 4, coal production is extremely prevalent in this scenario, and indeed some regions that are currently trending away from coal-based electricity generation construct a number of new coal power plants. This could be considered unrealistic. If so, it may be the case that the 3ºC scenario is a better scenario with which to compare gas consumption in the 2ºC scenario. As noted in Section 5.1, 3DS results in a significantly lower level of coal consumption than in REF.

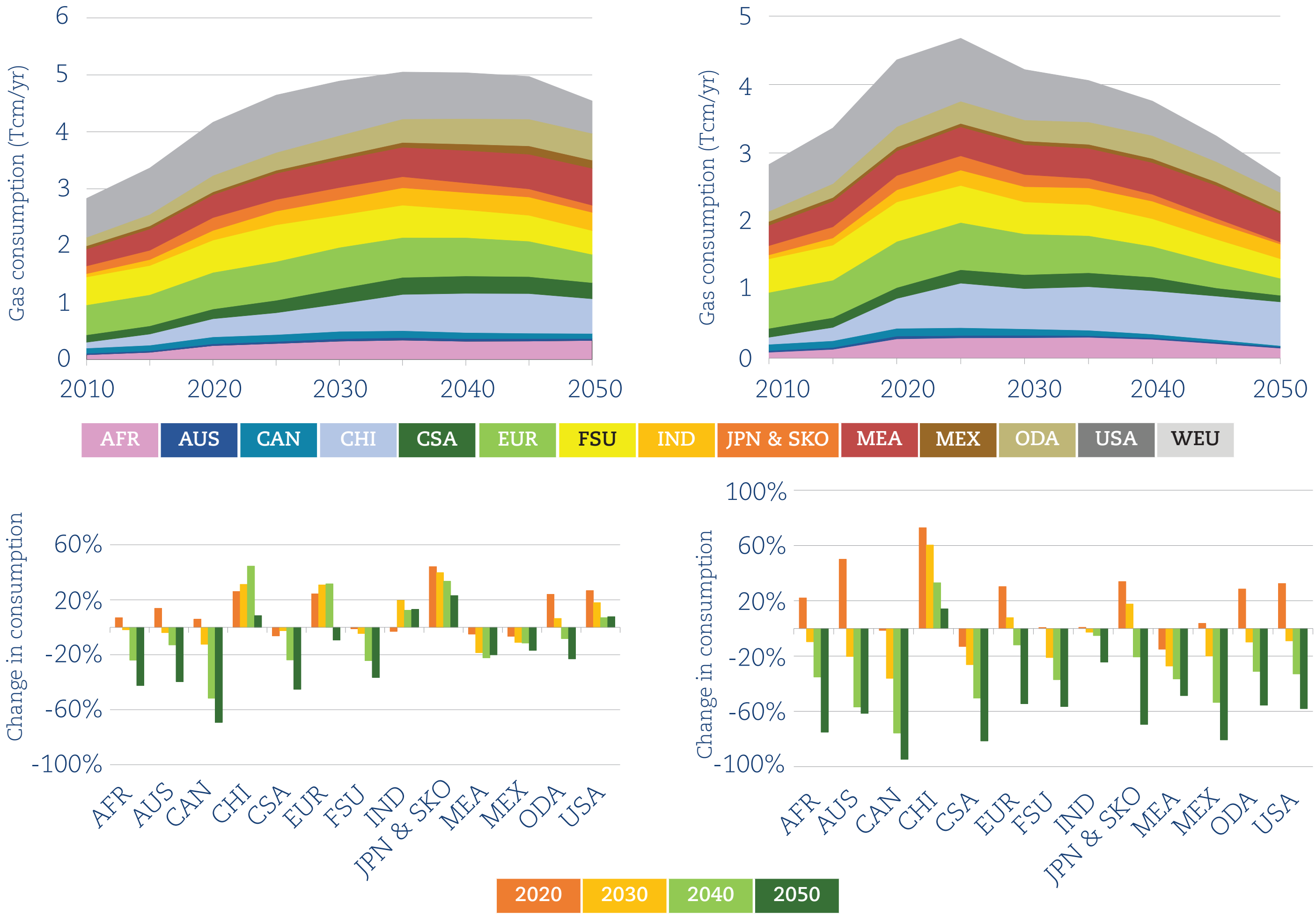
Consumption in 3DS was shown in Figure 24. While gas still acts as a 'relative' bridge in 2DS when compared to 3DS, this is to a much lesser degree. The maximum difference between these two scenarios is lower (4 per cent in 2025), and indeed after 2030 consumption in 2DS is lower than in 3DS. Further, there is no increase in gas consumption above 3DS until 2020. The 'relative' bridge formed by natural gas is thus shortened to 10 years (between 2020 and 2030) and the advantage (from a climate perspective) conveyed by consuming additional gas is significantly diminished.

6.2 Regional level

The final caveat in understanding the potential for gas to act as a transition fuel is that global level results do not necessarily describe particularly well the underlying variation between different regions. Figure 29 shows results at a region level: first absolute consumption split in 2DS, and then the relative changes in consumption between REF and 2DS. It is immediately apparent that gas has a very different role to play in different regions. For example, gas consumption in China is greater in all periods in 2DS and is nearly 50 per cent greater in 2040 (at around 700 Bcm).

Figure 29. Absolute gas consumption by region in 2DS, and changes between 2DS and REF

Figure 30. Absolute gas consumption by region in 2DS_noCCS, and changes between this scenario and REF



Note: Europe (EUR) includes UK and Japan and South Korea (JPN & SKO) are combined.

On the other hand, gas consumption in Central and South America (CSA), the Middle East (MEA), and Mexico (MEX) is lower in all periods in 2DS. Consumption is reduced in all three of these in a number of sectors (electricity, upstream, and residential), but interestingly the largest change occurs in the transport sector, with hydrogen being preferred over CNG in medium goods vehicles.

Table 11 accompanies Figure 29, and provides actual consumption figures, while also highlighting the year in which consumption peaks and subsequently declines terminally within any region (if this occurs). The peak in consumption in the USA moves forward by 10 years (from 2035 in REF), and peaks appear in a number of regions that did not exhibit one previously.

As with the global-level results, the failure of CCS to become available also has a significant effect on regional consumption levels. This is demonstrated in Figure 30, which, similar to Figure 29, presents absolute production split by region in 2DS_noCCS, and the changes compared to REF. In 2020, a number of regions (particularly Australia and China) increase consumption by an even greater than when CCS was available. However, by 2040 only China has gas consumption greater than in REF. All other regions have reduced consumption, in many cases by quite a substantial degree.

Table 12 again numerically presents the absolute production figures and highlights the peak production years within each region if this occurs. While consumption still does not peak in all regions, in general the peaks occur earlier in this scenario than either REF or 2DS (with CCS). The peak for the United States, for example, moves further forward to 2020, and European gas consumption peaks in 2025 rather than 2030 in the 2°C scenario when CCS was available.

Table 11. Absolute gas consumption by region in 2°C scenario including dates when regional consumption peaks (highlighted cells) (all figures in Bcm/year)[11]

Region	2010	2015	2020	2025	2030	2035	2040	2045	2050
AFR	86	129	246	284	324	342	322	326	337
AUS	24	27	31	35	43	45	45	44	33
CAN	92	98	121	121	129	122	109	95	89
CHI	103	196	319	383	482	636	688	695	609
CSA	130	143	171	218	270	299	305	298	283
Europe	525	547	643	681	723	701	675	623	497
FSU	491	513	567	645	566	567	487	455	418
IND	58	105	170	240	275	305	304	320	320
JPN and SKO	135	163	226	204	211	195	169	143	125
MEA	297	375	402	460	489	517	569	608	648
MEX	56	54	49	53	60	84	113	147	143
ODA	150	202	289	313	364	413	446	472	471
USA	684	814	934	1008	955	823	805	747	570
Global	2832	3365	4169	4645	4891	5049	5037	4972	4543

Table 12. Absolute gas consumption by region in the 2°C scenario that does not allow CCS including dates when regional consumption peaks (highlighted cells) (all figures in Bcm/year)

Region	2010	2015	2020	2025	2030	2035	2040	2045	2050
AFR	86	129	281	296	298	304	275	212	146
AUS	24	27	41	34	35	24	22	22	21
CAN	92	98	113	114	94	80	54	35	15
CHI	103	196	437	651	588	636	633	638	640
CSA	130	143	159	196	204	204	199	119	96
Europe	525	547	675	691	596	543	450	362	249
FSU	491	513	578	541	467	455	404	350	286
IND	58	105	176	225	223	245	256	236	214
JPN and SKO	135	163	210	209	177	137	101	69	31
MEA	297	375	359	423	436	440	464	481	417
MEX	56	54	55	50	54	59	59	51	33
ODA	150	202	300	325	308	327	335	298	272
USA	684	814	978	921	736	607	504	375	222
Global	2832	3365	4361	4677	4218	4060	3758	3248	2643

Note: Europe (EUR) includes UK and Japan and South Korea (JPN & SKO) are combined.

Insights can now be drawn on the role of natural gas as a transition fuel in the 2°C scenarios in each region. These are summarised in Table 14. This table indicates the latest year to which gas acts as a relative bridge (since in all case the bridging period commences in 2010), the latest year to which gas acts as an absolute bridge, and the percentage by which consumption is greater when the difference between consumption in the 2°C scenario and REF is at its maximum value.

This maximum relative increase is important as provides a proxy for the magnitude of the role played by gas; in other words it describes the 'height' of the bridge. Table 14 also separately considers the 2°C scenarios with and without CCS.

[11] As noted previously, results from this table (as with all others) should not be interpreted as a forecast. The results seen here assume that countries will meet their Copenhagen Accord emissions reductions and will work (from 2015) towards mitigating the temperature rise to 2°C in the most cost-optimal manner. It is, for example, unlikely that gas consumption in Europe will be higher in 2015 than in 2010.

Table 13. Criteria by which duration & magnitude of natural gas bridge in each region is judged

Criteria	Description	Score	Colour in Table 6.5
Duration of absolute bridge	Lasts until 2040 or later	2	Green
	Lasts until between 2020 and 2040	1	Orange
	Lasts only up to and including 2020	0	Red
Duration of relative bridge	Lasts until 2040 or later	2	Green
	Lasts until between 2020 and 2040	1	Orange
	Lasts only up to and including 2020	0	Red
Maximum relative increase	Greater than 30 per cent	2	Green
	Between 10 per cent and 30 per cent	1	Orange
	Less than 10 per cent	0	Red

Criteria	Score	Description of potential role for natural gas	Name in Table 6.5	Colour in Table 6.5
Strength of bridge	5-6	Extended and strong potential role to act as a transition fuel	Strong	Green
	3-4	More diminished but still maintains a good potential to act as a transition fuel	Good	Orange
	<2	Very limited or no potential role to act as a transition fuel	Limited	Red

Table 14. Years to which natural gas acts as a bridge in 2°C scenarios, both in absolute terms and relative to REF, the percentage consumption is above REF at its maximum value, and therefore the potential role gas can play as a transition fuel in each region.

	With CCS				Without CCS			
Region	Period over which acts as a relative bridge	Maximum difference in consumption	Period over which acts as an absolute bridge	Potential role to act as a transition fuel	Period over which acts as a relative bridge	Maximum difference in consumption	Period over which acts as an absolute bridge	Potential role to act as a transition fuel
AFR	2020	7%	2050	Limited	2025	22%	2035	Good
AUS	2025	24%	2040	Good	2025	50%	2020	Good
CAN	2020	6%	2030	Limited	N/A	0%	2025	Limited
CHI	2050	45%	2045	Strong	2050	114%	2050	Strong
CSA	N/A	0%	2040	Limited	N/A	0%	2030	Limited
Europe	2045	36%	2030	Strong	2035	30%	2025	Good
FSU	2025	6%	2035	Limited	N/A	1%	2020	Limited
IND	2050	21%	2050	Strong	2025	11%	2040	Good
JPN and SKO	2050	44%	2030	Strong	2030	38%	2020	Good
MEA	N/A	0%	2050	Limited	N/A	0%	2045	Limited
MEX	N/A	0%	2045	Limited	N/A	4%	2040	Limited
ODA	2035	24%	2050	Good	2025	29%	2040	Good
USA	2050	28%	2025	Good	2025	33%	2020	Good
Global	2035	13%	2035	Good	2025	19%	2025	Good

To demonstrate results more clearly, and to differentiate between the potential roles in each region, we have assigned scores to the duration of the relative and absolute bridges and the level of the maximum relative increase (if any). These criteria are set out in Table 13 and the values in Table 14 have been coloured to reflect these. Finally, the scores from each criterion are combined into a single value with equal weighting attached to each. The maximum score a region can thus achieve is six and the minimum zero.

We now interpret the role that natural gas can play in each region based on this total; this is also shown in Table 13. If a region scores five or more we conclude that there is an extended and strong role for natural to act as a bridge or transition fuel; if it scores either three or four then gas has a more diminished role in a decarbonised energy system but still maintains a good potential to act as a transition fuel; if it scores two or less then there is a very limited or no role of gas to act as a transition fuel. The qualitative description of the role gas can play is thus also included in Table 14. These are admittedly somewhat subjective criteria and scores, however they span the full range of results, and provide a good overview of the manner in which natural gas can be seen to be acting in each region in Figures 29 and 30.

When CCS is available, natural gas plays an important or strong bridging role in four regions: China, Europe, India and Japan and South Korea. Its role as a transition fuel in the United States is also evident, but consumption falls in absolute terms from a relatively early stage. In contrast in Other Developing Asia and Australia, absolute gas consumption rises for a longer period than in the United States, but this drops below the growth in consumption in REF at an earlier stage. In the United States, Other Developing Asia and Australia, we therefore conclude that gas has good potential to act as a bridging fuel, but that this is more limited than in some other regions.

In other regions, such as Africa, Central and South America, the Middle East and Mexico, gas consumption does continue to rise in 2DS out to late periods (after 2040). However, consumption rises faster in REF. Finally, in Canada and the Former Soviet Union, absolute consumption and relative is lower before 2035, and the maximum difference in consumption is very small.

We therefore interpret this to mean that pursuing policies encouraging the consumption of additional natural gas in these regions would be detrimental from a climate perspective and so gas has no or only a very limited potential to act as a transition fuel.

The influence of CCS is clear from Table 14; only in China does gas maintain its strong potential role when CCS is not available, indeed this role even appears to be strengthened. However, similar to the result at a global level, in nearly all other regions, despite the fact that the increase in consumption relative to REF is generally higher, the duration over which gas acts as a bridge is shortened. A number of the regions that had a ‘strong’ potential role for gas when CCS was available consequently drop down to mid-level. The only exception is Africa, which moves upwards. When CCS is not permitted, electricity generation from coal (which is predominantly in South Africa) ceases immediately in 2020 and is replaced by gas generation.

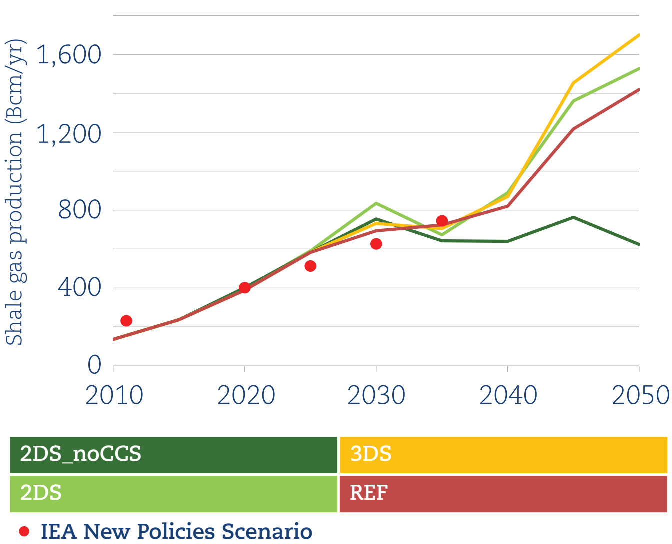
When CCS was permitted, the coal power plants continued operating until 2030 and so slightly less gas was required. It is again important to highlight that all of these results are dependent upon coal consumption dropping drastically from current levels in all regions.

6.3 Effects of climate policy on shale gas production

The last area we examine is the effect that climate policy has on global shale gas production. Global shale gas production in each of the temperature scenario is given in Figure 31, which also contains the shale gas production projection from the latest IEA New Policies Scenario (IEA 2013c) for reference. As noted previously, the IEA indicates that this scenario is likely to lead to a long-term average 3.6°C temperature rise. All scenarios can be seen to match closely the IEA projection up to the latest date given (2035). Indeed, REF, 3DS, and 2DS are broadly similar over the whole model horizon, with all three leading to global shale gas production that exceeds 1.4 Tcm by 2050.

When CCS is not permitted, the projection in shale gas production remains similar to the others up to 2030 but thereafter remains steady at an average just under 700 Bcm/year. The main difference lies in production from Central and South America, where production grows out to 2030 but then declines to negligible levels rather than continuing to grow out to 2050, and Mexican production, which remains on a plateau of 35 Bcm/year rather

Figure 31. Global shale gas production in each scenario and projections from the latest IEA New Policies Scenario



than growing to over 200 Bcm/year by 2050 as in the other scenarios.

It should be noted that these results are very sensitive to the relative cost assumptions of shale gas compared with other conventional and unconventional sources. Further, we assume that fugitive emissions from shale gas production are only 5 per cent higher than the equivalent fugitive emissions for conventional production (these are emissions from production only and do not take account of the potential for the fugitive methane emission that occur during transport and distribution by pipeline as discussed in Section 2.4.1). This is an area of ongoing controversy (see e.g. AEA 2012), but at present there are no sufficiently robust data to characterise this uncertainty to a suitable degree.

Shale gas production in the UK also remains largely unaffected by the emissions reduction target. In all scenarios production first commences in 2015 and grows to 6.5 Bcm in 2020. Thereafter production peaks at around 20 Bcm in 2030 before declining to negligible levels by 2040 as the assumed sweet spot areas become exhausted and it is more cost-effective to import gas from elsewhere. The peak in production is, however, marginally higher (2 Bcm/year) in both 2°C scenarios.

6.4 Summary of results

This section focussed on investigating the role of natural gas in a de-carbonised energy system. In a scenario that provides a 60 per cent chance of limiting the average surface temperature rise to 2°C, gas consumption rises until 2035, and indeed is larger than in a case with no GHG emissions reductions on a global level between 2015 and 2035. We therefore consider that there is a good potential for gas to act as a transition fuel to a low-carbon future up to 2035. A number of important caveats were discussed to this, however.

First, the bridging period is strictly time-limited. Global gas consumption declines in all years after 2035 whilst it continues to rise in scenarios leading to higher average temperature rises. Therefore any increase in near-term periods must be followed by a subsequent reduction in later periods; this will likely have a number of important business and policy implications.

Second, the absolute and relative increase in gas consumption (between the scenario limiting the temperature rise to 2°C and one with no GHG emissions reductions) must occur alongside a much greater reduction in coal consumption again in both absolute and relative terms. For example, in the 2°C scenario gas consumption increased by almost 15 per cent relative to the case with no GHG emission reductions (in 2025), but at the same time coal consumption was over 60 per cent lower, and fell to an average more than 80 per cent lower in all periods thereafter. This also has very important policy implications: any encouragement of gas to play a bridging role to a low-carbon, low-warming future must be accompanied by a stringent reduction in coal consumption, and its replacement by low-carbon, non-gas energy sources. Gas in this case is a short-term complement to the much larger increase in low-carbon energy sources that needs to take place for the low-carbon transition actually to be achieved.

Third, carbon capture and storage (CCS) is of particular importance. In a 2°C scenario in which CCS is not available, gas consumption peaked in 2025 and declined terminally thereafter: the role that gas can as a transition fuel play was thus substantially reduced.

Fourth, our definition of the 'relative' bridging role that gas could play refers to the difference between a 2°C scenario and a scenario with no GHG emission reduction policies. In such a scenario there is a reversal of the trend that is currently being exhibited in many regions away from coal-based power generation. A scenario with no GHG emissions reduction may not therefore be the best choice for comparison. If a scenario is chosen that results in a lower temperature rise or contains a non-zero global CO_2 tax, for example a 3°C scenario, then the advantage (from a climate perspective) conveyed by consuming additional gas role is significantly lessened.

The fifth and final caveat is that this global pattern was not exhibited by all regions, with gas able to play a bridging role in some regions but not in others. Of the 13 regions studied, gas had limited or no potential to act as a transition fuel in six (Africa, Canada, Central and South America, the Middle East and Mexico), a good potential in three (Australia, Other Developing Asia, and the United States), and a strong potential in four (China, Europe, India, and Japan and South Korea). Again this is dependent on the availability of CCS, with natural gas only remaining a strong bridge in China if CCS is not available.

Finally, we found that there was very little difference in shale gas production levels under different long-term emissions mitigation targets. Production in a 2°C scenario was very similar to that in a 3°C scenario and indeed a 5°C scenario, exceeding 1 Tcm/year in all not long after 2040.

However, in a 2°C scenario that did not allow CCS, shale gas grew to just under 700 Bcm/year by 2030, still a significant level of growth from present, but then remained at approximately this level until 2050. These results are, however, sensitive to the relative cost assumptions of shale gas compared with other conventional and unconventional sources and to the assumed levels of fugitive emissions from shale gas production. This final issue is an area of particular ongoing controversy, but both areas require significant further research before it can really be concluded that shale gas has an important role to play in the transition to a low-carbon global energy system.

Conclusion and Wider Implications for Gas Markets

7

This project has brought together two strands of UK Energy Research Centre research: energy system modelling using the global TIAM-UCL model, and geopolitical economy research that has been examining the development of the global gas market. This enabled us to modify assumptions and characterise scenarios within the model to focus on the key drivers that will influence supply of and demand for natural gas in the future, and to explore its potential role as a bridging fuel. These drivers included:

1. the influence of market structure and the pricing of internationally traded gas on future supply, demand and trade;
2. the impact of climate change mitigation policies on future gas demand; and
3. the availability of carbon capture and storage (CCS) in both increasing and extending natural gas demand within the constraints of a 2°C mitigation strategy.

The analysis first indicated that natural gas can play an important role as a transition fuel to a low-carbon future on a global level. However, it highlighted that there are key regional differences in the potential for natural gas to perform this bridging role and that the window of opportunity offered by gas is strictly time-limited. Put simply, our findings suggest that – in a world where strong mitigation measures are taken to limit global warming to 2°C – it won't be a golden age for gas everywhere and it won't be long before natural gas consumption becomes part of the problem rather than part of the solution. This final section considers the wider implications of the project's findings in relation to the three drivers identified above.

The findings of our research suggest that global price formation convergence is necessary to promote increased natural gas consumption and international trade. By this we do not mean that the price of natural gas will be the same in the major regional markets (North America, Europe and the Asia-Pacific), rather that gas price formation in these markets will be based on gas-to-gas competition and the laws of supply and demand. This is not the case at the moment and this helps to explain the significant levels of price divergence that we see at present.

The price will not be same in each regional market as it will reflect differences in production costs, scarcity rents and transport costs. Thus, for example, LNG prices will likely remain higher because of the capital intensity of the supply chain and the costs of liquefaction and transportation. The key point is that this 'global' price results in a lower gas price in key markets – such as China – where gas demand can only grow if it is competitive with coal in power generation. Similarly, in Europe pipeline gas must be able to compete against coal (in the absence of an effective carbon trading system). Put another way, in both instances, oil indexation – under present market conditions – results in too high a gas price in key markets. At present, the position of key gas exporters, such as Russia and the other members of the Gas Exporting Countries Forum, is to defend oil-indexation in the belief that this will protect short-term revenues. Our analysis suggests that in the longer-term this is self-defeating, as it will constrain demand for natural gas. This is particularly the case for LNG that is aimed at those emerging Asian economies that might otherwise consume a lot more coal.

It is, however, also worth noting that regardless of how gas is priced in the future, when GHG emissions reductions are taken seriously, pipeline and LNG exports are larger, and often much larger, than when GHG emissions are ignored. Gas-exporting countries should therefore note that actively pursuing an ambitious global agreement on emissions reduction could be a beneficial and worthwhile method by which they could open new markets and increase export levels in the future.

This leads onto another key result, which is that strong climate change mitigation polices promote increased gas demand in the near term. This is because the focus of early mitigation is on removing coal from the energy mix. However, there comes a time, which varies dependent on the level of carbon tax and the region in question, when natural gas itself must be removed from the energy mix because GHG emissions are no longer compliant with reduction targets. Thus, sometime between the 2020's and 2030's there will no longer be a role for substantial amounts of unabated gas power generation.

In mature markets, where gas is part of base load, it is understood that the role of natural gas must rapidly evolve to being primarily a backup for renewable intermittency. In such a context significant gas power generation capacity remains online, but the load on that capacity is significantly reduced. At the same time, residential use of gas for cooking and heating must be replaced by low carbon electricity.

In emerging markets, where the hope is that new gas power generation is constructed instead of coal, it may be that that capacity will have to be retired long before it becomes obsolete. The fear of some is that building that capacity to meet the relatively short-lived 'bridging' role will lock in a higher carbon energy mix since industry will not retire serviceable equipment. However, it is worth noting that industry is already having to do this to coal-fired plant in Europe under pollution control directives.

What is therefore required is a 'gas-by-design' approach. This would understand the time-constrained role for natural gas in the low-carbon transition and so create a business model that enables sufficient investment in gas power capacity while it is needed, but also ensure that it is withdrawn when it is no longer consistent with emissions targets and/or modified such that it runs as back up for renewables. Such an approach would also provide some insurance against a failure to build sufficient low-carbon capacity in time.

The final key finding of our analysis is the critical role of CCS. Simply put, the large-scale commercial deployment of CCS enables gas to remain in the power generation mix and in the industrial sector for much longer, and so allows higher absolute levels of gas consumption. Furthermore, there are a number of regions where CCS is crucial for gas to play a bridging role. This suggests that the gas industry and gas exporting and consuming countries should make much greater efforts to bring flexible gas power with CCS to market as soon as possible. The only caveat is that CCS can also be fitted to coal-fired power stations; however, there is much more carbon to be captured and stored in the case of coal.

This analysis has been global in scope and as such is a broad-brush approach to the prospects for natural gas to play a role as a bridge to a low carbon future. It identifies significant limitations to that role and suggests key factors that could increase future gas demand and international trade. We have not examined the case of the UK in any detail. The next stage in our research is to ask the same questions using a model appropriate to the UK. Earlier UKERC research (Skea *et al.* 2011) suggests a modest role for gas in the future. These findings require renewed scrutiny given the assertions that shale gas development in the UK is consistent with our climate change policy.

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8

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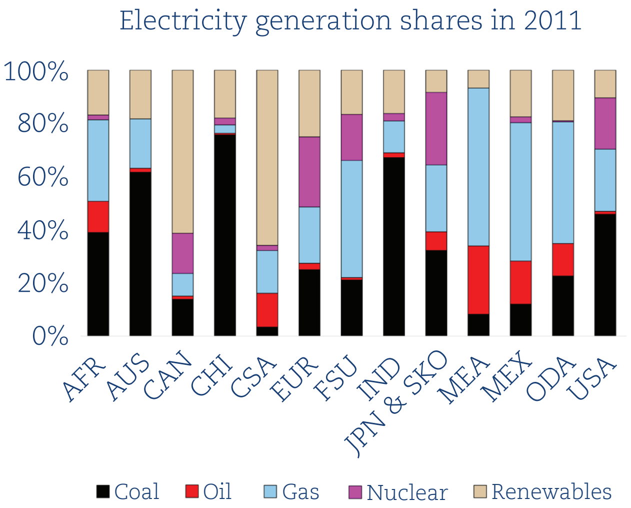
Appendix

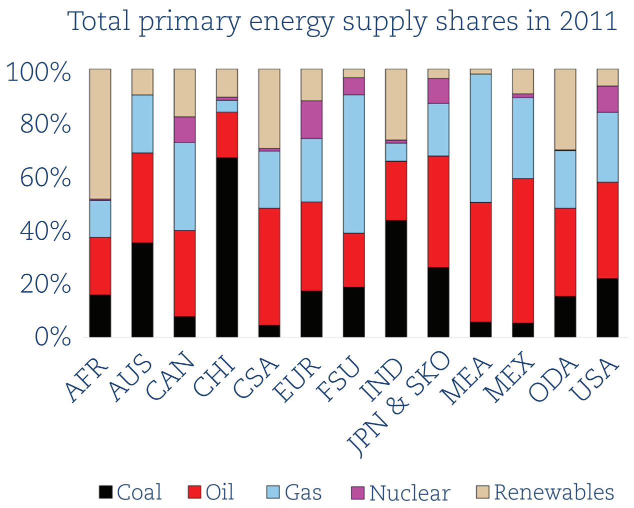
9

Summary of all scenarios with key assumptions

Scenario name	Main section	Gas pricing assumptions	GHG or CO_2 assumptions	Other assumptions	Other comments
REF_GLOBALGP	4.1, 5.3	Global gas price	Keep temperature rise below 5°C in all years	-	Identical to REF used in section 6
REF_ REGIONALGP	4.2	$3/MMBTU cost markup to gas traded into Europe $5/MMBTU cost markup to Asian regions	Keep temperature rise below 5°C in all years	-	-
CO_2 tax rising to between $0-$500/tCO_2	5.1, 5.2	Global gas price	CO_2 tax in 2015 rising at 3.5 per cent/year to level in 2050 & rising thereafter	-	-
CO_2 tax rising to between $0-$500/tCO_2 no CCS	5.1, 5.2	Global gas price	CO_2 tax in 2015 rising at 3.5 per cent/year to level in 2050 & rising thereafter	-	-
3DS_GLOBALGP	5.3	Global gas price	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 3°C in all years	-	Identical to 3DS used in section 6
2DS_GLOBALGP	5.3	Global gas price	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 2°C in all years	-	Identical to 2DS used in section 6
2DS_noCCS_ GLOBALGP	5.3	Global gas price	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 2°C in all years	No CCS technologies	Identical to 2DS_ noCCS used in section 6
REF_ REGIONALGP	5.3	$3/MMBTU cost markup to gas traded into Europe $5/MMBTU cost markup to Asian regions	Keep temperature rise below 5°C in all years	-	-
3DS_ REGIONALGP	5.3	$3/MMBTU cost markup to gas traded into Europe $5/MMBTU cost markup to Asian regions	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 3°C in all years	-	-
2DS_ REGIONALGP	5.3	$3/MMBTU cost markup to gas traded into Europe $5/MMBTU cost markup to Asian regions	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 2°C in all years	-	-
2DS_noCCS_ REGIONALGP	5.3	$3/MMBTU cost markup to gas traded into Europe $5/MMBTU cost markup to Asian regions	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 2°C in all years	No CCS technologies	-
REF	6	Global gas price	Keep temperature rise below 5°C in all years	-	-
3DS	6	Global gas price	2010- 2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 3°C in all years	-	-
2DS	6	Global gas price	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 2°C in all years	-	-
2DS_noCCS	6	Global gas price	2010-2015 Copenhagen Accord emissions reductions 2015- keep temperature rise below 2°C in all years	-	-

Existing regional electricity generation and primary energy supply shares





Africa – AFR; Australia and New Zealand – AUS; Canada – CAN; Central and South America –CSA; China – CHI; Europe – EUR; Former Soviet Union – FSU; India – IND; Japan and South Korea – JAP & SKO; Mexico – MEX; Middle East – MEA; Other Developing Asia – ODA ; United States – USA.

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