Climate implications of coal-to-gas substitution in power generation

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, or by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Cooperation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

IEA Clean Coal Centre began in 1975 and has contracting parties and sponsors from: Australia, Austria, China, the European Commission, Germany, India, Italy, Japan, New Zealand, Poland, Russia, South Africa, Thailand, the UK and the USA. The Service provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

Coal is the most widely used primary energy source in power generation, with 36% share in 2014 of globally generated electricity. There is currently a trend of substituting coal with natural gas in some parts of the world. Natural gas combustion produces about half the greenhouse gases compared to coal. However, in recent years, several studies considered the implications of methane emissions on climate change in large scale switching from coal to gas for electricity generation. Methane (CH_4) is a hydrocarbon and the primary component of natural gas. It is more potent than carbon dioxide (CO_2) as a greenhouse gas (GHG), and therefore is a significant contributor to climate change, especially in the near term (10–20 years). The studies have found that methane emissions from gas exploration, extraction, transmission and distribution, unless controlled, could make the benefits of coal to gas substitution, questionable, especially so in the short term. This report reviews these publications and their findings.

Acronyms and abbreviations

AGA	American Gas Association (USA)
API	American Petroleum Institute (USA)
ANGA	America's Natural Gas Alliance (USA)
BC	black carbon
Bm^3	billion cubic meters
BTEX	benzene, toluene, ethyl benzene and xylene
BUI	business as usual
C2ES	Centre for Climate and Energy Solutions (USA)
CBG	coalbed gas
CBM	coalbed methane
CCC	Committee on Climate Change (UK)
CCS	carbon capture and storage
CCGT	combined cycle gas turbine
CMM	coalmine methane
CNG	compressed natural gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation (Australia)
CH_4	methane
CO_2	carbon dioxide
CO_2-e	CO_2-equivalent
CSG	coalseam gas
CSM	coalseam methane
DECC	Department of Energy and Climate Change (UK)
DMS	dimethyl sulphide
EC	European Commission
EDF	Environmental Defence Fund (USA)
EEA	European Environment Agency (Denmark)
EECCA	Eastern Europe, Caucasus and Central Asia (countries)
EIA	Energy Information Administration (USA)
EU	European Union
FGD	flue gas desulphurisation
FSU	former Soviet Union (countries)
GAINS	Greenhouse Gas and Air Pollution Interactions and Synergies model
GEAS	Global Environmental Alert Service
GHG(s)	greenhouse gas(es)
GMI	Global Methane Initiative (USA)
GWP	global warming potential
HRSG	heat recovery steam generator
HFCs	hydrofluorocarbons
IAM	integrated assessment model
IEA	International Energy Agency (France)
IGCC	integrated gasification combined cycle
IIASA	International Institute for Applied Systems Analysis (Austria)
IPCC	Intergovernmental Panel on Climate Change (Switzerland)
ISAM	Integrated Science Assessment Model
JOGMEC	Japan Oil, Gas and Metals National Corporation (Japan)
LHV	lower heating value
LNG	liquid/liquefied natural gas

M2M	Methane to Market Partnership
MB	mass balance flux
MLR	Ministry of Land and Resources (China)
Mm^3	million cubic meters
N_2O	nitrous oxide
NCAR	National Center for Atmospheric Research (USA)
NERC	North American Electric Reliability Corporation (USA)
NETL	National Energy Technology Laboratory (USA)
NGL	natural gas liquids
NPC	National Petroleum Council (USA)
NRDC	Natural Resources Defence Council (USA)
NSPS	New Source Performance Standards (USA)
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development (France)
PFCs	perfluorocarbons
PM	particulate matter
ppb	parts per billion
ppm	parts per million
RAINS	Regional Air Pollution Information and Simulation (Austria)
RF	regional flux
SF6	sulphur hexafluoride
SO_2	sulphur dioxide
SRU	German Advisory Council on the Environment (Germany)
Tcf	trillion cubic feet
Tm^3	trillion cubic meters
UNEP	United Nations Environment Programme (Switzerland)
UNFCCC	United Nations framework convention on climate change (Germany)
US DOE	US Department of Energy (USA)
US EPA	US Environment Protection Agency (USA)
VAM	ventilation air methane
VOC	volatile organic compounds
WCA	World Coal Association (UK)
WEC	World Energy Council (UK)

Contents

List of Figures

List of Tables

1 Introduction

Coal is the most widely used primary energy source in power generation, with a 36% share of globally generated power in 2014. Its significance varies by region. In countries with large resources/reserves such as Australia, China, Poland and South Africa, the share of coal power generation is more than 60%. In import-dependent regions such as Europe and Japan, the share is lower, but with 15% and 25%, respectively, coal has a significant role to play in power generation in these regions too. Switching from coal, to gas, or substitution of high-carbon intensive fuels with fossil fuels with lower carbon intensity, on an energy content basis, is considered one of the principal methods of reducing greenhouse gas emissions (GHGs) from the energy sector. However, several studies published in recent years question the implications for climate change of large scale switching from coal to gas for electricity generation. It is well known that natural gas combustion produces about half the greenhouse gases compared to coal. However, recent studies have shown that in order to evaluate the performance of gas as a cleaner alternative to coal, fugitive methane (CH_4) emissions associated with gas extraction and processing must be explored and considered.

Methane is an important greenhouse gas, as it is approximately 20–25 times more potent than carbon dioxide (CO_2) (over 100 years). Some sources estimate an even higher potency of 34. Nevertheless, it was considered, in the past, that as the amount of methane emitted due to combustion is a fraction of the CO_2 emitted and, as methane also has a shorter residence time in the atmosphere, its impacts were less detrimental compared to CO_2. Today, this perception no longer holds.

After CO_2, methane is the second largest contributor to GHG emissions. Major economic sectors that produce methane emissions are agricultural processes including livestock management and rice cultivation, and natural gas systems. Other major contributors include landfills, petroleum production, and coal mining. According to the US EPA (2014a), in 2012, in the USA, methane emissions accounted for 9% of all USA GHG emissions. However, the US EPA uses a global warming potential (GWP) of 21 (over 100 years) for methane in accordance with the International Panel on Climate Change (IPCC) national inventory reporting guidelines. Higher GWPs have been published in the literature, including in the third (2001), fourth (2007), and fifth (2013) assessment reports from the IPCC. For details on those and past IPCC assessment reports, *see* https://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml#1. Using higher factors would increase the contribution of methane to total greenhouse gases relative to CO_2.

Methane is emitted at several stages during the production, supply and use of gas. Fugitive emissions of methane are a significant source during the production phase. This includes methane released from exploration drilling, production testing and well completion, and gas production activities including processing, venting and flaring. Well completion is the culmination of activities and methods used to prepare a well for production following drilling, including installation of equipment for production from a gas well.

Recovery of methane from coal seams is often referred to as coalbed methane (CBM) or coalseam gas (CSG) extraction. This includes the recovery of methane prior to mining taking place. In some coal mines, CBM is recovered mainly to drain the seam of as much methane as possible before mining takes place. This reduces the risk of explosion and mitigates methane emissions to the atmosphere once the process of extracting the coal begins. CBM can also be recovered for use in energy production, regardless of whether the coal in the mine is extracted or not. Methane recovered from working mines is usually referred to as coalmine methane (CMM). Drivers for CMM recovery include mine safety and mitigation of significant volumes of methane emissions resulting from coal mining activities. CMM can also be used for energy production.

There are four main categories of unconventional natural gas: shale gas, coalbed methane, gas from tight sandstones (tight gas) and the least well-known methane hydrates. In shale gas exploration, hydraulic fracturing, or 'fracking', is a technique used to boost the flow of gas from a new well. Large quantities of water and sand, together with proprietary chemicals, are pumped into a newly drilled well at high pressure, to create fractures in the underground rock layers such as shale deposits. Gas can then migrate through the fractures. Recently, several scientists re-evaluated the importance of methane leaks during the production and processing of conventional natural gas as well as unconventional natural gas.

Methane gas leaks in gas exploration and production can be from a variety of sources, including cracked well casings, seepage, deliberate venting during normal operations and malfunctioning valves. Most leaks are considered to be due to equipment. These leaks are referred to as 'super-emitters'. The implication is that these represent a small fraction of all wells and therefore significant reductions may be achieved with technological developments and best practice applications in those areas. On the other hand, finding seepage, given that pipelines and distribution pipes cover millions of kilometres and millions of active as well as abandoned wells throughout the world is difficult. However, despite the difficulties, technologies and methods to find these sources must be developed rapidly, at a reasonable cost, and used quickly to control these emissions.

Computer simulations and modelling tools show that substitution of coal by gas would be less beneficial than hitherto assumed, mainly due to methane leakage effects and their impact on the climate. The recent developments in technology and economics of gas exploitation have raised the prospects for substantially increasing global natural gas reserves and production. This is expected to have implications for substitution of natural gas for coal in power generation on a large scale to reduce environmental and global climate impacts of fossil power generation. However, some studies show that coal could have a lower climate impact than gas in the short- to medium-term especially when using the most efficient and advanced technologies for coal-fired power generation.

There are currently two schools of thought on the amounts and impacts of methane emissions from natural gas systems. One considers that methane leakage/emissions have been less than the estimates put forth in 2013 by the other school. The former therefore consider that this keeps natural/shale gas at an advantage compared to coal's greenhouse gas emissions tally, whilst the latter demand further investigation on the impacts of widespread natural and shale gas exploration, extraction, distribution and use in power generation.

There are also concerns about the impact of hydraulic fracturing (fracking) for gas production on groundwater flows, supply and purity, as well as surface water impacts, habitat fragmentation, health and sociological issues. The extent of water use and the risk of contamination are key issues for any unconventional gas development and the issue has generated considerable public concern.

Although this review will discuss the climate implications of large-scale coal-to-gas substitution in power generation, the focus is on methane emissions associated with both fuels during their life cycle, and their role in potential climate change.

2 Methane emissions and coal

Methane can come from a variety of sources including a large contribution from the energy and power industries. Natural sources of methane include wetlands, lakes, oceans, and fires. According to the US EPA 2010a, these natural sources account for 37% of all methane emissions. According to Yusuf and others (2012), 24% of all man-made methane emissions are due to fugitive emissions from fossil fuel infrastructure (18% from oil and gas plus 6% from coal mining) (*see* Figure 1). The increasing trend in emissions shown in Figure 1 is expected to continue. The potential of CO_2 equivalent emission reduction gained from 1 billion m^3 (Bm^3) methane utilisation is 3.6 Mt/y (Oprisan, 2011).

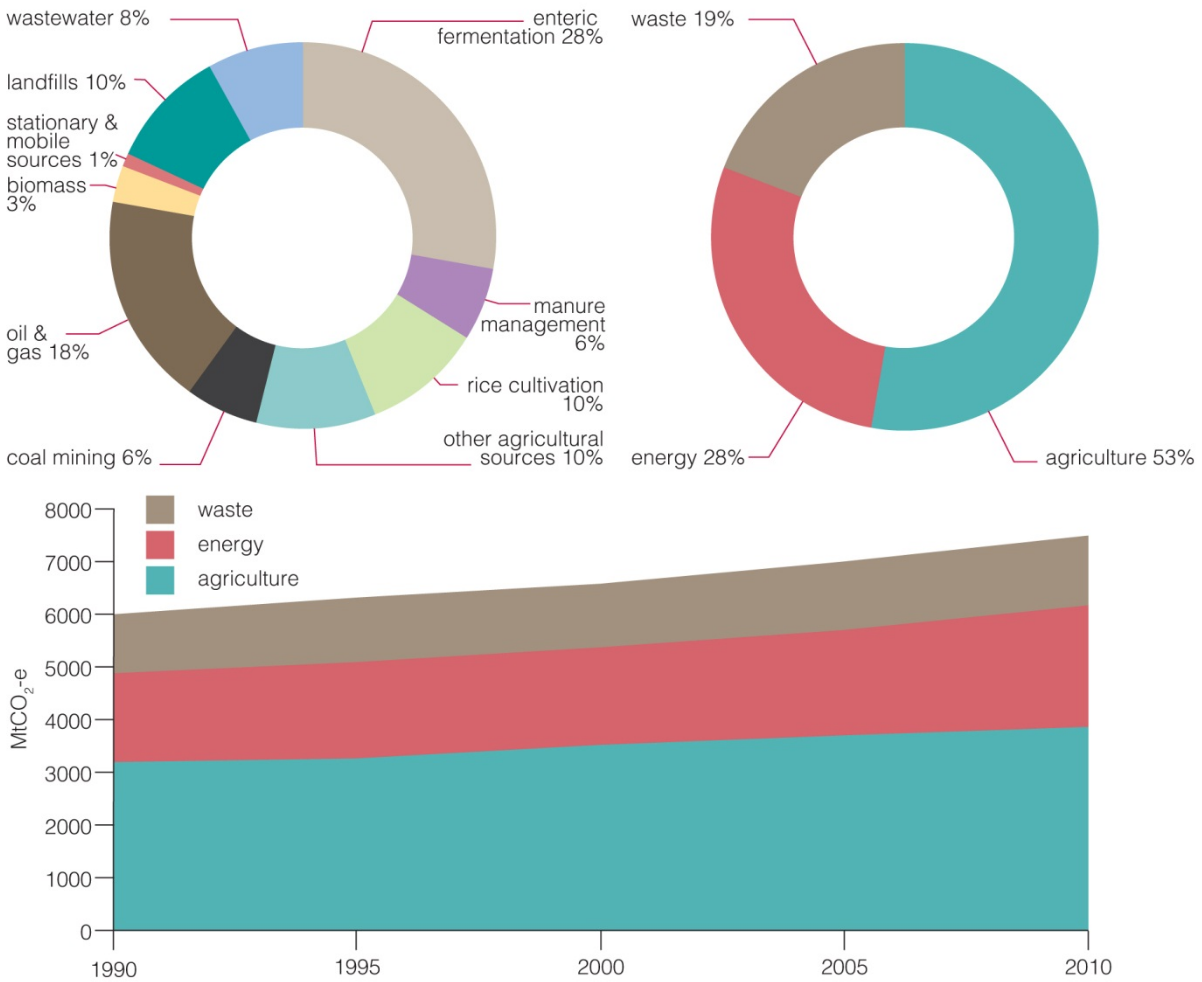


Figure 1 Methane emissions sources (Yusuf and others, 2012)

There are, broadly, two approaches to measuring fugitive emissions: bottom up and top down (*see* Figure 2). Bottom up methods examine methane emissions at the source, whether that is at the gas well, along the pipeline transporting the fuel or at the final destination providing a snapshot of emissions at a particular point in the process. However, since, in general, data are measured or gathered at a particular section, only a partial picture of the process emissions is obtained. This may result in missing a leak in a pipeline somewhere along the line, making the estimates relatively low. On the other hand, measuring emissions from a series of wells that are particularly leaky, would result in relatively high estimates. Top down approaches avoid the discrepancy by measuring the amount of methane in the atmosphere from a height sufficient to capture emissions in a whole area. Although it is difficult to trace the emissions back to a particular source with this approach, top down methods allow the estimation of the amount of methane emitted in an area without identifying where it came from. As there are other sources unrelated to natural gas extraction that also emit methane such as wetlands or landfills, top down approaches tend to result in higher estimates than bottom up approaches. They provide a more complete and unbiased assessment of emissions sources, and can detect emissions over broad areas (Ekstrom, 2014).

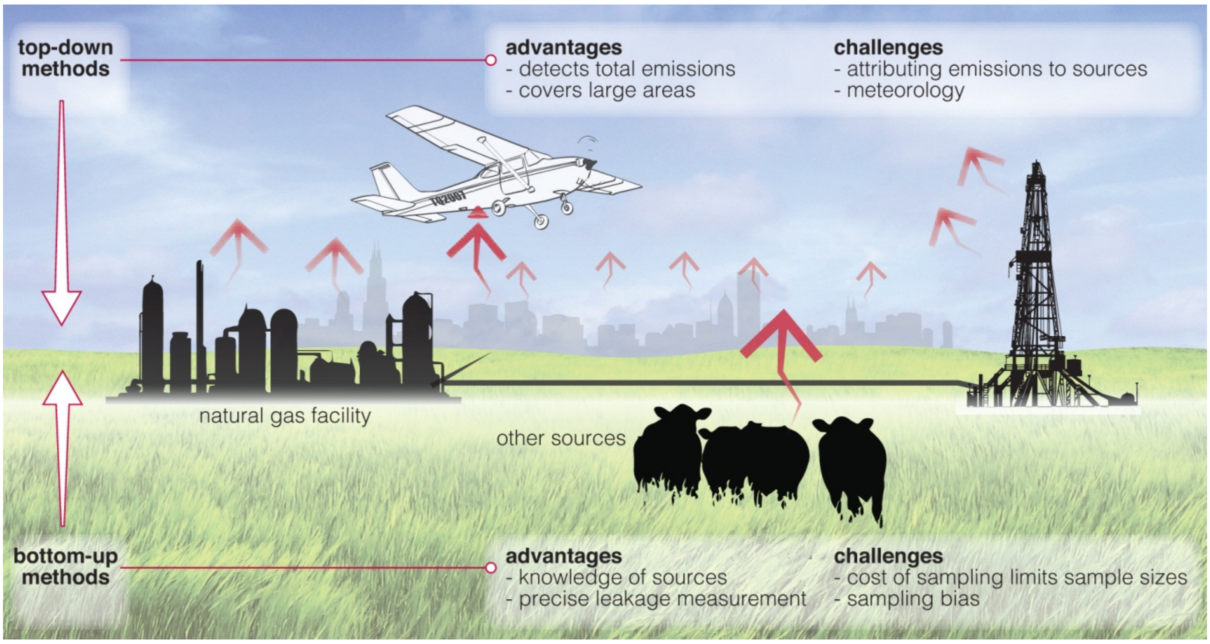


Figure 2 Fugitive methane emissions measuring approaches (Ekstrom, 2014)

In 2014, the US EPA published a document analysing potential upstream methane emissions changes in coal mining as well as natural gas systems in the USA (US EPA, 2014b). The term 'upstream emissions' in the analysis referred to 'vented, fugitive and flared emissions associated with fuel production, processing, transmission, storage, and distribution of fuels prior to fuel combustion in electricity plants'. The focus was on upstream methane from the natural gas systems and coal mining sectors. In addition, the analysis included CO_2 resulting from flaring in natural gas production. The analysis did not assess other upstream GHG emissions changes, such as CO_2 emissions from the combustion of fuel used in natural gas and coal production activities or other non-combustion CO_2 emissions from natural gas systems, such as vented CO_2 and CO_2 emitted from acid-gas removal processes. The purpose of the US EPA analysis was to study the regulatory impact for the USA proposed carbon pollution guidelines for existing power plants and emission standards for modified and reconstructed power plants. Implementing the proposed guidelines is expected to reduce emissions of CO_2 and ancillary emissions of SO_2, NO_2 and $PM_{2.5}$. However, the US EPA study was unable to quantify or monetise all of the climate benefits and health and environmental co-benefits associated with the proposed emission guidelines, including reducing exposure to SO_2, NOx, and hazardous air pollutants, such as mercury and hydrogen chloride, as well as ecosystem effects and visibility impairment (US EPA, 2014b).

2.1 Coalseam/coalbed and coalmine methane

Coalseam gas (CSG) refers to methane that is trapped within pores and fractures in underground coal deposits. Due to high underground pressures, the gas is usually found in a semi-liquid state, lining the inside surfaces of the coal matrix (Department of Climate Change and Energy Efficiency, 2012). CSG is chemically similar to conventional natural gas. Methane is the main component of both. Other common names for CSG include coalbed methane (CBM) (the most widely used), coalseam methane (CSM) and coalbed gas (CBG). Methane gas can also be released from coal deposits by coal mining activity, which is known as coalmine methane (CMM) and/or coalmine waste gas. Methane has been traditionally extracted from coals to reduce mining hazards, but the gas was vented to the atmosphere with large fans in the mines. In the USA, some methane was tapped from coal by vertical wells early in the last century and the gas was used locally.

CBM is extracted through wells drilled directly into coal seams (*see* Figure 3). This became possible on a commercial scale relatively recently, especially since the 1990s, due to advances in drilling technology. Following extraction, the CBM/gas, can be provided to residential and industrial customers through natural gas pipelines or exported via liquefied natural gas (LNG) terminals. Production of CBM has become an important industry that can provide an abundant, clean-burning fuel in an age when there is concern about pollution and fuel shortages. The process may be applicable wherever coal is found. Australia, Canada, China, France, Germany, Poland, Russia, Spain, the UK and Zimbabwe and are a few of the countries that have undertaken projects after the initial success in the USA. Over 60 countries have substantial coal reserves, and therefore have the potential of recovering the methane. In countries where coal is one of the few natural energy resources CBM can be a key to reducing air pollutant emissions and supplying much needed energy to industry.

CBM is an emerging industry, which has been developing since the 1990s. Initial process improvements were rapid with innovations improving production, economics, reservoir management, and drilling (Halliburton Company, 2008).

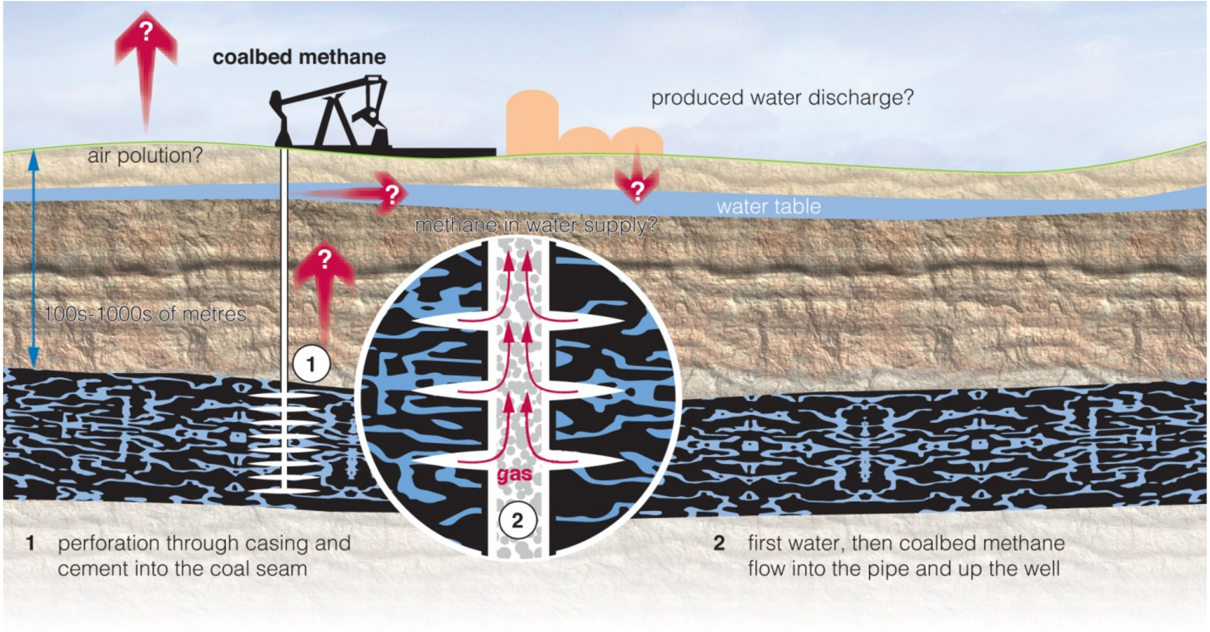


Figure 3 Coalbed methane production techniques and possible environmental hazards (Halliburton Company, 2008; IEA, 2012)

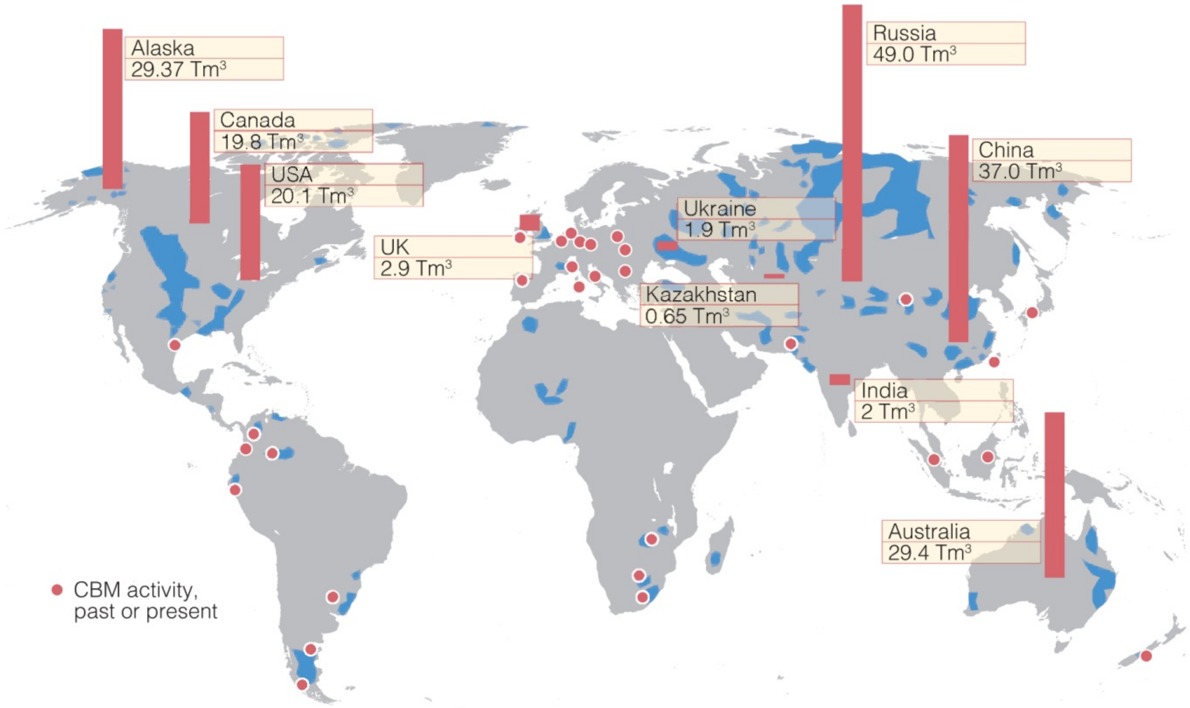
CBM has the following attributes (Halliburton Company, 2008):

- production of the methane reduces further mining hazards;
- coal beds too deep to mine economically may eventually be used as a source of methane as technology advances;
- methane is a relatively clean burning fossil fuel;
- drilling for the methane is considered a benign operation with low risk of blowout or spillage because air is often used instead of drilling muds; and
- methane emissions to the atmosphere from mines are reduced.

The environmental aspect of methane emissions into the atmosphere from mines is an international problem. According to Halliburton Company (2008), emissions from coal mines were estimated to account for as much as 10% of methane emissions from all sources worldwide. At the time, ~70% of the mine emissions may have come from Russia, China, the USA and Poland.

Emissions from CBM occur at several stages during the production, supply and use of CBM. Fugitive emissions of methane are a significant source during the production phase. This includes methane released from exploration drilling, production testing and well completion, and gas production activities including processing, venting and flaring. Methane is a potent greenhouse gas, with a global warming potential (GWP) more than 20 times that of carbon dioxide over 100 years. In Australia, in 2008-09, fugitive emissions from the natural gas sector, including CBM as well as conventional gas, were estimated to be 9.3 Mt of CO_2-equivalent (CO_2-e), or around 1.6% of the national inventory total. Other sources include fugitive emissions during transportation and supply (for example leakage from pipelines), emissions from fossil fuel use during the development and operation of CBM facilities, and emissions from end-use combustion of CBM (for example for heating or electricity generation). According to

Australian National Greenhouse Accounts (2012), there have been a number of recent developments relevant to the estimation of CBM fugitive emissions. CBM activity and reserves are shown in Figure 4 (Al-Jubori and others, 2009). CBM from prospect to pipeline was the subject of a report edited by Thakur and others (2014). In 2014, Dodson reported that the NSW government announced plans to pause, reset and restart CBM exploration in the Australian State. There is a current freeze on new CBM exploration applications, which will continue, according to Dodson (2014), until a new 'gas plan' framework is developed.



CBM reserves and activity – major reserves are found in Russia, the USA (Alaska alone has an estimated 29.37 Tm³) China, Australia, Canada, the UK, India, Ukraine, Kazakhstan. Of the 69 countries with the majority of coal reserves, 61% have recorded some form of CBM activity / investigation, testing or production.

Figure 4 Coalbed methane (CBM) reserves and activity (Al-Jubori and others, 2009)

Field measurements of fugitive methane emissions from equipment and well casings in Australian CSG production facilities was the subject of a report by Day and others (2014). The measured emissions, at 43 CSG wells, six in New South Wales (NSW) and 37 in Queensland, were made by downwind traverses of well pads using a vehicle fitted with a methane analyser to determine total emissions from each pad. In addition, a series of measurements were made on each pad to locate sources and quantify emission rates. Day and others (2014) found that of the 43 wells examined, only three showed no emissions. These were two plugged and abandoned wells and one suspended well that had been disconnected from the gas gathering system. The remainder had some level of emission but, in general, the emission rates were low, especially when compared to the volume of gas produced from the wells. The principal methane emission sources were found to be venting and operation of gas-powered pneumatic devices, equipment leaks and exhaust from gas-fuelled engines used to power water pumps. The emission rates measured at the facilities are reported as much lower than those that have been reported for USA unconventional gas production (Day and others, 2014).

The results obtained in the Day and others (2014) study represent the first quantitative measurements of fugitive emissions from the Australian CSG industry. However, the authors consider that a number of areas require further investigation. Firstly, the number of wells examined represents a very small proportion of the total number of wells in operation. In addition, many more wells are likely to be drilled over the next few years. Consequently, the small sample examined during the study may not be truly representative of the total well population. Day and others (2014) also note that emissions may vary over time, for instance due to repair and maintenance activities. A larger sample size would be required and measurements would need to be made, over an extended period, to determine temporal variation in order to fully characterise emissions. Furthermore, many other potential emission points throughout the gas production and distribution chain were not examined in the study. These include well completion activities, gas compression plants, water treatment facilities, pipelines and downstream operations including LNG facilities. Day and others (2014) conclude that reliable measurements on Australian facilities are yet to be made and the uncertainty associated with some of these estimates remains high.

There are also concerns about the impact of CBM production on groundwater flows and the supply and purity of water in aquifers adjacent to the coal seams being exploited. The extent to which this can occur is location specific and depends on several factors. The most important factors include the overall volume of water initially in the coalbed and the hydrogeology of the basin. Also, the density of the CBM wells, the rate of water pumping by the operator, the connectivity of the coalbed and aquifer to surrounding water sources and, therefore, the rate of recharge of the aquifer, and the length of time over which pumping takes place (IEA, 2012).

In most basins, water is a necessary by-product of CBM production. According to Al-Jubori and others (2009), managing produced water is a costly aspect of CBM development in some areas. The quality of the water depends largely on the geology of the coal formation. Produced water is low in dissolved oxygen, so it must be aerated before it can be discharged into rivers. Irrigation with produced water may be problematic unless treated/managed due to dissolved solids, which may cause soil damage. Al-Jubori and others (2009) consider that water from CBM production with high solids content must be injected into deeper saline aquifers away from freshwater drinking sources.

Methane recovered from working mines is usually referred to as coalmine methane (CMM). Drivers for CMM recovery include mine safety and mitigation of significant volumes of methane emissions resulting from coal mining activities. CMM can also be used for energy production. Methane emissions in working mines arise at two key stages (WCA, 2014):

- methane is released as a direct result of the physical process of coal extraction. In many modern underground mines, the coal is extracted through longwall mining. Longwall mining, as with other sub-surface techniques, releases methane previously trapped within the coal seam into the air supply of the mine as layers of the coal face are removed, thus creating a potential safety hazard, and/or;
- methane emissions may arise from the collapse of the surrounding rock strata after a section of the coal seam has been mined and the artificial roof and wall supports are removed as mining progresses

to another section. The debris, resulting from the collapse is known as gob or culm, and also releases methane or 'gob gas' into the mine.

According to the WCA (2014), the potential for future mining operations is largely dependent on the accessibility of the coal seams. Coal found at extreme depths is often not considered feasible for extraction because of practical, safety and economic considerations. In such cases, methane recovery activity is purely for the purpose of energy generation and does not have safety or climate change benefits (as the methane would not have been emitted).

In 2004, 14 countries came together to launch the Methane to Markets (M2M) Partnership. M2M was re-launched as the Global Methane Initiative (GMI) in 2010. The aim of the body is to reduce emissions of methane, by promoting the development of projects that recover and use methane as a clean energy source. GMI is an international public-private partnership currently working with government agencies around the world to facilitate project development in four key methane-producing sectors: agricultural operations, *coal mines,* landfills, and oil and *gas systems*. The aims of the collaboration include enhancing economic growth and energy security, improving air quality and industrial safety, and reducing overall GHG emissions.

Today the GMI includes 37 partner countries and the European Commission (EC), representing about 70% of the world's anthropogenic methane emissions. The GMI also includes a project network of >1000 members from sectors such as international finance, development, the policy arena and non-profit institutions with a common goal of promoting methane recovery and use projects around the world (GMI, 2010).

In December 2010, the GMI published a report on reducing methane emissions in the coal mine sector. The study scoped out the opportunities across the world for CMM recovery projects, profiling a total of 37 countries, most of which are actively producing coal or have significant coal reserves. Each country profile included an overview of its coal industry; and characterised and quantified its CMM emissions. Brief descriptions of individual coal mines were also provided where possible. The countries included in the review were Argentina, Australia, Botswana, Brazil, Bulgaria, Canada, China, Colombia, Czech Republic, Ecuador, Finland, France, Georgia, Germany, Hungary, India, Indonesia, Italy, Japan, Kazakhstan, Mexico, Mongolia, New Zealand, Nigeria, Pakistan, Philippines, Poland, Republic of Korea, Romania, Russia, South Africa, Spain, Turkey, Ukraine, UK, USA and Vietnam.

According to the US EPA (2010b), total methane emissions from coal mining are estimated in Table 1 for 1990, 1995, 2000 and 2005. China, which has the world's highest coal production, also emitted the greatest amount of CMM, estimated at more than 136 million tonnes of CO_2 equivalent ($MtCO_2$-e) per year in 2005. However, 2011 estimates of CMM emissions indicate that the total emissions in 2010 were ~584 $MtCO_2$-e. Other large CMM emitters are shown in Figure 5.

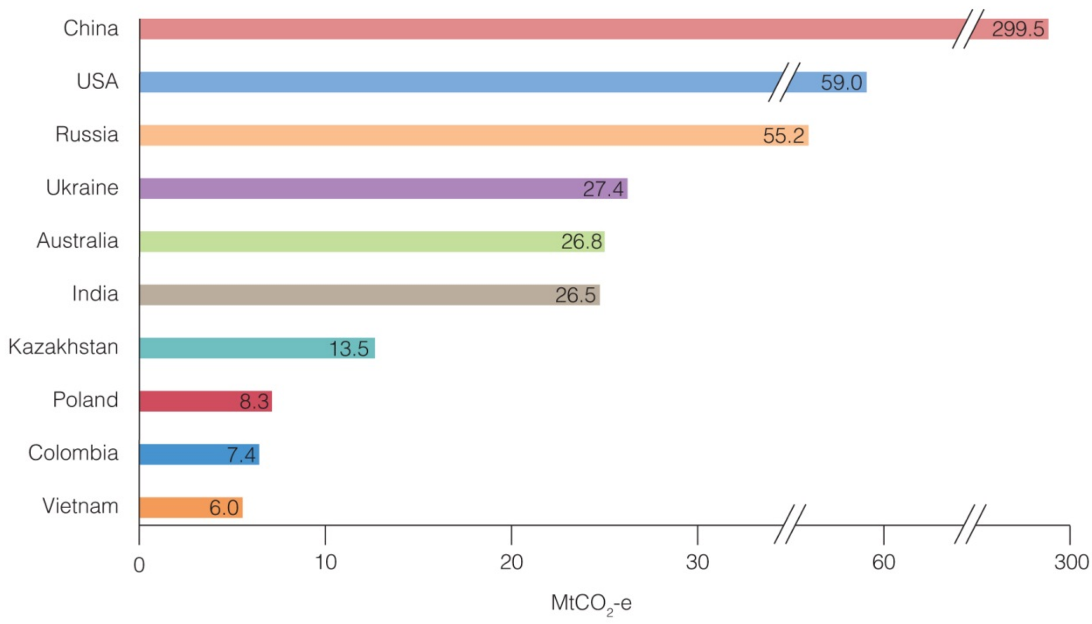


Figure 5 Estimated top 10 GMI countries CMM emissions, 2010 (GMI, 2011)

Methane released from coal mining activities in underground and surface mines is of concern as methane is explosive in nature and poses a safety hazard to miners. In 2005, CMM constituted 6% of the global anthropogenic methane emissions. According to US EPA (2010b), if recovered and utilised, CMM not only provides valuable clean fuel and environmental benefits, but also improves mine safety and productivity.

Table 1 Methane Emissions from Coal Mining ($MtCO_2$-e) (US EPA; GMI, 2010; US EPA, 2006a)

Country	1990	1995	2000	2005*	Rank as of 2005
Argentina	0.2	0.25	0.25	0.23	29
Australia	15.8	17.5	19.6	21.8	5
Botswana	n/a	n/a	n/a	n/a	n/a
Brazil	1.2	1.1	1.3	1.2	19
Bulgaria	1.6	1.4	1.2	1.3	18
Canada	1.9	1.7	1.0	0.9	23 (tie)
China	126.1	149.1	117.6	135.7	1
Colombia	1.9	2.0	3.0	3.4	13
Czech Republic	7.6	5.8	5.0	4.8	12
Ecuador	0	0	0	0	34 (tie)
Finland	0.01	0.01	0.01	0	34 (tie)
France	4.3	4.4	2.6	2.6	15
Germany	25.8	17.6	10.2	8.4	8
Georgia	0.007	0.001	0	0	34 (tie)
Hungary	1.1	0.7	0.6	0.49	27
India	10.9	13.7	15.8	19.5	6
Indonesia	0.3	0.4	0.4	0.5	26
Italy	0.1	0.06	0.07	0.07	31
Japan	2.8	1.3	0.8	0.8	25
Kazakhstan	24.9	17.2	10.0	6.7	11
Mexico	1.5	1.8	2.2	2.5	16
Mongolia	0.2	0.1	0.07	0.05	32
New Zealand	0.3	0.3	0.3	0.4	28
Nigeria	1.8	2.9	1.2	0.02	33
Pakistan	0.9	1.0	1.0	1.1	22
Philippines	0.2	0.2	0.2	0.2	30
Poland	16.8	15.6	11.9	11.3	7
Republic of Korea	4.8	1.6	1.2	0.9	23 (tie)
Romania	3.7	3.9	2.7	2.8	14
Russia	60.9	36.8	29	26.2	4
South Africa	6.7	6.7	7.1	7.4	9
Spain	1.8	1.4	1.2	1.2	20
Turkey	1.6	1.6	1.7	1.8	17
Ukraine	55.3	30.1	28.3	26.3	3
UK	18.3	12.6	7.0	6.7	10
USA	81.9	65.8	56.2	55.3	2
Vietnam	0.5	0.8	1.0	1.2	21
Total	**482**	**416**	**340**	**329**	

* 2005 emissions: extrapolated based on changes in coal production from 1995-2000

The quality of CMM varies depending on the source of emission. CMM drained from underground mine workings through ventilation systems to avoid concentration build-up is diluted. Referred to as ventilation air methane (VAM), it however accounts for the largest source of CMM emissions globally. In some instances, it is necessary to supplement the ventilation with a degasification system consisting of a network of boreholes and gas pipelines that may be used to capture methane before, during, and after mining activities to keep the methane concentration within safe limits. 'Abandoned' or closed mines may also continue to emit methane, typically of low to medium quality, from ventilation pipes or boreholes.

According to the US EPA (2010b), technologies are available to recover and use methane from active or abandoned coal mines, including a technology which has been demonstrated to recover the energy content of dilute, typically <1%, methane emissions from mine ventilation shafts. Specific uses for recovered CMM depend on the gas quality, especially the concentration of methane and the presence of other contaminants in the drained gas. CMM is typically used worldwide for power generation, district heating, boiler fuel, or town gas, or it is sold to natural gas pipeline systems. CMM can also be used in many other ways, including coal drying, as a heat source for mine ventilation air or supplemental fuel for boilers, for vehicle fuel as compressed natural gas (CNG) or liquefied natural gas (LNG), as manufacturing feedstock, or as a fuel source for fuel cells and internal combustion engines (*see* Table 2).

The US EPA (2010b) consider that although there are significant benefits and scope for CMM recovery, developing CMM projects face several challenges. These include access to appropriate technology to assess resources, effectively installing drainage systems, and selecting appropriate end use technologies. Market barriers include appropriate price signals and adequate infrastructure to transport the gas. Finally, regulatory and policy issues such as clear establishment of property rights to the gas and access to capital or financing also impede CMM project development (GMI, 2010).

Worldwide CMM recovery and utilisation activities currently in operation or under development, in 2014, are shown in Table 2. In total, there are currently 355 CMM projects in operation or under development throughout the world. In 2010, ongoing CMM projects could be found in 16 of the 37 countries profiled in the US EPA (2010b) report. Total emissions avoided through these projects were calculated as 73.6 $MtCO_2$-e. China, Australia, Czech Republic, Germany, Poland, UK and the USA in particular hosted numerous projects at active mines, whilst Germany, Ukraine, UK and the USA hosted many projects at abandoned mines. Countries in early CMM development stages included: New Zealand, India and South Africa. These three countries conducted methane drainage in addition to ventilation at active coal mines. Italy also carried out a feasibility assessment of drainage at an abandoned mine. All these countries have strong potential to recover and utilise drained gas in the future (GMI, 2010).

Table 2 Coalmine methane (CMM) recovery and utilisation projects* (2014) (GMI International CoalMine Methane Projects database, 2014) **http://projects.erg.com/cmm/projects/ProjectFindResultsAll.aspx?mode=new**

Country	Projects at active mines	Projects at abandoned mines	Project end uses
Australia	20	5	Boiler fuel, flaring, power generation, pipeline injection, ventilation air methane (VAM) as auxiliary fuel for combustion air
Belgium	–	–	2 projects currently under development
China	91	0	1 unknown project Boiler fuel, power generation, town gas, industrial use, VAM as primary fuel for power generation, VAM destruction, combined head and power (CHP), vehicle fuel, flaring
Czech Republic	6	5	9 unknown projects CHP, pipeline injection
France	0	3	Industrial use, pipeline injection
Germany	9	37	2 unknown projects Power generation, CHP, flaring
Japan	0	2	Power generation, industrial use
Kazakhstan	1	0	Boiler fuel
Mexico	4	1	Boiler fuel, power generation, flaring
Poland	21	1	Flaring, coal drying, CHP, industrial use, power generation, boiler fuel
Romania	1	1	Boiler fuel, CHP
Russia	12	0	Boiler fuel, power generation, flaring
Slovakia	1	0	2 unknown projects CHP
South Africa	1	0	Flaring
Ukraine	27	2	2 unknown projects Boiler fuel, CHP, power generation, heating or cooling, flaring, industrial use, pipeline injection
UK	24	23	Heating or cooling, power generation, boiler fuel, flaring, VAM destruction, industrial use
USA	19	26	Pipeline injection, VAM destruction, flaring, heating or cooling, power generation, coal drying

2.2 Power generation

Carbon dioxide, methane and nitrous oxide are produced during coal combustion. Nearly 99% of the fuel carbon in coal is converted to CO_2 during the combustion process. The conversion is relatively independent of the firing configuration. Methane emissions vary with the type of coal being fired and firing configuration. However, the emissions are highest during periods of incomplete combustion, such as start-up or shut-down cycles. Typically, conditions that favour the formation of methane are similar to those that favour N_2O emission formation. The rate of methane emission is also dependent on the temperature in the boilers. In large coal-fired combustion facilities and industrial applications, methane emission rates are low whilst in smaller applications such as residential use (that is, small stoves and open burning) rates are higher. The contribution of stationary coal combustion to total methane emissions is generally minor.

Power projects using methane from coal mines were the subject of a review from the IEA Clean Coal Centre. Sloss (2006) found that the capture and use of CMM is often technically challenging and many projects were not regarded as guaranteed investments. The simplest use of CMM is as a replacement for natural gas in gas pipelines. However, as the gas must be cleaned and pressurised, this necessitates investment in a gas processing system. The gas must also be delivered to the site of use, usually by pipeline. The USA has a market for CBM in natural gas pipeline injection and a supportive infrastructure. CBM and CMM gases are also fed into the natural gas system in Australia and France. In Asia, the majority of captured CMM is used locally as town gas, with the methane being piped only to the local community. Eastern European countries such as the Czech Republic also supply CMM through a local pipeline for residential use. Increasing global demand for energy means that significant investment is under way and expected to continue in order to extend the natural gas pipeline networks (*see* Nalbandian and Dong, 2013). This will enhance the opportunity for increased natural gas as well as CBM utilisation. Investment in natural gas pipelines in Africa is also under consideration.

According to Sloss (2006), medium quality CMM can be used as a combustion fuel in internal combustion engines and turbines. It can be cofired with natural gas, coal, waste coal and even in steel furnaces to provide an additional fuel source whilst, in most cases, reducing pollutant emissions. The most efficient of these systems are cogeneration systems that harness both the power and heat produced. The country with the most success in CMM-to-power projects in Europe is Germany, largely due to the financial incentive provided by government under the Renewables Energy Act. This guarantees a price for the sale of power produced from any CMM based project. The lack of such financial incentives in the rest of Europe means that such projects are not guaranteed. Several projects were established in the UK in the past but investment has been lacking in the recent past. In Eastern Europe, Russia and the Commonwealth of Independent States (CIS), including Azerbaijan, Armenia, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Moldova, Tajikistan, Turkmenistan, Uzbekistan and Ukraine, the major application of CMM is as mine boiler fuel with limited power generation and power use projects. It is also used as boiler fuel in China, largely at the coal mines themselves, with some being used for power generation. China received a significant amount of investment in CMM-to-power projects, largely through incentives such as those created under the Kyoto Protocol. The largest CMM to power project in the world (120 MWe) – funded by the World Bank, is at the Sihe Mine in Jincheng, Shanxi Province. The project utilises 180 Mm^3 of both CBM and CMM from the Sihe mine (USEPA, 2006b; Huang, 2008). The Sihe project reportedly avoids the release of 2.5 $MtCO_2$-e. Internal and external investment in Chinese projects continues. Furthermore, use of CMM is being considered for application in the chemical industry in China. China's coal basins and coalbed methane resources are shown in Figure 6 (GMI, 2010).

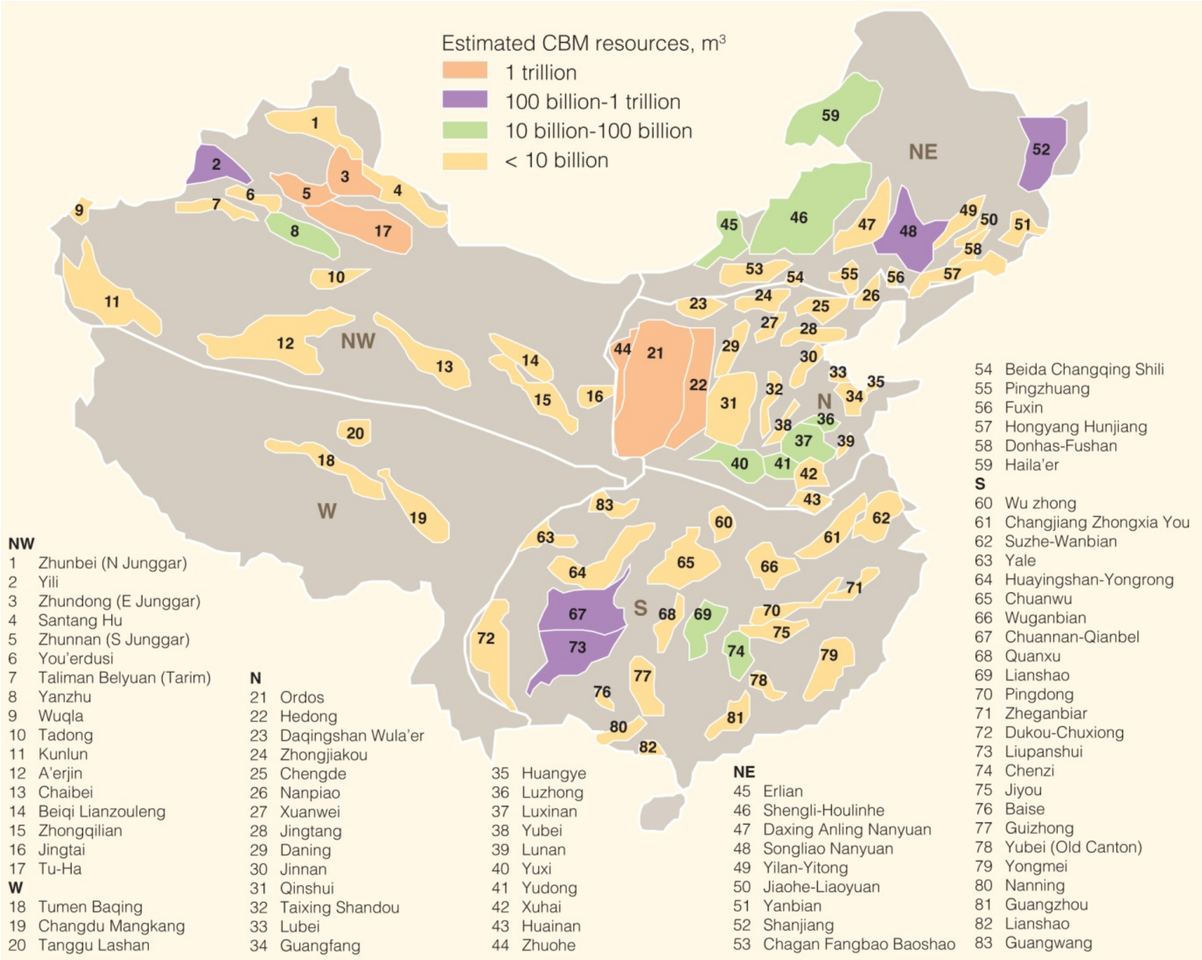


Figure 6 China's coal basins and coalbed methane (CBM) resources (GMI, 2010)

According to the US Department of Energy (US DOE) Energy Information Administration (EIA) (2014), most of China's CBM volumes are from basins in the North and Northeast, the Sichuan basin in the Southwest, and the Junggar and Tarim basins in the West. CBM production in 2012 was 441 Bcf (~12.5 Bm^3) from both surface wells and coal mines, and plans are to produce ~700 Bcf (~19.8 Bm^3) by the end of 2015. China also intends to increase the utilisation rates from <40% to >60% by the end of 2015, reducing the significant production waste. The EIA (2014) report highlights that although CBM production in China is increasing, developers face regulatory hurdles, technical challenges, a lack of pipeline infrastructure from coal mining areas to gas markets, and high development costs. In addition, at times, there are conflicting interests between governing bodies when dealing with mineral and land rights as the local governments hold rights to coal mines, whereas the central government has rights to natural gas and CBM. China's State Council issued a policy guideline in September 2013 encouraging investment in CBM exploration and development and more pipeline infrastructure through financial incentives and tax breaks to producers and reform of local price controls (EIA, 2014).

3 Methane emissions and gas

Conventional gas has been used to describe natural gas accumulations found in high permeability rock formations, typically sandstones or carbonates, where the hydrocarbons have migrated from finer grained source rocks like shales. These natural gas accumulations include some sort of trapping mechanism that prevents the gas from migrating further and results in a high concentration of gas within the reservoir.

There are four main categories of unconventional natural gas: natural gas found in shale source rocks (shale gas), coalbed methane (CBM), gas from tight, very low permeability sandstones (tight gas) and the least well-known methane hydrates. Tight gas refers to natural gas deposits that are particularly difficult to access from a geological viewpoint. The gas is contained in rocks with very low permeability in deep formations, typically deeper than 4500 m. Extraction requires a combination of processes such as hydraulic fracturing and horizontal drilling. Known reserves are found in countries with well-established gas industries, where significant detailed surveying has been conducted; including but not limited to the USA, UK, Russia and Canada. Methane hydrates are the least well-known unconventional gas. They are crystalline deposits of methane found in extensive seams under deep water in various parts of the world. Several countries have demonstrated interest in this potential form of energy, including Canada, China, Japan, Norway and the USA. In March 2013, Japan was the first country to extract gas from offshore methane hydrates, with the aim of commercial production starting by early 2019 (WEC, 2013). According to Sotolongo (2014), Japan and the USA have agreed to cooperate on methane-hydrate production onshore on the north slopes of Alaska, targeting test output by 2020. The joint research project between the US DOE National Energy Technology Laboratory (NETL) and Japan Oil, Gas and Metals National Corporation (JOGMEC) will span five years (from 2015). It will focus on extracting the natural gas from methane-hydrate formations on the North Slope of Alaska. Methane hydrates are not discussed further in this review.

While the gas, conventional/unconventional, is identical, the reservoirs are not. There are nearly 700 known shales worldwide in more than 150 basins. In 2013, the EIA published a report assessing 137 shale formations in 41 countries outside the USA (EIA, 2013). However, only a few dozen of shales have undergone *proper* assessment for production potentials; most of these are in North America. The potential volumes of shale gas are large and this is likely to reshape significantly the gas markets worldwide. In ~30% of the identified basins, the existing infrastructure could reduce capital expenditures related to exploitation of shale gas. However, even in these basins there is likely to be significant need for capital expenditures to process, store and distribute the gas through a pipeline system. The capital costs of developing that infrastructure will be considerable and may result in delaying new production from coming online or make the entire endeavour uneconomic. Although capital costs may be significant, shale formations may still be worth exploiting for both financial and strategic reasons (WEC, 2013). Since the late 1970s, interest has grown in finding ways to understand, quantify and develop unconventional gas resources. In the USA, a combination of rising natural gas prices, tax enhancements and technology advancements have enabled increased production of natural gas from unconventional accumulations. In 2013, the US DOE Energy Information Administration (EIA) projected that over the next several decades, while tight gas and coalbed methane more or less maintain their contribution to the natural gas supply in the USA, shale gas contribution will grow significantly (NETL, 2013).

There is considerable uncertainty over the amount of fugitive methane emitted over the lifetime of a natural gas well. However, in general, emissions from natural gas production are substantial and occur at every stage of the natural gas life cycle, from pre-production through production, processing, transmission, and distribution. The US EPA estimates that more than 6 Mt of fugitive methane leaked from natural gas systems in 2011. Measured as CO_2 equivalent over a 100-year time frame, that is more GHG emissions than those emitted by all USA iron and steel, cement, and aluminium manufacturing facilities combined (Bradbury and Obeiter, 2013).

Howarth and others (2012) summarised the then current state of knowledge of methane emissions from natural gas systems based on peer-reviewed literature. Howarth and others (2012) found that natural gas systems were the single largest source of anthropogenic methane emissions in the USA, representing almost 40% of the total flux according to estimates from the US EPA. The authors noted that through the summer of 2010, the US EPA used emission factors from a 1996 study to estimate the contribution of natural gas systems to the US GHG inventory. Increasing evidence over the previous 16 years has indicated these emission factors were probably too low, and in April 2011, the US EPA released updated factors. The estimates for natural gas systems in Figure 7 are based on updated emission factors. Emission factors are defined as the quantity of methane emitted from each emitting source and for each emitting event. Some emissions are known, such as the gas released for operating reasons or for maintenance, some can be evaluated, based on the characteristics of components and their emission factors. Other emission factors are difficult to measure such as those deriving from fugitive emissions.

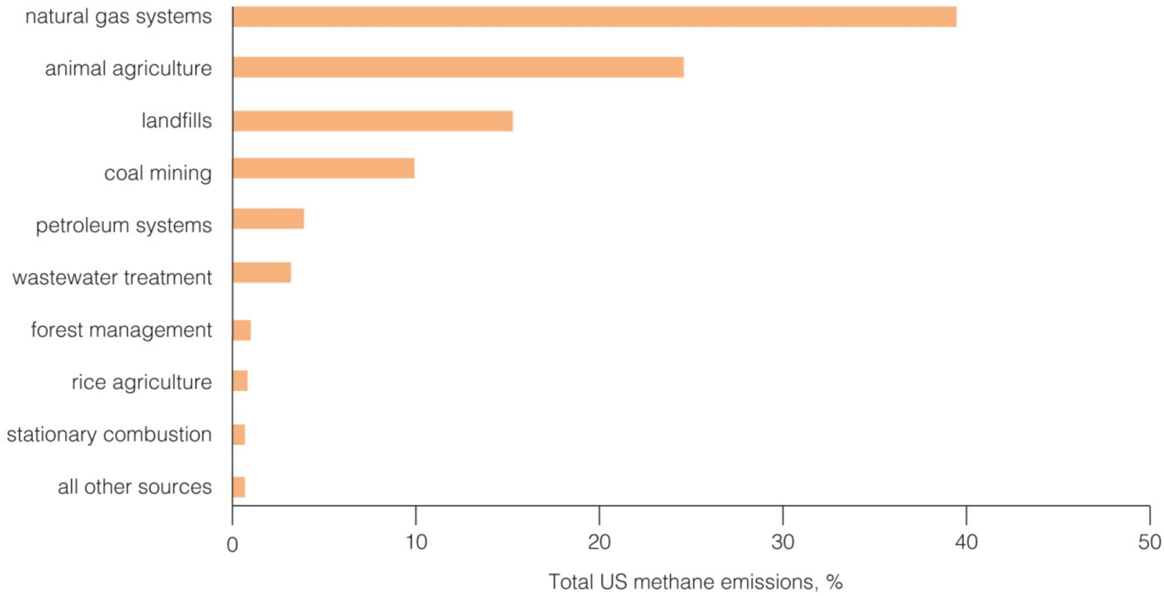


Figure 7 Human controlled sources of atmospheric methane from the USA for 2009, based on emission estimates from the US Environmental Protection Agency (EPA) in 2011 (Howarth and others, 2012)

Howarth and others (2012) noted that the use of the new methane emission factors resulted in a doubling in the estimate of methane emissions from the natural gas industry. In addition, the US EPA only increased emission factors for 'upstream' and 'midstream' portions of the natural gas industry (leaks and emissions at the well site and in processing gas). Factors for 'downstream' emissions (storage systems and transmission and distribution pipelines) are still based on the 1996 report, although the US EPA is also considering modifying these. The natural gas systems emissions in Figure 7 are based on an average emission of 2.6% of the methane produced from natural gas wells over their production lifetime, with 1.7% from upstream and midstream emissions (for the national mix of conventional and unconventional gas in 2009) and 0.9% from downstream emissions. Howarth and others (2011, 2012) note that these methane emission estimates from natural gas systems are based on limited data and remain uncertain. Estimates in the literature for downstream emissions of methane from natural gas systems range from 0.07% to 10% of the methane produced over the lifetime of a well.

In 2014, Howarth, using newly available data, some released by the US EPA and the IPCC and over a 20-year time period, to compare the warming potential of methane to CO_2, reached the conclusion that both shale gas and conventional natural gas have larger GHG emissions than coal or oil. Howarth (2014) considers that to be the case, for any possible use of natural gas and particularly for the primary uses of residential and commercial heating. The author reiterates that the 20-year time period is appropriate because of the urgent need to reduce methane emissions over the coming 15–35 years. He raises the question: is natural gas a bridge fuel? At best, Howarth (2014) considers using natural gas rather than coal to generate electricity might result in a very modest reduction in total GHGs, if those emissions can be kept below a range of 2.4–3.2%. However, that would require unprecedented investment in natural gas infrastructure and regulatory oversight.

There are currently many ongoing studies, which aim to provide more clarity on the extent of fugitive methane emissions from natural gas systems. Bradbury and Obeiter (2013) consider that a clearer picture will emerge when data from these studies are analysed in conjunction with industry data reported to the US EPA GHG reporting programme. However, according to Bradbury and Obeiter (2013) with hundreds of thousands of existing natural gas wells, thousands of miles of pipeline, and a growing interest in natural gas development throughout the world, a complete picture of the amount of methane being emitted through natural gas systems may not be obtained.

In 2014, McGarry and Flamm carried out a literature review, based on journal articles, government, NGO and industry reports, on USA methane leakage from natural gas systems. They found that 'nearly all of the researchers from industry, government and academia agree that more data are necessary from all stages of the natural gas life cycle (except during combustion) and that no one is quite sure how much methane is leaking. Few direct measurements have been made, but the few that have emerged recently from academic and government bodies suggest that official estimates may be substantially underestimating leakage in many cases. The US EPA has begun the next step in updating their inventory, which is to develop more accurate emission factors and to consider better measurement techniques'.

3.1 Exploration, extraction and production (natural gas and shale gas)

Natural gas essentially consists of methane, smaller amounts of other hydrocarbons including butane, ethane, propane, and other gases, plus molecular nitrogen (N_2), hydrogen sulphide (H_2S) and CO_2. Dry gas is natural gas, consisting primarily of methane that has little or no liquid hydrocarbons or condensate. Dry gas is produced from wells with very little condensate or liquid reserves. Wet gas is a mixture of gas that includes methane and higher hydrocarbons that become liquefied. Wet gas typically contains less methane and more ethane, and other hydrocarbons than dry gas. Hydrocarbons are chemicals that consist of carbon and hydrogen. Higher hydrocarbons such as ethane, propane, and butane are isomorphic to methane, meaning they have the same elemental composition but feature more complex bonds. Wet gas is more attractive to drill for because additional hydrocarbons are often marketable. Natural gas can include up to 20% ethane, butane, and propane. These gases can be useful in enhancing the efficiency of oil recovery in wells, as raw materials for petrochemical plants, and as energy sources. Wet gas is the primary source of ethane, which can be converted into ethylene, an important compound in many industrial production processes, through thermal processing and steaming (Glass, 2011). Table 3 shows the typical compositions (volume %) of natural gas as it reaches the wellhead and also after some constituents are removed and the gas is compressed for transport in a pipeline.

Liquefied natural gas (LNG) is practically all methane. Natural gas is found in rock formations (reservoirs) beneath the surface of the earth. Associated gas is natural gas that overlies and is in contact with crude oil in the reservoir. Non-associated gas is natural gas found in a reservoir, which contains no crude oil, and can be produced in patterns best suited to its own operational and market requirements. Once extracted, the natural gas is processed to remove other gases, water, rock particles, and impurities such as hydrogen sulphide. Some hydrocarbon gases, such as butane and propane, are captured, liquefied and marketed separately as natural gas liquids (NGLs). Once processed, the nearly all methane, cleaned natural gas, is distributed through a system of pipelines to its endpoint for residential, commercial, and industrial use (NETL, 2013).

Table 3 Composition of natural gas at various stages of production and distribution (NETL, 2013)

Component	Chemical Formula	Wellhead gas, %	Typical Pipeline, %	Liquefied natural gas, %
Methane	CH_4	70–90	88.90	94.7
Ethane	C_2H_6	0–0	5.34	4.8
Propane	C_3H_8	0–20	0.46	0.4
Butane	C_4H_{10}	0–20	0.05	0.06
Pentane	C_5H_{12}	<1	0.03	0.01
Hexane	C_6H_{14}	<1	0.02	0.01
Nitrogen	N_2	0–5	5.50	0.02
Carbon dioxide	CO_2	0–8	0.50	–
Hydrogen sulphide	H_2S	0–5	–	–
Rare gases	Ar, He, Ne, Xe	Trace	–	–
Average Btu/ft^3 (MJ/m^3)		1100–1300+ (~40.98–48.44+)	986 (~36.74)	1047 (~39.01)

In natural gas formations, a distinction is made between thermogenic and biogenic methane. Whereas thermogenic methane is formed from organic material at high temperatures and pressures in deep sedimentary horizons, biogenic methane forms close to the surface as a result of anaerobic microbial degradation, usually in wetlands. Thermogenic methane trapped in conventional and unconventional reservoirs is used for energy production. Natural gas in conventional reservoirs migrates, depending on porosity conditions, from the target rock along partings/fractures and pressure gradients into overlying reservoir rock (*see* Figure 8 (not to scale)).

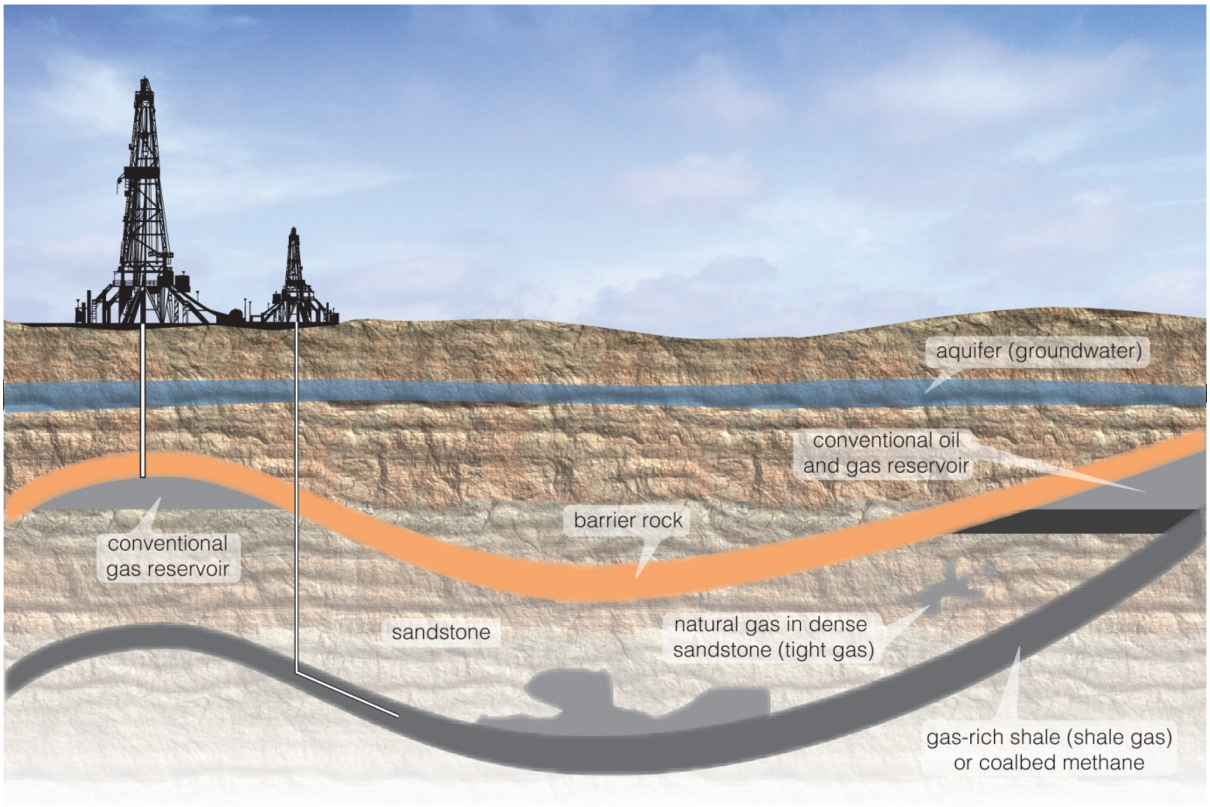


Figure 8 Oil deposits and conventional and unconventional gas reservoirs (not to scale) (SRU, 2013)

Where this formation is covered by a gas-tight cap rock, gas reservoirs are formed. Cap rock is a harder or more resistant rock type overlying a weaker or less resistant rock type. Conventional production extracts natural gas from such sources with the aid of deep wells (as a rule deeper than 500 m). Unconventional natural gas is the collective term for thermogenic natural gas, which is still partially bound in the target rock or in dense reservoir rock. Tight gas is trapped in dense strata such as sandstone, limestone and clay minerals. It occurs in strata at depths of 3500 to 5000 m. Shale gas occurs in carbon-rich sediments such as argillaceous shale and oil shale, mostly at depths of 1000 to 5000 m. Coalbed methane occurs, in conjunction with (high rank) coal, at depths between 700 and 2000 m. Of the unconventional types of natural gas, shale gas offers the greatest resources (SRU, 2013). Dyrszka (2013a,b) presents an overview as well as potential health and environmental impacts of shale gas exploration and production.

Shale gas refers to methane gas trapped within underground deposits of shale, a sedimentary rock that consists of compressed mud or clay and other minerals. Key issues and responsible business practices for shale gas exploration and production were the subject of a review by The Climate Principles (2013). The Marcellus shale gas 'fracking' production process is shown in Figure 9.

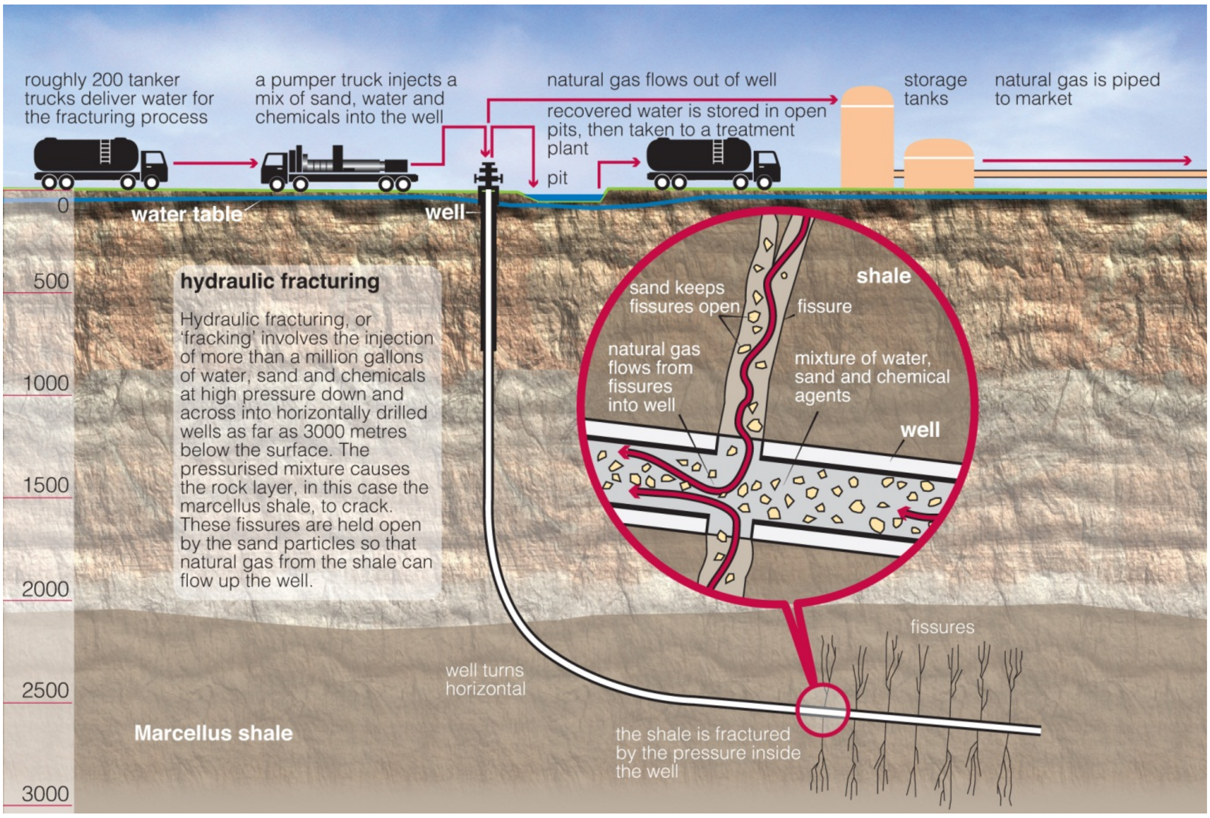


Figure 9 The Marcellus shale gas hydraulic fracturing (fracking) production process (The Climate Principles, 2013)

Figure 10 is a global map of potential, unconventional shale gas and coalbed methane formations (PACWEST Consulting Partners, 2015). While there are many similarities between shale gas and CBM and the methods used to extract them, there are also important distinctions. In particular, shale deposits are usually less porous than coal and are often located deeper underground. As a result, shale gas can be more difficult to extract than CBM, requiring greater use of extraction technologies such as hydraulic fracturing (also known as horizontal fracturing). Hydraulic fracturing, or 'fracking', is a technique used to boost the flow of gas from a new well. Large quantities of water and sand, together with certain, proprietary chemicals, are pumped into a newly drilled well at high pressure, to create fractures in the underground rock layers such as shale deposits. Gas can then migrate through the fractures, reaching the well much faster than it would otherwise. Glass (2011) produced a factsheet on shale gas and oil products and by-products.

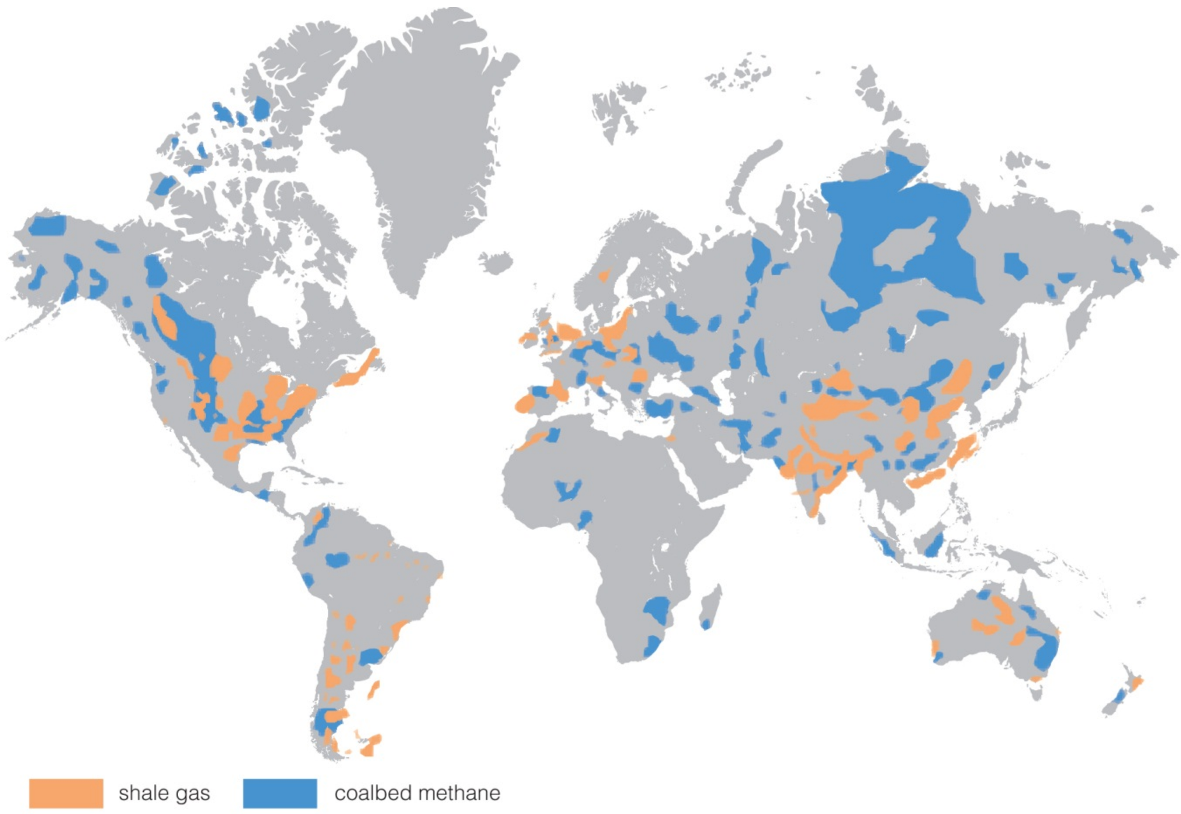


Figure 10 Global map of shale gas and coalbed methane (CMB) potential (PACWEST Consulting Partners, 2015)

The top 10 countries with technically recoverable shale gas resources according to the EIA (2013) are: shown in Table 4.

Table 4 Top 10 countries with technically recoverable shale gas resources (EIA, 2013)

Rank	Country	Shale gas, trillion cubic feet (Tcf), ~trillion cubic meters (Tm^3)
1	China	1115 (31.57)
2	Argentina	802 (22.71)
3	Algeria	707 (20.02)
4	USA	665 (18.83)
5	Canada	573 (16.23)
6	Mexico	545 (15.43)
7	Australia	437 (12.34)
8	South Africa	390 (11.04)
9	Russia	285 (8.07)
10	Brazil	245 (6.94)
	World Total	7229 (204.70)

The International Energy Agency published a review entitled 'golden rules for a golden age of gas' in 2012. It found that the share of unconventional gas in total gas production increases under the golden rules case from 14% in 2010 to 32% in 2035 (Figure 11). The golden rule case assumes that conditions are put in place to allow for a continued global expansion of gas supply from unconventional resources. This allows unconventional gas output to expand not only in North America but also in other countries around the world with major resources. Of the different sources of unconventional supply, tight gas, at 245 Bm^3, accounted for just over half of global unconventional production in 2010. However, it was rapidly overtaken in the projections by the exploration and production of shale gas, which rises from ~145 Bm^3 in 2010 (31% of total unconventional output) to 975 Bm^3 in 2035 (almost 60% of the total). Production of coalbed methane likewise grows rapidly, from 80 Bm^3 in 2010 to nearly 410 Bm^3 in 2035 (IEA, 2012).

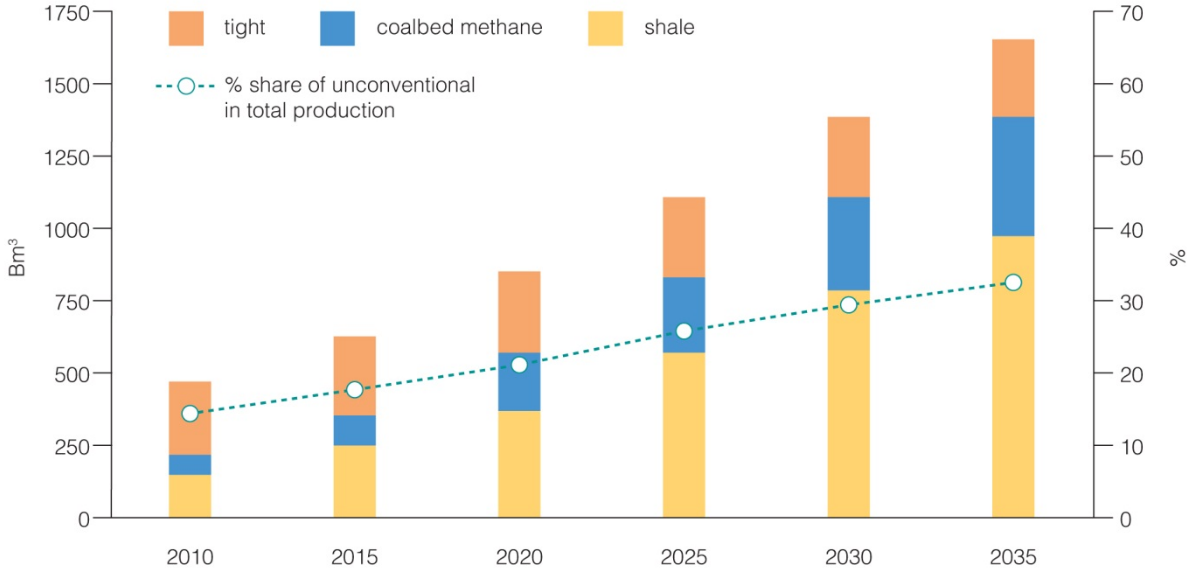


Figure 11 Current and projection of unconventional gas in total gas production under the IEA golden-rules case from 2010 to 2035 (IEA, 2012)

The extent of water use and the risk of contamination are key issues for any unconventional gas development. The issues have generated considerable public concern. In the case of a shale gas or tight gas development, though some water is required during the drilling phase, the largest volumes of water are used during the hydraulic fracturing process: each well can need anything between a few thousand and 20,000 m^3 (between 1 million and 5 million gallons). Therefore, efficient use of water during fracturing is essential. According to the IEA (2012), the amount of water required for shale gas or tight gas developments, calculated per unit of energy produced, is higher than for conventional gas.

The UK Department of Energy and Climate Change (DECC) (2014) agrees with the IEA (2012) findings in that hydraulic fracturing for shale gas is likely to use large quantities of clean water, although the amount used in fracking is not exceptional compared with other industrial activities. According to the DECC, each fracking operation requires between 10,000 and 30,000 m^3 (10,000 to 30,000 t or 2 to 6 million gallons) of water. The volume will depend on the site, but estimates suggest that the amount needed to operate a fracking well for a decade may be equivalent to the amount needed to run a 1000 MW coal-fired power plant for 12 hours. The water may be obtained from the local water supply company or taken 'abstracted' from surface or groundwater (if permitted by the relevant environmental regulator). In the UK, the environmental regulator will only grant a licence to an operator to abstract water where a sustainable water supply is available. Groundwater is defined as the subsurface water that is in the zone of saturation and is the source of water for wells, seepage, and springs. The top surface of the groundwater is known as the water table.

Potential groundwater contamination is considered an issue with hydraulic fracturing (NRDC, 2012). However, according to DECC (2014), the Royal Society and the Royal Academy of Engineering (2012), fractures resulting in gases or 'fracking fluid' escaping upwards into water sources in the UK, are highly unlikely. Nevertheless, in order to detect groundwater contamination, recommendations of the latter study included carrying out:

- comprehensive national baseline surveys of methane and other contaminants in groundwater;
- site-specific monitoring of methane and other contaminants in groundwater before, during and after shale gas operations;
- arrangements for monitoring abandoned wells; and
- data collection by operators and submittal of the said data to the appropriate regulator.

The study included many other recommendations including; ensuring well integrity, mitigating induced seismicity, detecting potential leakage of gas, managing water in an integrated way, managing environmental risks, implementing best practice for risk management, determining requirements to regulate the shale gas industry, and maintaining co-ordination of the numerous bodies with regulatory responsibilities for shale gas extraction. Finally, that the Research Councils, especially the Natural Environment Research Council, the Engineering and Physical Sciences Research Council and the Economic and Social Research Council, should consider including shale gas extraction in their research programmes, and possibly a cross-Research Council programme. Priorities should include research into the public acceptability of the extraction and use of shale gas in the context of UK policies on climate change, energy and the wider economy (The Royal Society and The Royal Academy of Engineering, 2012).

There are numerous studies on the subject of water contamination and shale gas exploration/extraction, for example, in addition to the above, *see* Engelder and others (2014), Klemow (2014), Peduzzi and Harding (2012) and Osborn and others (2011). Therefore, water issues related to fracking will not be discussed in further detail in this review.

According to Bradbury and others (2013), hydraulic fracturing is often an emissions-intensive process used to initiate production at both conventional and unconventional wells (that is, 'well completions'; *see* Figure 12).

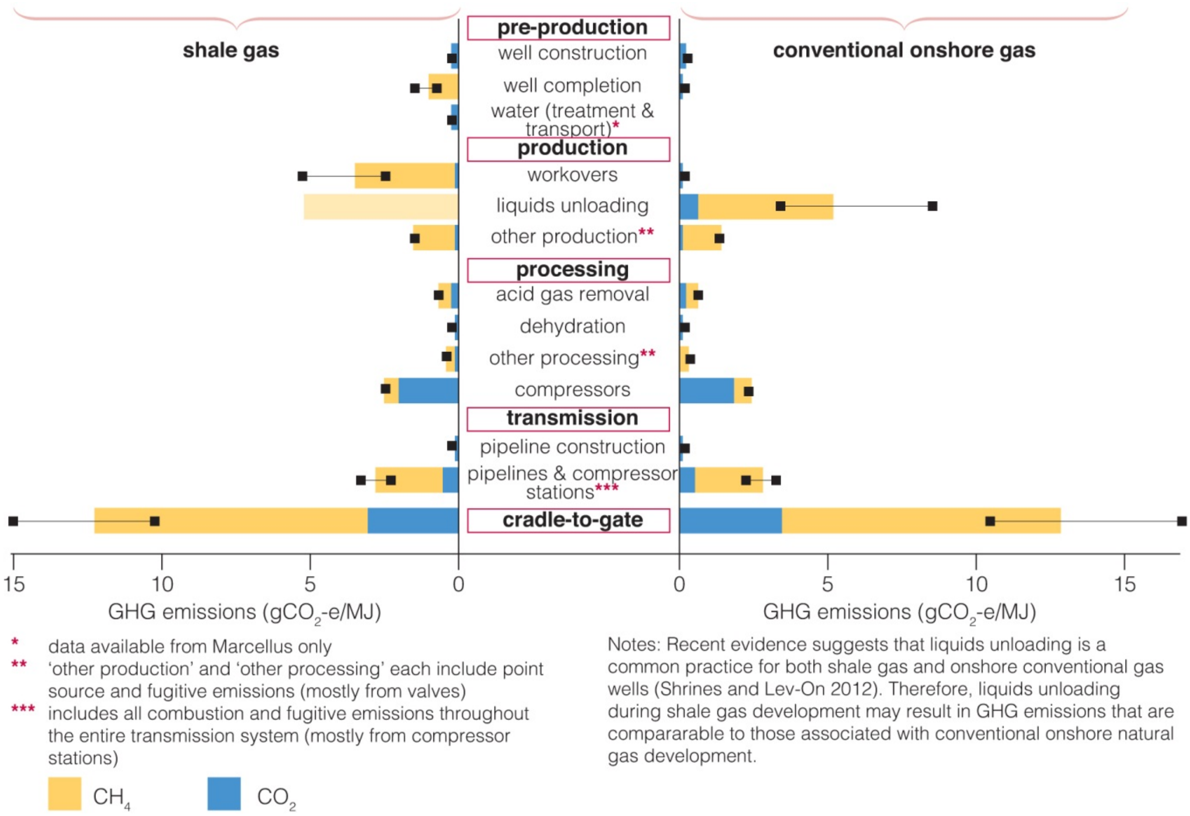


Figure 12 Comparing detailed estimates of life cycle GHG emissions from shale gas and conventional onshore natural gas sources (Bradbury and others, 2013)

It may be repeated to re-stimulate production multiple times over a well's estimated 20-to-30-year lifetime (during 'workovers'; *see* Figure 12). A well workover refers to remedial operations on producing natural gas wells to try to increase production. 'Liquids unloading' is a practice used to clean up all types of onshore wells, removing liquids to increase the flow of gas, and potentially causing significant emissions. Since 2009, the US EPA's annual GHG inventory has dramatically adjusted their emissions factors associated with these production-stage activities. In the EPA's draft 2013 GHG inventory, there was a 90% reduction in their estimates of emissions associated with liquids unloading in response to self-reported industry data showing that unloading events are less emissions-intensive than previously thought; that is, industry reported more frequent use of control technologies than the EPA had assumed in earlier inventories (Bradbury and others, 2013). Economic analysis of methane emission-reduction opportunities in the USA oil and natural gas industries was the subject of a review by ICF International (2014). ICF International (2014) found that by volume, the largest abatement opportunities target leak detection and repair of fugitive emissions (leaks) at facilities and gas compressors, reduced venting of associated gas, and replacement of high-emitting pneumatic devices. As for abatement by segment, the majority of the projected emissions are found in the oil and gas producing segments and the gas transmission segment. These three segments account for almost 70% of the projected reductions. Busch (2014) writes that the EPA needs to develop a plan to collect and analyse actual, real-world data to narrow the uncertainty ranges and provide a better understanding of methane emissions, especially from the natural gas system. The authors also consider that the *downward revisions* in the EPA inventory are being made despite increasing scientific evidence that the EPA should be *increasing* its estimate of methane emissions. New technologies for detection and measurement of methane emissions can help the EPA achieve this goal. Additional resources should be dedicated to this objective (Busch, 2014).

Shires and Lev-On (2012) presented a summary and analysis of results from a collaborative effort among members of the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) that gathered data on activities and equipment emission sources to develop estimates of methane emissions from upstream natural gas production. Based on the information gathered from the member companies during this project, the authors consider that the US EPA overstated several aspects of GHG emissions from unconventional natural gas production. According to Shires and Lev-On (2012), the ANGA/API survey data results show significantly lower emission estimates for liquids unloading and unconventional gas well re-fracturing when compared to the US EPA's emission estimates in the national inventory.

According to Bradbury and others (2013), research based on field measurements of ambient air near natural gas well-fields in Colorado and Utah suggest that more than 4% of well production may be leaking to the atmosphere at some production-stage operations. As there are currently hundreds of thousands of wells and thousands of natural gas producers operating in the USA, this continues to be an active debate. Data from the US EPA and other sources aim to clarify these questions in the near future. For example, independent researchers at the University of Texas at Austin with the Environmental Defence Fund and several industry partners are working on directly measuring methane emissions from several key sources. In March 2014, the Environmental Defence Fund (EDF) published a study carried out by ICF International on economic analysis of methane emission-reduction opportunities and selected mitigation technologies in the USA natural gas industries.

Shale gas has grown rapidly into a major industry in the USA where shale gas resources are among the world's largest. In 2010, shale gas accounted for 23% of natural gas production in the USA, up from less than 1% in the 1990s. By 2035, this is projected to reach 49%. The shale gas industry is projected to experience similar rates of expansion in several other major economic regions, including both Europe and China, where production is currently near zero, but is expected to grow to a major source by 2035.

In 2014, Brandt and others published a report on methane leaks from North American natural gas systems. The authors reviewed 20 years of technical literature on natural gas emissions in the USA and Canada. They found that (Brandt and others, 2014a,b):

- measurement at all scales, showed that official inventories consistently underestimate actual methane emissions with the natural gas and oil sectors as important contributors;
- many independent investigations and experiments suggest that a small number of 'super-emitters' could be responsible for a large fraction of the leakage;
- recent regional atmospheric studies with very high emissions rates are unlikely to be representative of typical natural gas system leakage rates and;
- assessments using 100-year impact indicators, showed that system-wide leakage is unlikely to be large enough to negate climate benefits of coal-to-gas substitution.

According to Brandt and others (2014a,b), life cycle analysis studies generally agree that replacing coal with natural gas has climate benefits. However, these life cycle analyses have relied heavily on US EPA greenhouse gas inventories. Updating these assessments with large uncertainty ranges (*see* Brandt and others, 2014a,b), still supports climate benefits from coal-to-gas substitution in the power sector over the typical 100-year assessment period.

On the 25th of July 2014, the US EPA Office of Inspector General issued a report stating that 'the EPA has placed little focus and attention on reducing methane emissions from pipelines in the natural gas distribution sector. In 2012, the EPA stated its intent to continue to evaluate the appropriateness of regulating methane. The 2013 Climate Action Plan calls for the EPA, in conjunction with other federal agencies, to develop a comprehensive interagency strategy to address methane emissions. The EPA does not currently regulate methane emissions from the distribution sector and has not partnered with the Pipeline and Hazardous Materials Safety Administration, which regulates pipeline safety, to control methane leaks. The EPA has a voluntary programme to address methane leaks – Natural Gas STAR – but its efforts through this programme have resulted in limited reductions of methane emissions from distribution pipelines. This is due largely to financial and policy barriers, including disincentives for distribution companies to repair non-hazardous leaks.

The agency needs to address additional issues to better assess progress from the voluntary programme and determine if future regulations are warranted. The EPA needs to set goals and track its progress in reducing emissions from distribution pipelines through its voluntary programme. In addition, the EPA needs to evaluate data from ongoing external studies to determine their usefulness for validating or updating its distribution pipeline emission factors. The emission factors that the EPA uses are based on a 1996 study, which has a high level of uncertainty. Two non-EPA groups are conducting studies that may be useful to the EPA. However, the EPA's involvement in the design or protocols of these studies has been limited'.

The Office of Inspector General (2014) recommended that the EPA:

- work with the Pipeline and Hazardous Materials Safety Administration to address methane leaks from a combined environmental and safety standpoint;
- develop a strategy to address the financial and policy barriers that hinder reductions from the distribution sector;
- establish performance goals;
- track distribution sector emissions and use that data to help determine if future regulation would be appropriate and;
- assess whether data from ongoing studies should be used to update distribution-sector emission factors.

The EPA agreed with the first two recommendations and provided corrective action plans that meet the intent of the recommendations. However, although the agency agreed partially with the remaining recommendations, the latter three are considered unresolved.

In Australia, hydraulic fracturing is not as widespread as in the USA in deposits exploited so far. This is because the coal deposits that contain CSG, which are relatively common in Australia, typically have a high permeability. This means that gas can migrate to wells more easily, even without fracturing, as well as allowing the use of 'in seam directional drilling' techniques, which enhance the flow of gas but are only possible in reasonably permeable seams. Directional drilling is the technique of drilling at an angle from a surface location to reach a target formation not located directly underneath the well pad. By contrast, shale deposits, which are a common source of gas in the USA, are generally much less permeable, and therefore require hydraulic fracturing to create economic gas flows. In Queensland, hydraulic fracturing is estimated to have been used in around 8% of CSG wells drilled to date. However, this proportion is expected to rise to between 10% and 40% as the industry and production increase.

In 2014, the European Commission in its final working document discussed the exploration and production of hydrocarbons (such as shale gas) using high volume hydraulic fracturing in the European Union (EU). In the last three years, a number of EU member countries have granted or are in the process of granting concessions and/or prospection/exploration licences. The countries include Denmark, Germany, Hungary, Netherlands, Poland, Portugal, Romania, Spain, Sweden and the UK. However, only Denmark, Germany, Poland, Romania, Sweden and the UK have already commenced exploration activities. Major unconventional natural gas resources in Europe are shown in Figure 13 (Zerhdoud, 2014).

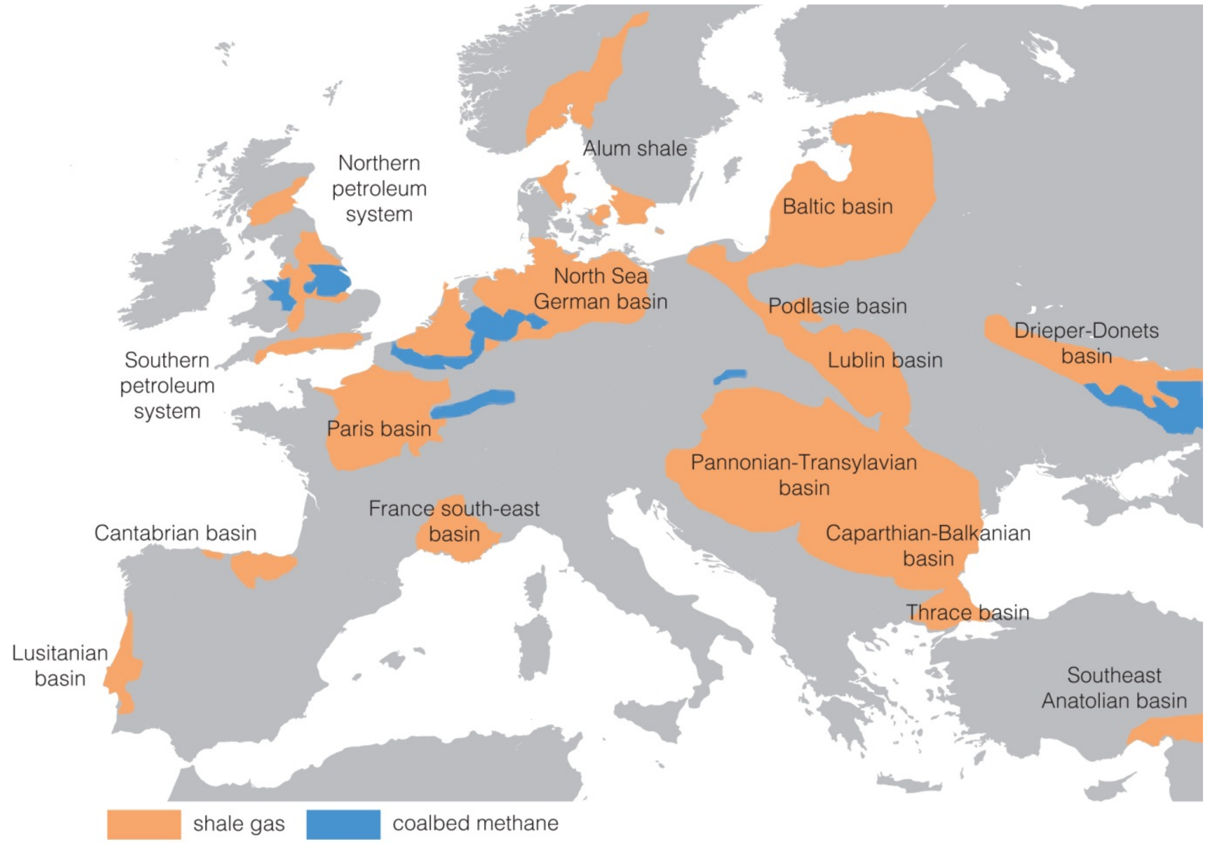


Figure 13 Major unconventional natural gas resources in Europe (Zerhdoud, 2014)

Zerhdoud (2014) discussed gas and hydraulic fracturing in France, Germany, Spain and the UK. The author considers that although many European states are more willing to consider shale gas to decrease heavy dependence on imports, for example Russian gas, environmental concern is at the core of a cautious approach with respect to hydraulic fracturing in many member states. Nevertheless, the conflict between Russia and Ukraine has reignited concerns about gas security. Although a few pilot production tests have been conducted (for example, in Poland), as yet, in 2014, there is no commercial production of shale gas in Europe. It is expected that commercial production could start in 2015-17 in some member countries such as Poland and the UK (European Commission, 2014a,b).

The German Advisory Council on the Environment issued statement no. 18 publication in May 2013 on fracking for shale gas production. The SRU (2013) identified two basic positions in the debate about fracking in Germany. On one hand, shale gas is expected to contribute to climate protection and the transformation of the energy system towards renewable energy sources. In addition, shale gas production is claimed to result in lower energy costs, thereby making the industry more competitive. On the other hand, there are objections to fracking, especially on the grounds that the use of hazardous substances leads to unjustifiable and uncontrollable risks for the environment. In their 2013 statement, the SRU highlighted the need for a differentiated assessment of the opportunities and risks of using fracking for shale gas production, and advocated a holistic approach that includes both energy policy and environmental policy aspects.

The SRU (2013) statement also considered that minimum requirements for the protection of health, environment and nature should be set for the pilot projects in order to rule out the possibility of drinking water contamination, and thus a general ban on fracking in water conservation areas is advocated. The same should apply to areas, which may be of potential future importance for drinking water abstraction, and to areas with tectonic conditions that could provide migration paths for gases and liquids. The statement discusses a framework condition for the use of fracking that mandates cooperation between the responsible technical authorities. The SRU is also of the opinion that where a deep exploration or production well is associated with fracking operations, there should be statutory provision for a mandatory Environmental Impact Assessment. In other deep drilling cases, there should be a preliminary Environmental Impact Assessment screening of the individual case. An investigation of the basic suitability of a site in each individual project should be a requirement, especially as regards the geological conditions, for example, the nature and thickness of the barriers to gas and water between the reservoir rock and the groundwater-bearing strata or the surface (SRU, 2013).

The SRU (2013) statement included the following conclusions regarding the use of fracking for shale gas production in Germany:

- fracking is not necessary from an energy policy point of view and cannot make a significant contribution to the German 'Energiewende', that is, the transition of the German energy supply system from oil, coal, gas and nuclear power towards renewable energies. By 2050, at the latest, at least 80% of the electricity supply and 60% of the entire energy supply is to originate from renewable energy sources. Initially, all nuclear power plants are to be shut down by 2022 and then

40% to 45% of the electricity supply, which currently stands at 25%, is to stem from renewable sources;

- fracking on a commercial **scale cannot 'currently' be allowed because of serious knowledge deficits;**
- **f**racking can only be justified on the basis of positive findings from systematically developed pilot projects.

Buchan (2012) discussed the 'Energiewende' in detail and concluded that Germany will probably succeed in achieving its renewable target for 2020 unless renewal subsidies are reduced dramatically. However, Buchan (2012) considers that Germany will probably miss its emission reduction target of 2020, as German GHG emissions were slightly higher than the EU average due to a relatively carbon-intensive energy mix. Buchan (2012) attributes this to the new added conventional capacity being based on coal/lignite.

Potoĉnik (2014) presented the Commission's recommendation on minimum fracking principles for the exploration and production of hydrocarbons (such as shale gas). For the purpose of the recommendation, hydraulic fracturing means injecting 1000 m^3 or more of water per fracturing stage or 10000 m^3 or more of water during the entire fracturing process into a well, and an installation includes any related underground structures designation for the exploration or production of hydrocarbons using high-volume hydraulic fracturing. In the recommendation, member states are responsible for decisions on their energy mix whilst considering environmental impacts. Therefore, in order to address public concern, although each state can decide whether to use fracking or not, conditions must be met. These include measures to prevent, manage and reduce the risks associated with such activities. In conclusion, the Commission recommends building on existing EU legislation and using, as well as improving, available practices and technologies. Member states currently exploring or planning to explore and produce unconventional hydrocarbon resources, such as shale gas, are called upon to implement and apply, and where necessary adapt, existing EU legislation to ascertain safe and secure development, taking into account possible effects on neighbouring countries. The aim of the Commission being to safeguard the environment, use the resources efficiently and keep the public informed whilst enabling potential energy security and competitiveness in member states who wish to use fracking (European Commission, 2014a).

Although the technique has been used extensively in the USA during the expansion of the shale gas industry since the 1990s, several countries have introduced restrictions due to possible environmental effects. According to Greeley & Stone (2014), several countries/regions have banned or introduced moratoria on hydraulic fracturing, for example, Bulgaria, France, Luxembourg, Ireland, the Cantabria regions (Spain) and some USA states such as New Jersey, New York and Vermont as well as some cities, for example, Pittsburgh, PA. For an up-to-date listing of activities in countries/regions/states with regard to a ban on fracking, *see* http://keeptapwatersafe.org/global-bans-on-fracking/. In Australia, Queensland has recently banned certain chemicals (benzene, toluene, ethyl benzene and xylene (BTEX) from being added to hydraulic fracturing fluids. A major issue highlighted recently is that during the first few days after well completion, 'flowback' water returning to the surface through the well can also be accompanied by fugitive methane emissions.

There have been significant developments regarding fugitive emissions, including methane, from gas exploration/extraction, especially shale gas. In 2011, the US Environmental Protection Agency (US EPA) concluded a review of the reporting rule methodologies for natural gas systems in the US Mandatory Greenhouse Gas Reporting Programme. This led to the introduction, on 23 December 2011, of new methods for the estimation of fugitive emissions from gas extraction, including requirements for additional direct sampling and measurement from wells where hydraulic fracturing is used. The latest USA national inventory submission to the United Nations framework convention on climate change (UNFCCC) (in 2011) also included new emission factors for exploration and production-gas well activities relating to shale gas. In 2012, these updated emission factors were reviewed through the UNFCCC Expert Review process. Additionally, several assessments of fugitive emissions from shale gas production have been published recently with a range of findings (Australian National Greenhouse Accounts, 2012).

According to the April 2014 US Energy Information Administration (EIA) report, based on the Oil and Gas Journal findings, as of January 2014, China holds 155 trillion cubic feet (Tcf) (~4389 billion cubic metres (Bm^3)) of proven natural gas reserves, the largest in the Asia-Pacific region. Natural gas production and demand in China rose substantially in the past decade. The country more than tripled natural gas production to 3.8 Tcf (~107.6 Bm^3) between 2002 and 2012. The government plans to produce ~5.5 Tcf (~155.7 Bm^3) of natural gas by the end of 2015 to replace other hydrocarbons in the country's energy portfolio. The EIA (2014) report projects long-term natural gas production in China to climb to 4.2 Tcf (~119 Bm^3) by 2020 and more than double from current levels to reach 10.1 Tcf (~286 Bm^3) by 2040.

According to EIA (2014), most of China's proven shale gas is in the southern and western regions and in the northern and northeastern basins. EIA estimates that China has the largest technically recoverable shale gas reserves in the world (1115 Tcf (~31,573 Bm^3)). Resource estimates of other sources are lower, for example, China's Ministry of Land and Resources (MLR) reported total shale gas technical reserves in 2012 as 883 Tcf (~25,004 Bm^3). Shale gas production in 2012 was 1.8 Bcf (~0.05 Bm^3) from test drilling, far short of the Ministry of Land Resources' goal to produce 230 Bcf (~6.5 Bm^3) of shale gas by the end of 2015 and at least 2100 Bcf (~59.5 Bm^3) by 2020.

In a working paper by the World Resource Institute, Bradbury and others (2013) discussed their findings on the upstream emissions of GHG – particularly methane – and their contribution to the climate impacts of USA natural gas production. The study focused primarily on evaluating and actions to reduce upstream methane emissions in the natural gas sector. The document did not address other aspects of natural gas development, including potential effects on water. However, toxic and volatile organic compound (VOC) emissions were discussed as the technologies and practices that effectively reduce those emissions typically achieve reductions in methane emissions.

The key findings of the working paper included (Bradbury and others, 2013):

- fugitive methane emissions from natural gas systems represent a significant source of global warming pollution in the USA. Reductions in methane emissions are needed as part of the broader effort to slow the rate of global temperature rise;
- cutting methane leakage rates from natural gas systems to less than 1% of total production would ensure that the climate impacts of natural gas are lower than coal or diesel fuel over any time horizon. This goal can be achieved by reducing emissions by one-half to two-thirds below current levels, through the widespread use of proven, cost-effective technologies;
- fugitive methane emissions occur at every stage of the natural gas life cycle; however, the total amount of leakage is unclear. More comprehensive and current direct emissions measurements are needed from this regionally diverse and expanding energy sector;
- recent standards from the US EPA will substantially reduce leakage from natural gas systems, but to help slow the rate of global warming and improve air quality, further action by states and the US EPA should directly address fugitive methane emissions from new and existing wells and equipment.

Bradbury and others (2013) consider that while a shift from coal to natural gas in power generation has resulted in reductions in CO_2 emissions in the USA, more will need to be done to meet the country's goal of reducing GHG emissions by 17% below 2005 levels by 2020. A WRI report found that cost-effective cuts in methane leakage from natural gas systems are among the most important steps that can be taken toward meeting that goal. Especially with the fast expansion in domestic natural gas production, which increases the risk of higher emissions unless, protections are put in place. In the longer term, policies are needed to address combustion emissions through carbon capture and storage or by other means.

In April 2014, the Policy Analysis Group of the American Gas Association (AGA) published a factsheet on emissions from natural gas systems. Also, in April 2014, the Environmental Protection Agency (EPA) released its annual inventory of US GHG emissions and sinks with updated estimates for natural gas emissions. According to AGA (2014), the inventory showed that the natural gas distribution systems have a small emissions footprint shaped by a declining trend. Using EPA estimates, the AGA (2014) consider that only 0.24% of produced natural gas is emitted from distribution systems owned and operated by local natural gas utilities. According to the US EPA (2014a), the emissions declined 22% since 1990 despite the addition of 600,000 miles of new pipeline, an increase of more than 30%. This is attributed to safety procedures and systematic upgrading of infrastructure through risk-based integrity management programmes. Methane emissions from natural gas distribution systems in the USA between 1990 and 2012 according to the US EPA (2014a) are shown in Figure 14.

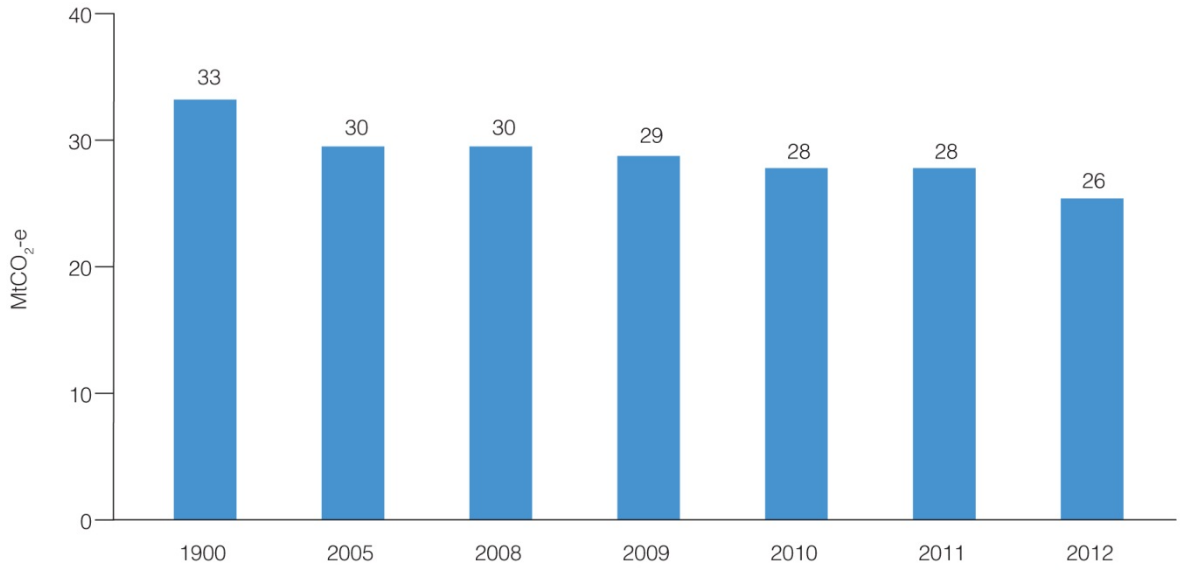


Figure 14 USA natural gas distribution systems methane emissions ($MtCO_2$-e) (EPA, 2014)

Methane emissions in 2012, by source, in the USA are shown in Figure 15. The emissions of 567Mt accounted for 9% of all US GHG emissions.

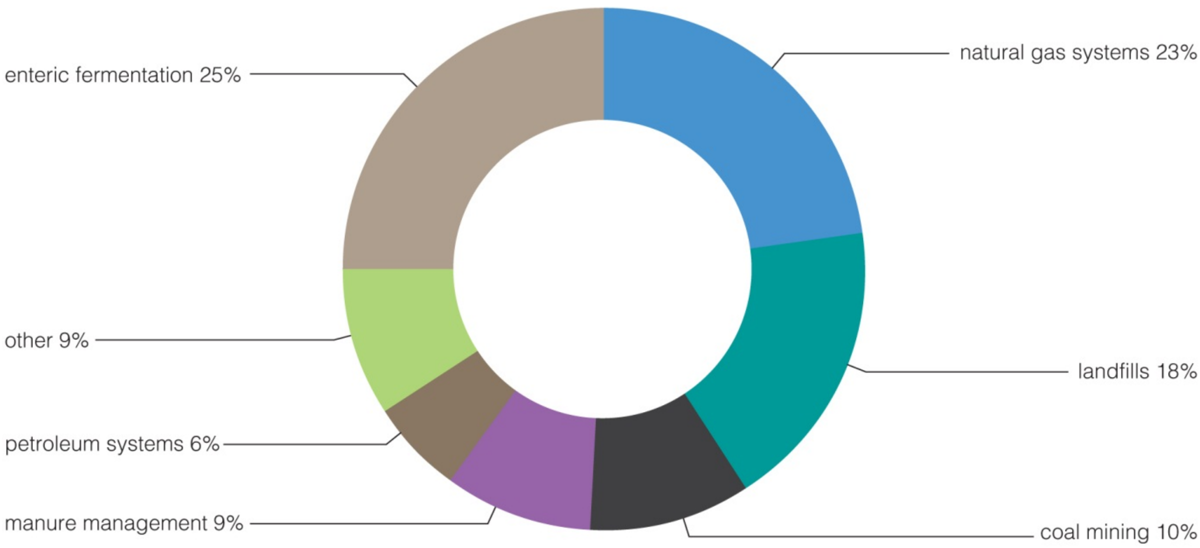


Figure 15 USA methane emissions by source (EPA, 2014)

According to AGA (2014), the US EPA categorises the natural gas system into four distinct stages: production, processing, transmission and storage, and distribution. Methane emissions from natural gas systems represent the second largest source category for methane in the USA constituting 23% of all methane released. In 2012, methane emission from natural gas systems equalled 130 Mt or 2% of total USA GHGs. The largest share stems from field production at 31% and processing at 15% (AGA, 2014).

O'Sullivan and Paltsev (2012) discussed potential versus actual GHG emissions from shale gas production in 2010. They estimated that, taking actual field practice into account, in 2010 the total fugitive methane emissions from USA shale gas-related hydraulic fracturing amounted to 216 kt. This represents 3.6% of the estimated 6002 kt of fugitive methane emissions from all natural gas production-related sources in 2010. In the same year, the entire natural gas value chain is estimated to have produced 10259 kt methane emissions, or ~3.1% of the USA total GHG inventory. Thus, O'Sullivan and Paltsev (2012) concluded that it is clear that increased efforts must be made to reduce fugitive methane emissions from natural gas systems.

Kirschke and others (2013) constructed decadal (3) budgets for methane sources and sinks between 1980 and 2010, using a combination of atmospheric measurements and results from chemical transport models, ecosystem models, climate chemistry models and inventories of anthropogenic emissions. Their results suggest that data-driven approaches and ecosystem models overestimate total natural emissions. Kirschke and others (2013) built three contrasting emission scenarios that differ in fossil fuel and microbial emissions, to explain the decadal variability in detected atmospheric methane levels. The authors found that although uncertainties in emission trends do not allow definitive conclusions to be drawn, observed stabilisation of methane levels between 1999 and 2006 may be explained by decreasing-to-stable fossil fuel emissions combined with stable-to-increasing microbial emissions. The renewed increase in global methane levels after 2006 was attributed to a probable rise in natural wetland emissions as well as fossil fuel emissions, although the relative contribution of these two sources remains uncertain.

The Marcellus shale natural gas reserve in Pennsylvania (USA) has been a significant energy discovery in the USA, with estimates indicating a 40–50 year supply of natural gas for Pennsylvania. It is considered by some that the Marcellus shale offers an abundant fuel to help bridge the gap between the current energy portfolio and a future resource that reflects both a reduced carbon footprint and security of supply. However, others have a distinctly opposing view due to the arguably detrimental environmental impacts of such development in Pennsylvania. The US DOE NETL is conducting a comprehensive assessment of the environmental effects of shale gas production at two Marcellus Shale test sites in south-western Pennsylvania (Washington County and Greene County). The NETL study aims to provide an unbiased, science-based source of information, which can guide decisions about shale gas development. It also aims to develop better methods to monitor environmental changes such as detecting methane emissions, water issues and seismic events, as well as develop technology or management practices to mitigate deleterious environmental impacts. On 5th November 2014, NETL released a list of new field laboratories and related research to help promote environmentally prudent development of unconventional oil and gas resources. Visit www.netl.doe.gov for more detail on the projects. Water withdrawals, and related issues, for development of Marcellus shale gas in Pennsylvania were the subject of a study by Penn State Extension (2010).

In order to achieve better understanding and quantification of methane emissions from shale gas development, Caulton and others (2014) discussed an aircraft-based, top down approach to measuring methane emissions. The approach enabled sampling of methane emissions between the regional and component level scales and identified plumes from single well pads, groups of well pads, and larger regional scales, giving more information as to the specific methane emission sources. Three types of flights over two days were undertaken in June 2012: investigative flights (I), mass balance flux (MB), and regional flux (RF). The results indicate a large regional methane flux in south-western PA, showing that the methane emission flux from the drilling phase of operation can be 2 to 3 orders of magnitude greater than inventory estimates, providing an example and improved understanding of the differences between observed data and bottom-up inventories. Caulton and others (2014) concluded that these high leak rates illustrate the urgent need to identify and mitigate these leaks as shale gas production continues to increase nationally. The results also indicate the need to examine all aspects of natural gas production activity to improve inventory estimates and identify potential opportunities for mitigation strategies and that top-down measurements provide an important complement to bottom-up inventory determinations. Shale gas production is expected to increase globally. Caulton and others (2014) consider that, if a midrange value of the reported fraction of production that is emitted (7%) is applied to the projected global peak shale gas production rate, 23 trillion ft^3 per year (0.65 Tm^3/y), it would correspond to 24 Mt of methane emitted per annum, or ~4% of the current global total (natural and anthropogenic) methane emission rate. Further studies are needed according to Caulton and others (2014), to enable better understanding of the operational details that lead to the largest emissions, how they might be better controlled, and to provide a more detailed picture of the expected life cycle-integrated emissions from unconventional gas wells.

3.2 Power generation

In 2007, approximately 21% of world electricity production was based on natural gas when the global gas-fired generation capacity amounted to approximately 1168 GWe. There are two types of gas-fired power plants, open-cycle gas turbine (OCGT) plants and combined-cycle gas turbine (CCGT) plants. OCGT plants consist of a single compressor/gas turbine that is connected to an electricity generator via a shaft. They are used to meet peak-load demand and offer moderate electrical efficiency of between 35% and 42% (lower heating value, LHV) at full load. Their efficiency is expected to reach 45% by 2020. CCGT is the dominant gas-based technology for intermediate and base-load power generation. CCGT plants have basic components the same as the OCGT plants but the heat associated with the gas turbine exhaust is used in a heat-recovery steam generator (HRSG) to produce steam that drives a steam turbine and generates additional electric power. Large CCGT plants may have more than one gas turbine. Over the last few decades, advancement in technology has meant a significant increase of the CCGT efficiency by raising the gas-turbine inlet temperature, with simultaneous reduction of investment costs and emissions. The CCGT electrical efficiency is expected to increase from the current 52–60% (LHV) to some 64% by 2020. CCGT plants offer flexible operation. They are designed to respond relatively quickly to changes in electricity demand and may be operated at 50% of the nominal capacity with a moderate reduction of electrical efficiency (50–52% at 50% load compared to 58–59% at full load) (Seebregts, 2010).

4 Methane and other greenhouse gases

The Intergovernmental Panel on Climate Change (IPCC) has identified six greenhouse gases (GHGs):

Carbon Dioxide (CO_2)	Fossil fuel combustion, forest clearing, cement production.
Methane (CH_4)	Landfills, production and distribution of natural gas and petroleum, fermentation from the digestive system of livestock, rice cultivation, fossil fuel combustion.
Nitrous Oxide (N_2O)	Fossil fuel combustion, fertilisers, nylon production, manure.
Hydrofluorocarbons (HFCs)	Refrigeration gases, aluminium smelting, semiconductor manufacturing.
Perfluorocarbons (PFCs)	Aluminium production, semiconductor industry.
Sulphur Hexafluoride (SF6)	Electrical transmissions and distribution systems, circuit breakers, magnesium production.

Each GHG has active radiative or heat-trapping properties. To compare GHGs, they are indexed according to their Global Warming Potential (GWP). GWP is the ability of a GHG to trap heat in the atmosphere relative to an equal amount of CO_2. Carbon dioxide assumes the value one (1). Though the most prevalent, CO_2 is the least powerful GHG. GHGs can now be expressed in CO_2 equivalents often using the unit MMTCDE, or million metric tonnes of CO_2 equivalents. The GWP of the six GHGs given in the IPCC 1995 assessment report for a time horizon of 100 years, were CO_2 – 1, CH_4 – 21, N_2O – 310, HFCs – 140~11,700, PFCs – 6500~9200 and SF6 – 23,900. For the first and successive IPCC reviews on full scientific and technical assessment of climate change *see* https://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml#1.

The IPCC published its working group III assessment report in 2014. The IPCC (2014) considers that between 2000 and 2010 increased use of coal relative to many other energy sources reversed a pattern of gradual decarbonisation of global energy supply (high confidence). Increased use of coal, especially in developing Asia, increased the burden of energy-related GHG emissions. Estimates indicate that coal, and unconventional gas and oil resources are large; therefore reducing the carbon intensity of energy may not be primarily driven by fossil resource scarcity, but rather by other driving forces such as changes in technology, values, and socio-political choices. The Committee on Climate Change (CCC) published a briefing on the IPCC report on the 17th of April 2014. The briefing questioned whether the IPCC endorsed unconventional gas. According to the CCC (2014), the IPCC report discusses the expansion of low-carbon technology deployment required in order to avoid extensive climate change. Alongside these, and playing a diminishing role over time, it sets out the role for unabated fossil fuels as follows. Meeting long-term goals will significantly reduce coal use, followed by unconventional oil and gas use, with conventional oil and gas affected the least. Over time, there is limited scope for use of fossil fuels with conventional technologies, particularly in power generation. Using natural gas (*including shale gas produced with* *low-emissions practices*) in a modern gas-fired plant would reduce emissions per kWh by half when switching from the current world-average coal-fired power plant, evaluated using 100-year global warming potentials. Unconventional gas could therefore, according to the IPCC (2014), lower emissions for the transitional period where gas competes with coal, *if gas losses and additional energy requirements for the hydraulic fracturing process can be kept relatively small*. However, the IPCC (2014) reiterates that there is a gap in knowledge concerning fugitive methane emissions in gas systems, and also adverse environmental side effects associated with the increasing exploitation of unconventional gas (CCC, 2014).

Global anthropogenic CO_2 emissions into the atmosphere in 2013 are estimated to be 38.8 Gt of CO_2 (10.6 Gt of carbon), the highest in history and about 46% higher than in 1990. Global CO_2 emissions from the use of fossil fuel are estimated to have increased in 2013 by 2.1% compared with the average increase of 3.1%/y from 2000 to 2012. Since the industrial revolution more than two centuries ago, approximately 30% of the anthropogenic CO_2 emissions have been taken up by the ocean, and about 30% by land vegetation. The remaining 40% of emissions have led to an increase in the concentration of CO_2 in the atmosphere. The origin of CO_2 in the atmosphere can be determined by examining the different types (isotopes) of carbon in air samples. This identifies the additional CO_2 as coming from human activities, mainly the burning of fossil fuel, and not from natural sources (CSIRO, 2014). In 2012, the average emissions in the European Union (EU) were 19.2% below 1990 levels. The downward trend is expected to continue in the second commitment period 2013-20 (Bruyninckx, 2014).

According to the Global Methane Initiative (GMI, 2014), global anthropogenic methane emissions for 2010 were estimated at 6875 $MtCO_2$-e. Approximately 50% of these emissions are estimated to have come from the five sources: agriculture, coal mines, landfills, oil and natural gas systems, and wastewater (*see* Figure 16).

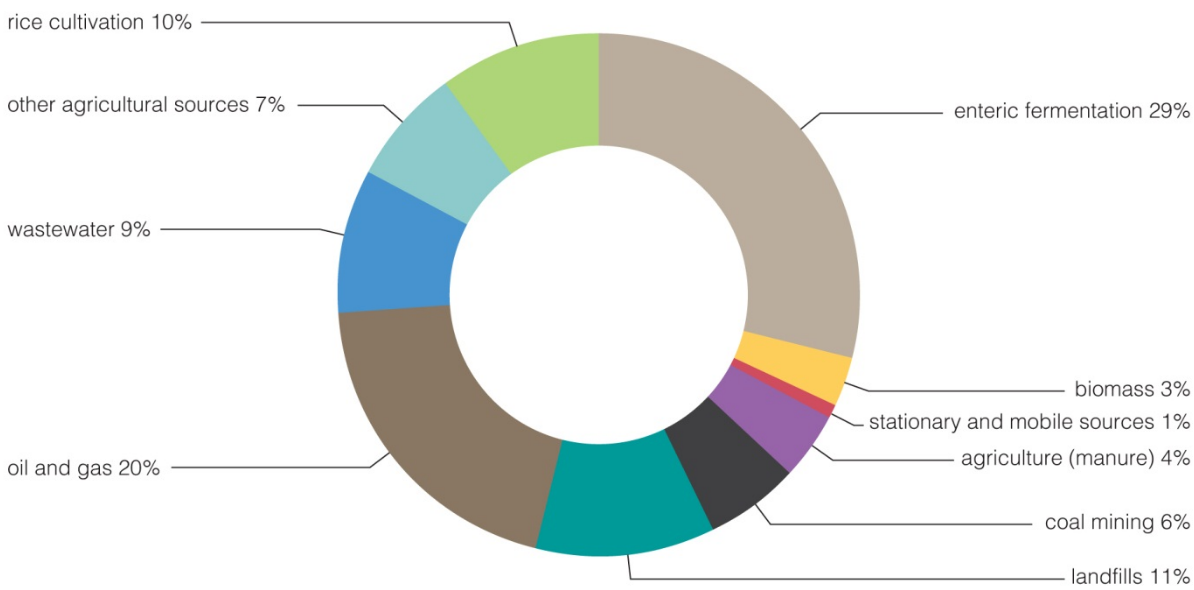


Figure 16 Estimated global anthropogenic methane emissions by source, 2010 (GMI, 2014)

Global anthropogenic methane emissions are projected to increase by 15% to 7904 $MtCO_2$-e by 2020 (*see* Figure 17).

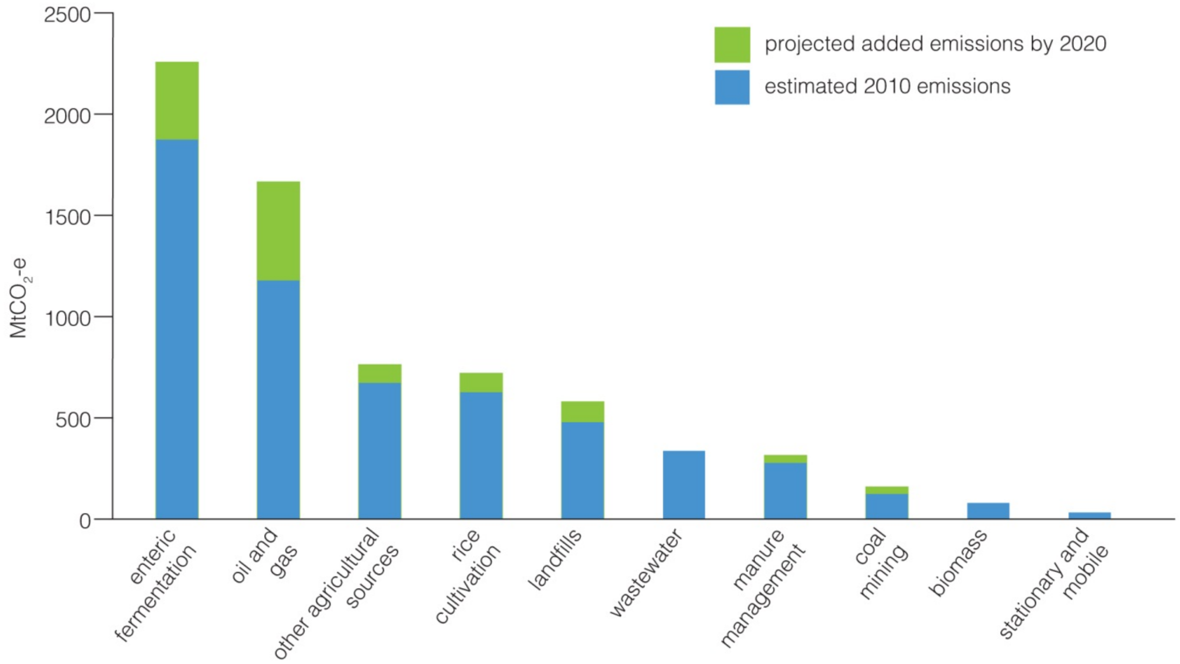


Figure 17 Estimated and projected global anthropogenic methane emissions by source, 2010 and 2020, $MtCO_2$-e (GMI, 2014)

From 2010 to 2020, the relative contributions of the agriculture, coal mining, and landfill sectors are projected to remain relatively constant, changing by less than 1% of global anthropogenic methane emissions or approximately 7–10% within each sector (*see* Figure 18).

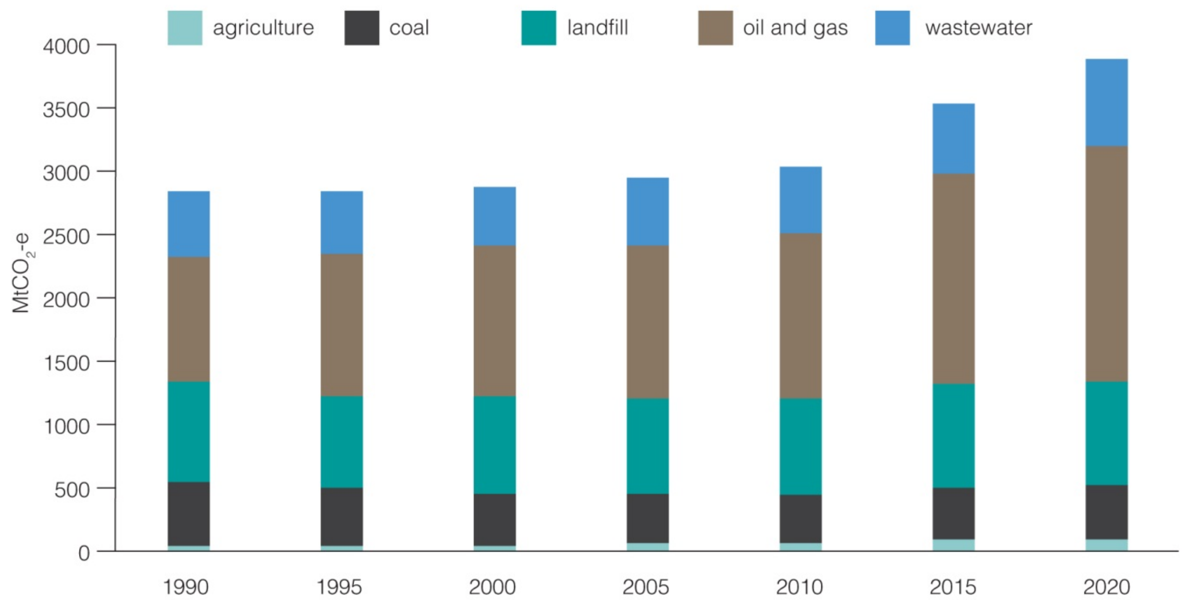


Figure 18 Global methane emissions by sector, $MtCO_2$-e (GMI, 2014)

Methane emissions from wastewater treatment systems are expected to increase by nearly 12%. Oil and gas emissions, however, are expected to increase by nearly 35% from 2010 to 2020, and will account for 3% more of the projected global anthropogenic methane emissions annually (GMI, 2014).

According to CSIRO (2014), most of the CO_2 emissions from human activities are from fossil-fuel combustion and land-use change. Figure 19 shows the sources of increased atmospheric CO_2 concentrations (1840-to date). Emissions are expressed in Gigatonnes of carbon per year (Gt C/y). A Gt is equal to 1 billion tonnes. One tonne of carbon (C) equals 3.67 tonnes of CO_2.

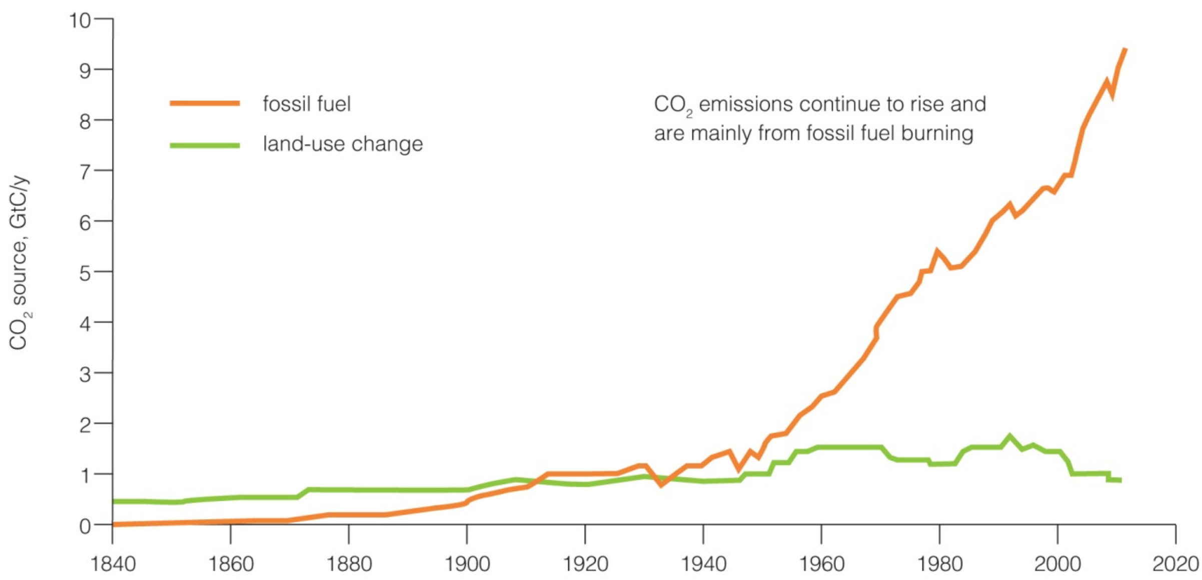


Figure 19 Increased atmospheric CO_2 sources and sinks (1840-to date) (CSIRO, 2014)

Figure 20 shows CO_2 emissions from human activities taken up by the ocean, by land vegetation (negative values are uptake) or remaining in the atmosphere.

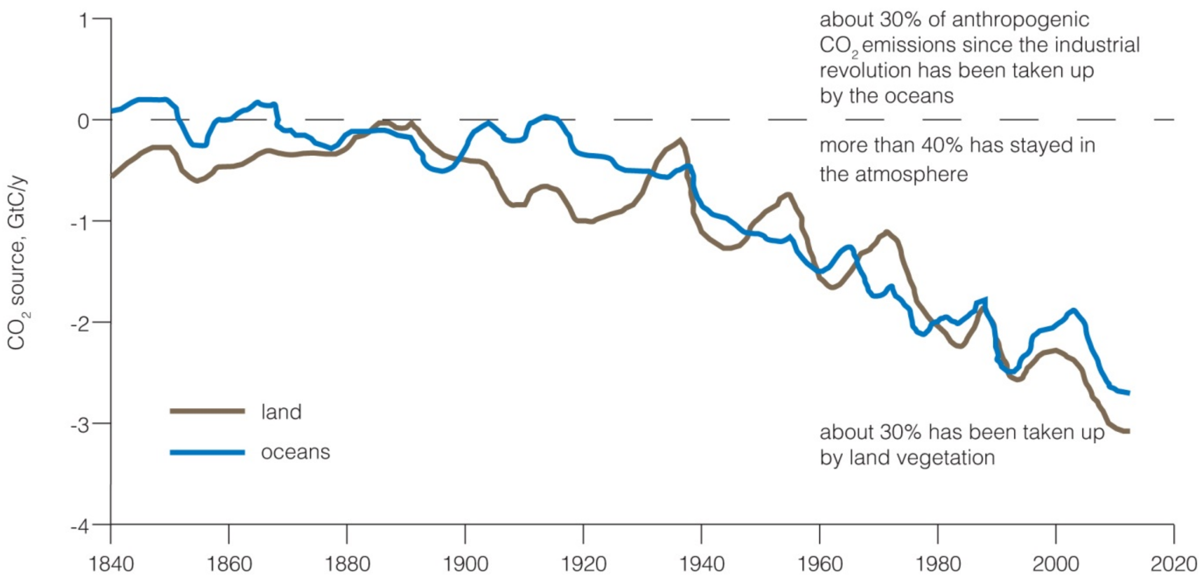


Figure 20 Sinks of CO_2 (CSIRO, 2014)

Figure 21 shows that there has been an increase in the atmospheric concentration of CO_2 since the year 1000, as identified by the trend in the ratio of different types (isotopes) of carbon in atmospheric CO_2. The CO_2 and carbon-13 isotope ratios in CO_2 (δ13C) were measured from air in Antarctic ice and firn (compacted snow) samples from the Australian Antarctic Science Programme, and at Cape Grim (northwest Tasmania).

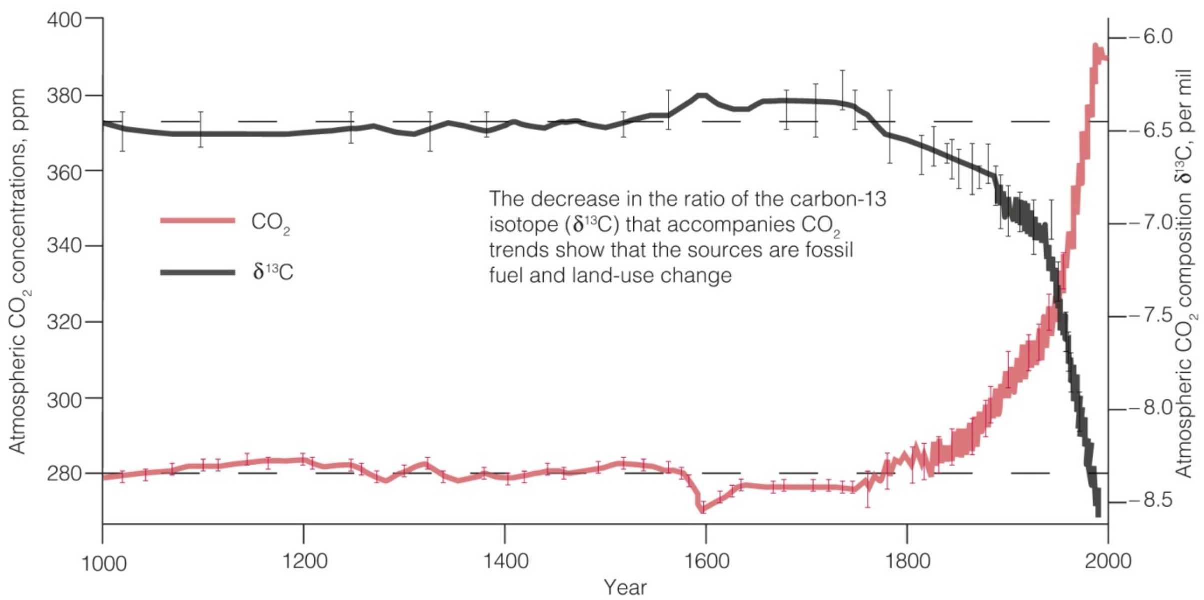


Figure 21 Concentration and isotopic composition of atmospheric CO_2 (CSIRO, 2014)

Atmospheric concentrations of major greenhouse gases, including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and a group of synthetic greenhouse gases, continue to increase (*see* Figure 22). The global mean CO_2 level in 2013 was 395 parts per million (ppm) – a 43% increase from pre-industrial

(1750) concentrations. The global CO_2 annual increase from 2012 to 2013 was 2.5 ppm, and the increase of 5.1 ppm since 2011 is the largest two-year increase observed in the historical record. Global atmospheric methane concentration is 151% higher, and N_2O 21% higher than in 1750. The impact of all greenhouse gases in the atmosphere combined, expressed in equivalent-CO_2 atmospheric concentration, reached 480 ppm in 2013 (CSIRO, 2014).

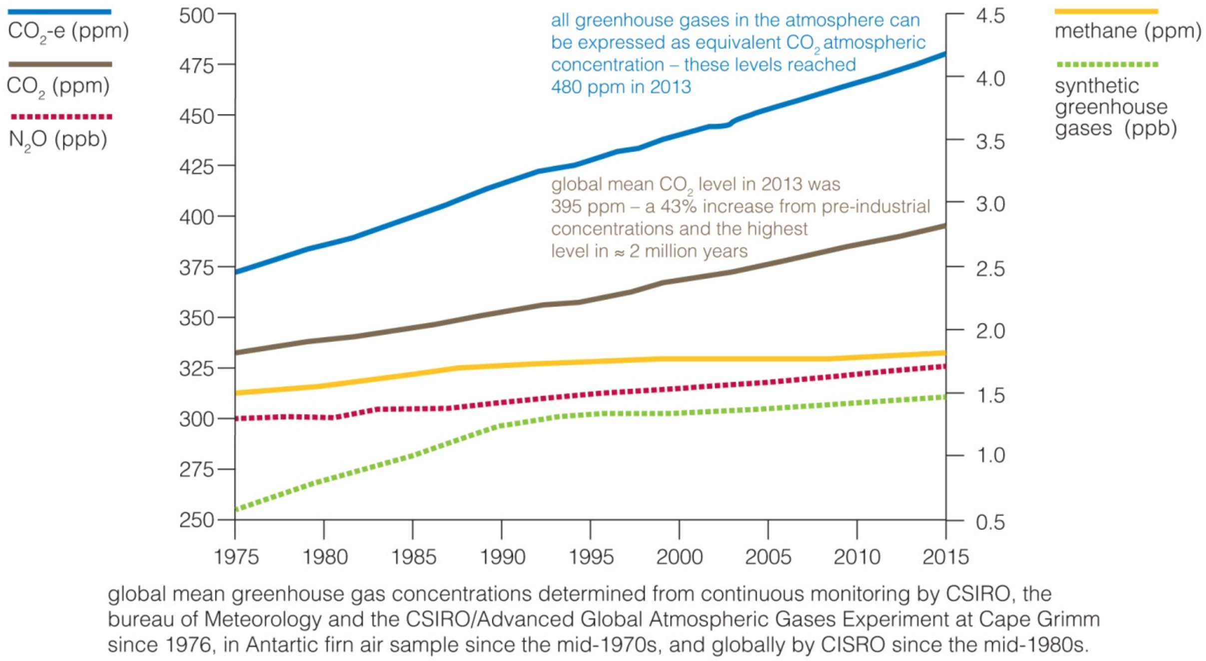


Figure 22 The increasing atmospheric concentrations of major greenhouse gases, including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and a group of synthetic greenhouse gases (CSIRO, 2014)

5 Sulphates

Sulphur dioxide (SO_2) emissions from coal combustion have decreased in numerous countries throughout the world over the last 4 decades, most significantly in North America, Europe and Japan. This is mainly due to the use of flue gas desulphurisation (FGD) technologies to reduce emissions or switching to lower sulphur content coals. On a regional scale, the sources of SO_2 continue to increase with greater utilisation of coal for power generation in non-OECD countries. However, increasingly stringent legislation, throughout the world, continues the drive towards reducing SO_2 emissions from coal utilisation. SO_2 emissions are important because unlike with coal combustion, SO_2 emissions from gas combustion are negligible. Switching energy production from coal to gas reduces CO_2 emissions and can lead to reduced climate impact (warming) in the long term, but, this is offset to some extent by the effects of reduced SO_2 emissions which lead to lower aerosol loadings in the atmosphere and an attendant warming (Wigley, 2011).

5.1 SO_2 emissions and sulphates

Natural sources of sulphur in the atmosphere are dominated by oceanic emissions of dimethyl sulphide (DMS) and predominantly SO_2 from volcanoes. Other natural sources include vegetation and soils. If sea spray is ignored, which is legitimate as 90% is returned to the ocean, natural emissions of SO_2 are in the range 27–68 Mt(S)/y. Emissions of sulphur due to human activities exceed natural emissions. The main human sources are coal and oil combustion, and smelting. In 2009, SO_2 emissions resulting from human activities were approximated at 90 Mt. OECD countries contributed 23% of this total. On a regional level, emissions of SO_2 continue to decrease in North America and Europe due to increasing energy efficiency, pollution control technologies, fuel substitution and implementation of legislation. Relevant legislative measures include the Clean Air Act, with the Acid Deposition Control Programme in the USA, and the Second Sulphur Protocol of the UNECE convention on Long-Range Transboundary Air Pollution in Europe. In non-OECD Asia, especially China and India, emissions of SO_2 continue to increase. Implementation of pollution controls for a Current Policies Scenario will result in an 8% decrease in world emissions of SO_2 in 2020 compared with 2009. The Current Policies Scenario provides a baseline picture of how global energy markets could develop were government policies to remain as they are. This is a combined result of reducing emissions from OECD countries (by ~30%), an increase in India, and a decrease in China, Russia, South Africa, and the Middle East. After 2020, emissions from many non-OECD countries continue to rise, which will cause an increase in world emissions by about 3 Mt/y until 2035. Particularly remarkable is the increase in SO_2 emissions in India (Cofala and others, 2013).

The concentration of anthropogenic sulphate aerosols in the atmosphere has grown rapidly since the start of the industrial revolution. At current production levels, anthropogenic sulphate aerosols are thought to outweigh the naturally produced sulphate aerosols. The concentration of aerosols is highest in the northern hemisphere where industrial activity is centred. The sulphate aerosols absorb no sunlight but they reflect it, thereby reducing the amount of sunlight reaching the Earth's surface. SO_2 in the atmosphere has a life span of only a few days. It may be converted to sulphate in the gas phase or aqueous phase. In the gas phase, SO_2 reacts with OH to produce H_2SO_4. This reaction takes place mainly during the day, and may lead to the formation of new particles. Aqueous phase oxidation is responsible for 40–95% of sulphate formed in the atmosphere. Hydrogen peroxide is the main oxidant, but ozone dissolved in cloud water will also oxidise SO_2. Sulphates produced by aqueous phase oxidation will not form new particles but will modify the size distribution of the aerosol. The mean sulphate lifetime in the atmosphere is about one week and the average cloud cycle time is 1–2.5 days. Thus, sulphate may go through up to seven cloud condensation-evaporation events prior to removal from the atmosphere. When the sulphate aerosols enter clouds they cause the number of cloud droplets to increase but make the droplet sizes smaller. The net effect is to make the clouds reflect more sunlight than they would without the presence of the sulphate aerosols. Pollution from the stacks of ships at sea has been seen to modify the low-lying clouds above them. These changes in the cloud droplets, due to the sulphate aerosols from the ships, have been seen in pictures from weather satellites as a track through a layer of clouds. In addition to making the clouds more reflective, it is also believed that the additional aerosols cause polluted clouds to last longer and reflect more sunlight than non-polluted clouds. The additional reflection caused by pollution aerosols is expected to have an effect on the climate comparable in magnitude to that of increasing concentrations of greenhouse gases. The effect of the aerosols, however, will be opposite to the effect of the increasing atmospheric trace gases – cooling instead of warming the atmosphere.

The concentration of sulphates in the atmosphere is decreasing in North America and Europe, consistent with the decrease in SO_2 emissions. However, the relationship is not linear, mainly because sulphates are longer lived in the atmosphere, and their presence is more dependent on meteorological conditions.

Sulphate cooling and climatic change backscattering of solar radiation by sulphate aerosols is much greater than their dry mass concentration would suggest. This is because sulphate aerosols are small (sub-micrometre) so they stay longer in the atmosphere than soil or sea salt particles and because they absorb water readily. About 0.2–0.3% of incoming solar radiation is lost to space globally through sulphate aerosols from human activities, corresponding to an annual mean global cooling of −0.3 to −0.9 W/m^2. This is much more pronounced in the Northern Hemisphere where over 90% of the SO_2 emissions from human activities occur, −0.4 to –I W/m^2 as compared to about −0.1 to −0.3 W/m^2 in the Southern Hemisphere. The wide difference in results from different authors is mainly due to the expression for the light scattering efficiency. Cloud modifications by sulphates are more complex and thus even more difficult to quantify than the direct effect by backscattering. The most important effect appears to be the increased number of cloud droplets through sulphate aerosol formation in clouds and the resulting increase in cloud albedo. Albedo is the fraction of solar energy (shortwave radiation) reflected from the earth back into space. It is a measure of the reflectivity of the earth's surface. However, it is difficult to establish a relationship between the droplet and sulphate concentrations. This may be attributed to different mixing processes in clouds. Estimates of the global average cooling effect of sulphates from human activities due to increased albedo from cloud modifications are −0.3 to −1.3 W/m^2.

Possible effects of sulphate aerosols on cloud lifetime are not included in the estimates. These are not quantifiable at present.

According to Klimont and others (2013), while global sulphur dioxide emissions have generally declined since the mid-1970s, there was an upturn in emissions from 2000 to 2005. This raised the possibility that the increase might have offset, during that period, the warming from increasing greenhouse gas concentrations. However, the increase was short lived as global SO_2 emissions have decreased since about 2006, with a change in trend in China due to implementation of sulphur emission controls in the energy sector and further reductions in the USA and Europe (*see* Table 5). Decline in SO_2 emissions from China and planned reductions in shipping emissions – another source of SO_2 – combined with continued emissions control in industrialised countries are likely to lead to a further net decrease in global SO_2 emissions in the future. This will have regional and global consequences, decreasing the net negative radiative forces from SO_2 emissions that is 'masking' some of the impact of increasing greenhouse gases. Radiative Forcing (RF) is the measurement of the capacity of a gas or other forcing agents to affect that energy balance, thereby contributing to climate change. Put more simply, RF expresses the change in energy in the atmosphere due to GHG emissions. Klimont and others (2013) conclude that a continued decline in global SO_2 emissions will likely result in an increase in the rate of future climate change.

Table 5 Change in emissions from broad world regions from the GAINS* model estimate (Klimont and others (2013)

	Change in emissions (kt SO_2)	
Region	**2000-05**	**2005-10**
Africa	471	450
China	8203	-2559
India	1178	2655
Middle East	240	381
Other Asia and Pacific	-632	-295
Europe[1]	-2792	-3621
EECCA[2]	-229	628
Russian Federation	278	-1556
Latin America and Caribbean	-1946	-310
USA and Canada	-1447	-6660
International shipping	2260	1605
Global	5584	-9281

* The **G**reenhouse Gas and **A**ir Pollution **In**teractions and **S**ynergies (**GAINS**) model provides a framework for the analysis of co-benefits reduction strategies from air pollution and greenhouse gas sources. The International Institute for Applied Systems Analysis (IIASA) (Austria) runs the model. Today, GAINS implementation is global. The model distinguishes 165 regions including 48 European countries and 46 provinces/states in China and India. GAINS was launched in 2006 as an extension to the Regional Air Pollution Information and Simulation (RAINS) model which is used to assess cost-effective response strategies for combating air pollution, such as fine particles and ground-level ozone (*see* http://gains.iiasa.ac.at/models/).

[1] Excluding EECCA countries and Russian Federation.

[2] Eastern Europe, Caucasus and Central Asia (EECCA) includes countries of the Former Soviet Union (FSU) excluding Russian Federation and Baltic States (Lithuania, Latvia and Estonia) which joined the European Union (EU).

6 Coal versus gas – efficiency and utilisation

Upgrading the efficiency of the world's coal fleet to reduce CO_2 emissions was the subject of a recent review from the IEA Clean Coal Centre by Barnes (2014). Definition of subcritical, supercritical, ultra-supercritical and advanced ultra-supercritical boiler pressure and temperature profiles differs from one country to another. Approximately speaking, subcritical power plants operate at super-heater temperature and steam pressure of <540°C and <22.1 MPa respectively and can achieve 33–35% efficiency (net, HHV basis, firing high rank coal). Supercritical units operate at 22.1–5 MPa, 540–580°C temperatures and achieve 35–40% efficiency. Ultra-supercritical units operate at >25 MPa, 580/620°C with 40–45% efficiency while advanced ultra-supercritical units are expected to operate at 25–35 MPa, 700–725°C and achieve 45–52% efficiency.

According to Barnes (2014), a current state-of-the-art coal-fired plant operating with a high efficiency ultra-supercritical steam cycle will be more efficient, more reliable, and have a longer life expectancy than its older subcritical counterpart. Most significantly, it would emit almost 20% less CO_2 compared to a subcritical unit operating under similar duty. Developments in advanced ultra-supercritical steam cycles promise to continue this trend, and a plant operating at 48% efficiency would emit up to 28% less CO_2 than a subcritical plant, and up to 10% less than a corresponding ultra-supercritical plant (*see* Figure 23). Ultra-supercritical plants have been constructed and operated in Europe, Japan and the USA and more recently, in China. Further research and development effort to commercialise higher efficiency plants such as advanced ultra-supercritical units and integrated gasification combined cycle (IGCC) continues.

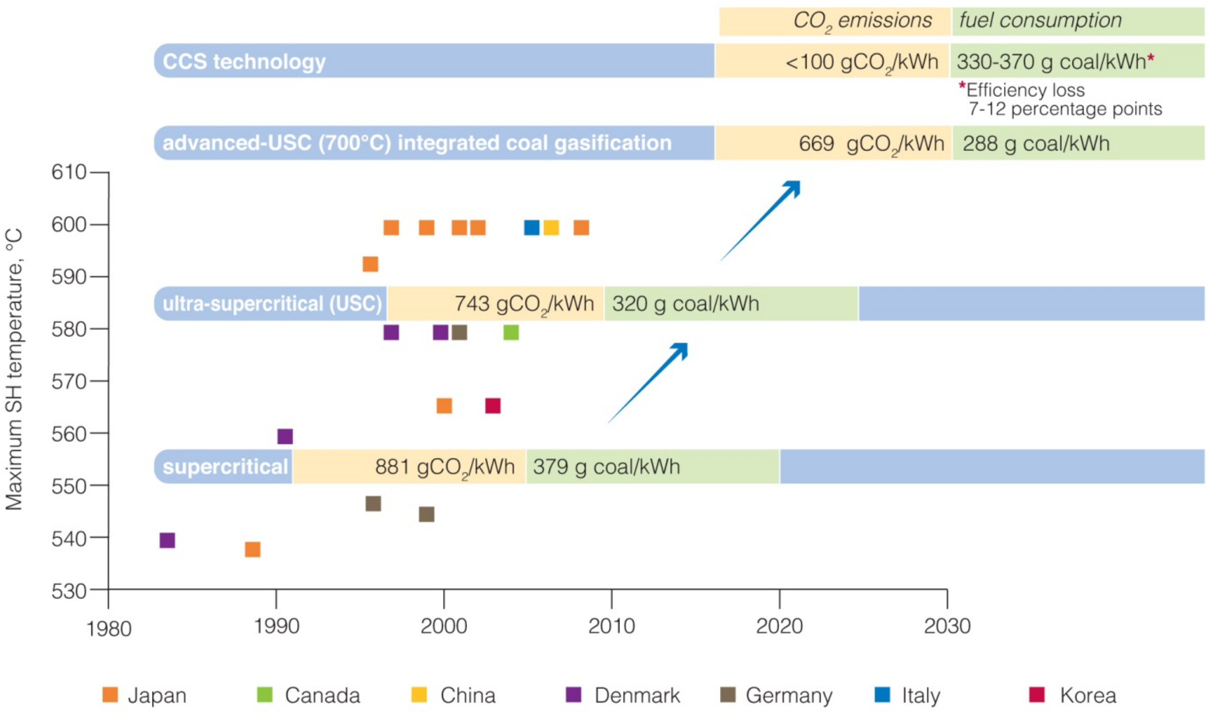


Figure 23 Development of supercritical, ultra-supercritical and advanced ultra-supercritical coal-fired plant (Barnes, 2014)

In 2011, Fulton and others analysed the emissions of CO_2, methane and N_2O emitted during the production, processing, storage, transmission, distribution and use of natural gas and coal in power plants. The survey of bottom up life cycle assessments led Fulton and others (2011) to conclude that:

- better quality data are essential to ensuring that life cycle GHG assessments remain up to date and reflect current industry behaviour. The assessments identified significant uncertainty around certain segments of the natural gas life cycle stemming from data inadequacy. Uncertainty sources identified included: formation-specific production rates, flaring rates during extraction and processing, construction emissions, transport distance, penetration and effectiveness of green completions and workovers and formation-specific gas compositions and;
- shale gas appears to have a GHG footprint 8–11% higher than that of conventional gas where methane emissions from the upstream portion of the natural gas production are unmitigated. This underlines the importance of implementing existing control technologies and practices that can minimise methane emissions and thus reduce the footprint of the natural gas industry.

The survey of top down life cycle assessments led Fulton and others (2011) to conclude that:

- on average, natural gas fired power generation emits significantly less GHGs compared to coal-fired power generation, however;
- compared to coal-fired power generation, methane emissions (including a large venting component) comprise a much larger share of natural gas generation GHGs.

Fulton and others (2011) consider that measurement of upstream emissions and public disclosure of the emissions requires improvement. However, methane emissions during production, processing, transport, storage and distribution of natural gas can be mitigated with moderately low cost technologies and best practices.

De Gouw and others (2014) discussed the reduction of CO_2, NOx and SO_2 emissions from USA power plants owing to the switch from coal to natural gas with combined cycle technology. The authors argued that these emission reductions must be weighed against emission reductions in other species such as mercury that are not included in the continuous emissions monitoring measurements, as well as the increased emissions of methane and volatile organic compounds (VOCs) associated with the production of natural gas. In particular, for shale gas, significant emissions of methane and VOCs have been observed. De Gouw and others (2014) discussed the findings of Howarth and others (2011), which concluded that the emissions of methane from shale gas production more than outweighed the reductions in CO_2 emissions. However, De Gouw and others considered that it should be noted that Howarth and others (2011) compared the direct CO_2 emissions of shale gas and coal on the basis of the heat content of the two fuels. Compared on this basis, the CO_2 emission intensity of natural gas is 60% of that of coal. For electric power generation, De Gouw and others (2014) consider this to be a more favourable value of 44%. This difference is attributed to a more efficient power generation process with natural gas than with coal. This may be the case for older subcritical facilities. However, advanced, modern supercritical and ultra-supercritical plants are capable of achieving efficiencies and emissions equivalent to those of natural gas combined cycle units (Dodero, 2007). The reduced efficiency issue was suggested to be a shortcoming in the Howarth and others (2011) analysis but was justified based on the fact that more natural gas is used for heating than for electric power generation (Howarth and others, 2012). An updated analysis of the GHG footprint of shale gas awaits comprehensive estimates of methane leakage rates from all important production areas in the USA. De Gouw and others (2014) consider that the updated analysis should also separate the use of natural gas for heating versus electric power generation, as their CO_2 emission intensities differ. Current USA methane leakage rates from natural gas systems are shown in Figure 24.

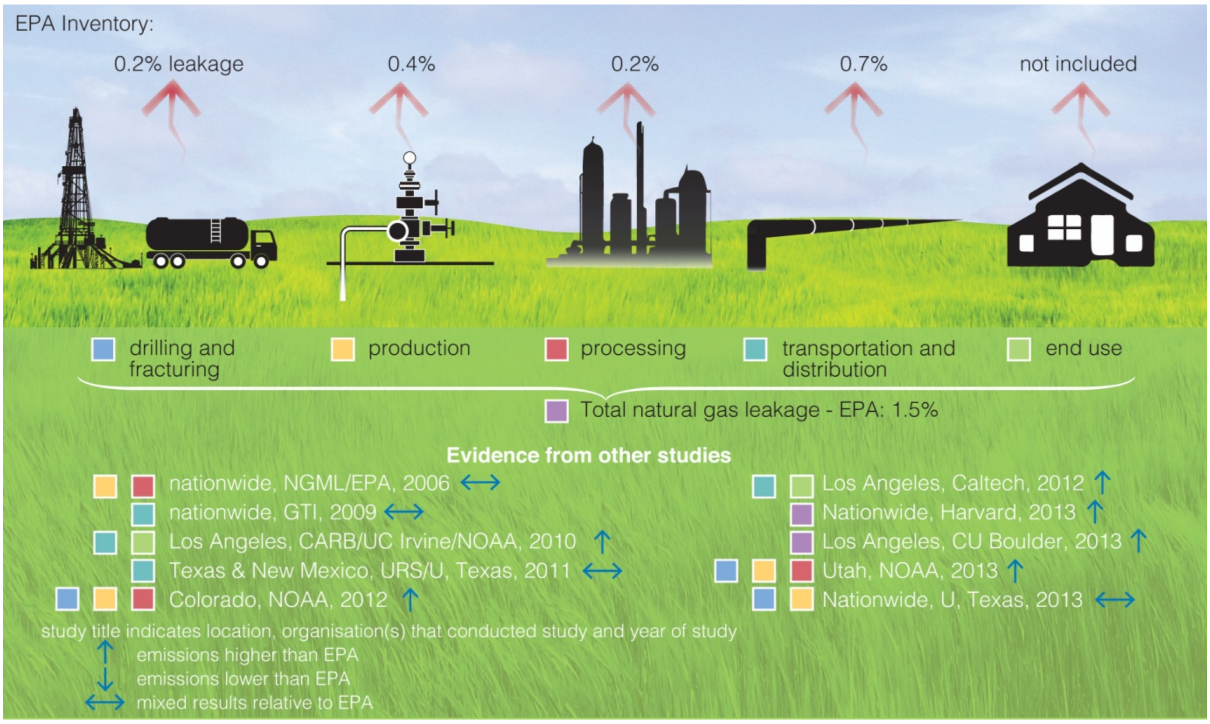


Figure 24 USA methane leakage rates from natural gas systems (Ekstrom, 2014)

In June 2014, Busch and Gimon questioned whether natural gas is better for the climate than coal. The paper analysed the level of GHGs attributable to electricity from natural gas-fired power plants compared to coal-fired power plants. The authors used an analytical framework that considers the key GHGs released during the production and combustion of coal and natural gas: carbon dioxide and methane. The unit of analysis used was a one megawatt-hour substitution of natural gas for coal – from existing plants. To enable summation with a single metric measurement unit, methane emissions were converted to carbon dioxide equivalent for three timeframes: time zero (immediately after the release of the gas), a 20-year time horizon, and a 100-year horizon. In addition to the time dimension, the methodology explored variations in power plant technology and rate of methane leakage from the natural gas system. Fuel cycle GHG emissions for different technologies at different levels of leakage were calculated and compared.

Busch and Gimon (2014) calculated the impact of natural gas on the margin and the threshold levels of methane leakage that would be required for natural gas and coal parity for four different natural gas and coal power plant technology couplets, representing factual situations. The framework analysed three plant technologies for each fuel type.

Coal test cases:

- new coal plant (heat rate = 8687 Btu/kWh (~9165 kJ/kWh)): supercritical pulverised coal plant. This is more efficient than the subcritical pulverised coal plant that makes up the bulk of the USA fleet. Their heat rates average 9370 Btu/kWh (~9886 kJ/kWh);
- system average (heat rate = 10,444 Btu/kWh (~11,019 kJ/kWh)): this is not a specific type of power plant but the system average, weighted by production, for coal plants operating in 2011;
- retired coal plant (heat rate = 11,665 Btu/kWh (~12,307 kJ/kWh)): the heat rate of the average of coal plants retired over the 2009-11 period.

Natural gas test cases:

- combined cycle H-Class plant (heat rate = 6093 Btu/kWh (~6428 kJ/kWh)): potentially the most efficient natural gas, commercially available, turbine plant. These are not the convention today, but could be in the future;
- new combined cycle plant (heat rate = 6798 Btu/kWh (~7172 kJ/kWh)): these plants achieve greater efficiency through a combination of direct use of gas to drive a turbine and secondary use of steam to turn another turbine. The heat rate of 6798 Btu/kWh (~7172 kJ/kWh) was used for the analysis;
- system average (heat rate = 8152 Btu/kWh (~8981 kJ/kWh)): this is not a specific type of power plant but the system average, weighted by production, for natural gas plants operating in 2011.

Btu/kWh (kJ/kWh) is a measure of the efficiency of a power plant. It is the amount of energy required to produce a unit of electricity. The conversion factor of a 100% efficient plant is 3413 Btu (~3601 kJ)= 1 kWh. The lower the heat rate, the greater the efficiency – typical values are: natural gas: 7,000–10,000 Btu/kWh (~7,385–10,550 kJ/kWh), coal: 8,000–10,000 Btu/kWh (~8,440–10,550 kJ/kWh) and biomass: 12,000–24,000 Btu/kWh (~12,660–25,321 kJ/kWh).

Considering all factors in the study, Busch and Gimon (2014) presented Figure 25, which gives an overview of fuel cycle GHG emissions for one MWh of electricity produced from coal versus natural gas – under different assumptions about leakage and power plant technologies, over different periods.

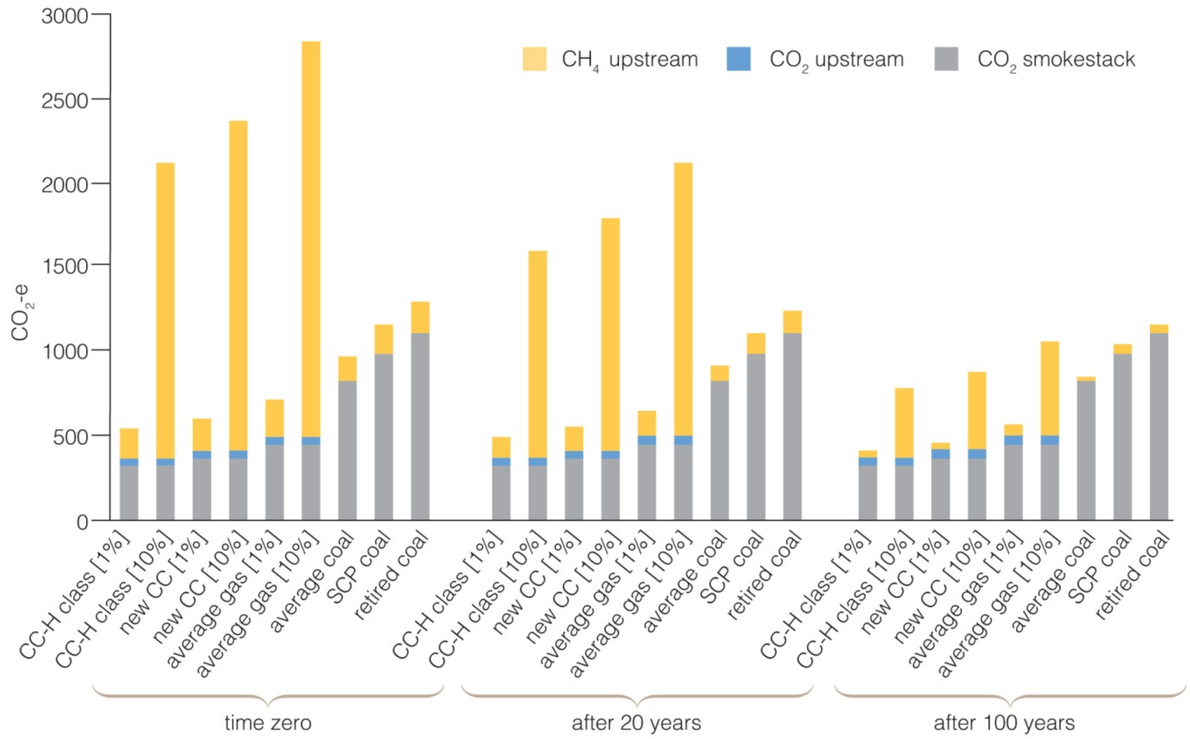


Figure 25 Fuel-cycle GHG emissions (kg) from 1 MWh of electricity produced (Busch and Gamon, 2014)

The upstream methane emission factor for coal is a derivation based on methane emissions from coal mining (EPA 2014) and the amount of coal produced in 2012. There is significant variability in upstream methane for coal, an issue not explored in the study. However, Busch and Gimon (2014) consider upstream methane from coal as a less important contributor to total GHG emissions compared to stack emissions or upstream methane from gas, and focus their sensitivity analysis on this factor. Upstream methane emissions from natural gas systems are calculated by defining a mass balance equation that accounts for methane from extraction to combustion at a natural gas power plant, recognising that the amount of gas produced must equal the amount of gas combusted, either at the power plant or upstream, plus the amount of gas leaked.

These results in Figure 25 illustrate the importance of technological assumptions when evaluating GHG emissions from fossil fuel fired electricity generation as, according to Busch and Gimon (2014), they have an importance, similar in magnitude, to methane leakage. For example, retired coal plant (over the 2009-11 period) has emissions 36% higher than new coal plant. For gas, H-Class gas is 33% better than system gas. Over the likely range of 2–4% in methane leakage, the magnitude of the impact is similar to differences due to technology. The difference in fuel cycle GHG emissions due to leakage at 4% versus 2% is 18% over 100 years, 39% over 20 years, and 49% at time zero.

Next, Busch and Gimon (2014) present the effect on GHG emissions due to a 1 MWh substitution of gas for coal under the technological specifications implied in the four different pairings described. A negative value indicates that the substitution of natural gas for coal would reduce CO_2 equivalent emissions. A positive value indicates that CO_2 equivalent emissions would be higher with natural gas as compared to coal. Their results are summarised in Table 6.

Table 6 Percentage change in GHG emissions due to a 1 MWh substitution of natural gas for coal (Busch and Gimon, 2014)

	Time zero	20 years	100 years
Results with 1% methane leakage			
Average gas versus retired coal	–45	–48	–43
Combined cycle versus system average coal	–49	–52	–46
Combined cycle versus supercritical coal	–38	–41	–47
Combined cycle H-Class versus supercritical coal	–44	–47	–52
Results with 10% methane leakage			
Average gas versus retired coal	120	73	–10
Combined cycle versus system average coal	105	61	–16
Combined cycle versus supercritical coal	150	96	3
Combined cycle H-Class versus supercritical coal	124	76	–8

Table 6 indicates that methane leakage rates strongly affect the impact of coal to natural gas substitution. At 1% leakage, natural gas provides some GHG gains over coal in every comparison. However, as methane leakage increases and at 10%, the short-term potency of methane is evident in that natural gas substitution results in higher emissions over the life cycle in every case at time zero and over the 20-year period. At the 100-year timescale and with 10% leakage, the results are; in three cases, natural gas emissions are higher and in one instance coal, emissions are higher.

Busch and Gimon (2014) also evaluated the level of methane leakage that would make natural gas fuel cycle emissions equivalent to those of coal. These are the breakeven points for natural gas, or threshold levels of methane leakage that need to be added, in order for natural gas to have fuel cycle GHG emissions as large as coal. The calculated threshold values under the various technology pairings and timeframes are shown in Table 7.

Table 7 Thresholds for methane leakage levels to increase natural gas emissions to equal coal (Busch and Gimon, 2014)

Leakage threshold	System gas plant versus retired coal plant, %	New combined cycle plant versus system coal plant, %	New combined cycle plant versus new coal plant, %	Combined cycle H-Class versus new coal plant
Time zero	3.6	4.0	2.9	3.5
20 years	4.8	5.3	3.6	4.6
100 years	11.8	13.2	9.6	11.5

Brandt and others (2014a,b) indicate that current leakage from the natural gas system is likely in the 2–4% range. The results evaluated by Busch and Gimon (2014) therefore imply that substituting natural gas for coal-fired electricity offer benefits in the long term. However, better information about the rate of leakage is needed to offer a definitive judgment of short-term effects. Over the 20-year time period, one of the four leakage thresholds for the study technology pairings falls within the feasible range of natural gas system leakage, but three of the thresholds are above the highest value that seems likely given the Brandt and others (2014a,b) findings. At time zero, thresholds are in the 2.9–4.0 per cent range. The uncertainty range around emissions from the natural gas sector will have to be reduced before conclusions that are more definitive can be reached about the GHG emission impacts of a substitution of one MWh from natural gas for coal over shorter periods, such as 20 years or less (Busch and Gimon, 2014).

Busch and Gimon (2014) concluded that there is an *urgent* need to reduce both short-term and long-term GHG emissions. There is also a need to minimise methane emissions including leakage from the natural gas supply, especially in the short-term, in order to make progress in averting measurable environmental impacts and economic damage from climate change.

China is the world's largest power generator. Net power generation was an estimated 4476 Terawatt hours (TWh) in 2011, up 15% from 2010, according to EIA (2014). Electricity generation increased by more than 89% since 2005, and EIA projects total net generation to increase to 7295 TWh by 2020 and 11,595 TWh by 2040, nearly three times the generation level in 2010. Although China plans to rely on more electricity generation from nuclear, other renewable sources, and natural gas to replace some coal to reduce carbon emissions and air pollution in urban areas, coal will continue to play a major role in the energy mix (*see* Figure 26).

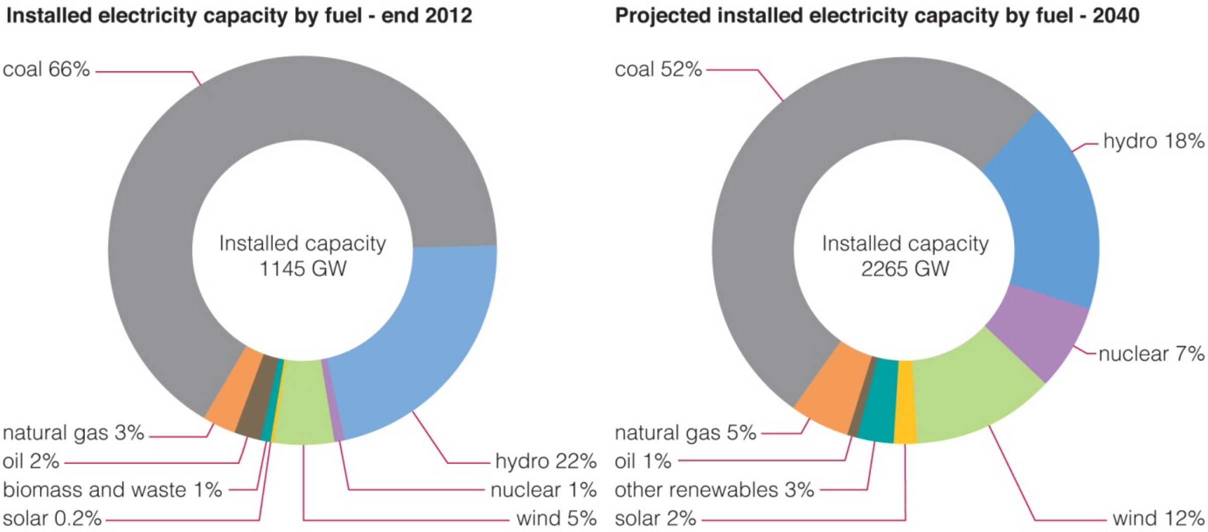


Figure 26 China's current and projected installed electricity capacity by fuel (2012-40) (EIA, 2014)

Coal will continue to be used as the main fuel for power generation, even as China diversifies its fuel supply and mix (EIA, 2014) According to Yuzhuo (2013), in the near term, coal will continue to dominate China's energy mix as well as in other non-OECD countries. The government in China has already shut down 80 GW of small, inefficient plants between 2005 and 2010 and is looking to continue the modernisation of its coal fleet in favour of larger, more efficient units as well as technologically advanced ultra-supercritical units. In addition, the authority has prohibited companies from building new coal-fired power plants around its three major cities, Beijing, Shanghai, and Guangzhou, where air pollution rates have become a problem in recent years. Nevertheless, the EIA (2014) projects that by 2040, China will bring on >450 GW of new coal-fired capacity.

According to the EIA (2014), in 2014, natural gas plays a small role in overall power generation and consists of 38 GW of installed capacity. However, the government plans to invest in more gas-fired power generating capacity whether gas is obtained from growing domestic sources and/or import alternatives. For example, coal-fired plants in Beijing, with a capacity of 2.4 GW, were planned to be replaced with gas-fired units by the end of 2014. However, although the first of these plants was shut-down in mid-2014, Beijing's three remaining coal-fired power plants are now to cease operation by the end of 2016. The EIA (2014) report indicates that overall, China's effort to shift coal-fired generation to more gas-fired generation in the long term depends on the country's ability to increase domestic production through shale gas and offshore reserves and imported sources.

Today, the energy market is undergoing changes driven by unconventional gas production. The dramatic increase in shale gas production in the USA is leading to the country becoming a net exporter of natural gas in 2018 (EIA, 2014). Other countries, such as China, also have significant reserves of unconventional gas, which could be used to satisfy future demand. However, the cost of gas varies greatly from region to region. For example, in Europe, the price of gas is currently four to five times greater than in the USA and six to eight times higher in the Asia-Pacific region. The discrepancies in pricing have and are forecast to continue to affect the utilisation of not only gas but also coal. Sikora (2012) viewed demand outlook in Europe (2011-20) for natural gas as a 'highly uncertain variable' quoting forecasts ranging from a 9% decrease to a 19% increase. An overview and comparison on the impact of global coal supply on worldwide electricity prices with a focus on Europe, USA, Australia, Japan, China and South Africa was the subject of an in depth review by the IEA Coal Industry Advisory Board (CIAB, 2014). Philippe and Cool (2014) discuss some of the key dynamics of the growing energy cost gap between the USA and Europe.

In the USA, more gas is expected to be used for power generation as well as in industry while coal utilisation is expected to increase in Europe to the end of this decade. Factors influencing the increasing appeal of natural gas include sufficient reserves, fuel flexibility and lower environmental emissions and therefore impacts compared to coal. Despite recent focus on methane emissions from shale gas exploration and development, coal utilisation is expected to decline somewhat not only in the USA but also in Europe in the long run. Older plants are expected to be decommissioned due to either age or inability to meet new regulations. These are expected to be replaced with renewable energy and natural gas plants. In the short term although the use of coal and gas for power generation is fluctuating, they continue to dominate with a share of 55% in 2035 (68% in 2008). Coal remains a main fuel for power generation but its share is forecast to drop from 41% in 2010 to 32% in 2035 (based on the IEA New Policies Scenario). Gas use for power generation was expected to remain stable in 2010 at around 21%. However, shale gas has resulted in the increased use of gas for power generation and the trend is expected to continue in some countries, such as the USA, where power generation with gas overtook coal in May 2012. In Europe and Asia, coal will continue to have a strong hold due to the higher gas prices (Nalbandian and Dong, 2013).

7 Climate impact of fuel switching

By 2040, according to the IEA (2014), the world's energy supply mix divides into four almost-equal parts: coal, gas, oil and low-carbon sources. Resources are not a constraint over this period, but each of these four faces a distinct set of challenges. However policy choices and market developments that bring the share of fossil fuels in primary energy demand down to <75% of what it is today, will not be enough to stem an estimated 20% rise in energy-related GHG emissions. However, electricity will continue to be in short supply. Approximately 7200 GW of capacity will need to be constructed to replace existing power plants due to retire by 2040, which account for 40% of the current fleet.

According to the IEA (2014), global coal demand grows by 15% to 2040, but almost two-thirds of the increase will be in the next decade. Chinese coal demand is expected to plateau at just over 50% of global consumption, before reducing after 2030. Demand is forecast to decline in the OECD, including the USA. India will become the world's second-biggest coal consumer before 2020, and surpass China soon after 2020, as the largest importer. The IEA (2014) considers that current low coal prices have put pressure on producers worldwide to cut costs, but the shedding of high-cost capacity and demand growth are expected to support an increase in price sufficient to attract new investment. China, India, Indonesia and Australia alone account for over 70% of global coal output by 2040.

By 2040, a >50% growth in demand is forecast for natural gas by the IEA (2014), especially since increasingly flexible global trade in LNG offers some protection against the risk of supply disruptions. The main regions that push global gas demand higher are China and the Middle East, but gas is also expected to become the leading fuel in the OECD energy mix by around 2030. This is due to new regulations in the USA limiting power sector emissions. Gas production is forecast by the IEA (2014) to increase almost everywhere (Europe being the main exception) and unconventional gas will account for almost 60% of global supply growth.

The top 12 countries with a descending percentage coal share in power generation in 2012 were South Africa: 93%, Poland: 87%, China: 79%, Australia: 78%, Kazakhstan: 75%, India: 68%, Israel: 58%, Czech Republic: 51%, Morocco: 51%, Greece: 54%, USA: 45% and Germany: 41% (WCA, 2014). Fuel switching, or substitution of high-carbon fuels with fossil fuels with lower carbon, on an energy content basis, is considered one of the principal methods to reduce greenhouse gas emissions from the energy sector. However, the topic was the subject of a document from the National Center for Atmospheric Research (NCAR) (USA) arguing that switching from coal to gas does little for the global climate (Wigley, 2011). It gives an account of a computer simulation study that concludes that substitution of coal by gas would be less beneficial than hitherto assumed, mainly due to methane leakage effects and their impact on the climate. Recent developments in shale-gas exploitation technology and economics have raised the prospects for substantially increasing global natural gas reserves and production. This has implications for substitution of natural gas for coal in power generation on a large scale in order to reduce environmental and global climate impacts of fossil power generation. However, according to Staple and Swisher (2011), the comparative GHG advantage of natural gas-fired power plants outweighs the negative GHG impact from the estimated rates of methane leakage from natural gas production, as long as the industry adopts available best practices and technologies to minimise and control such fugitive emissions. The conclusions were based on using the 2010 USA national inventory data, and standard international assumptions on the relevant time horizon for estimating the GWP of methane and other GHGs, Mackenzie (2012) listed a number of best practice technologies that can reduce fugitive methane emissions at relatively low cost and rapid payback. Yet, Hughes (2011), found that when compared on the basis of the average efficiency of the USA gas- and coal-electricity generation fleets, and on the basis of most efficient gas and coal technology, gas (shale) has higher emissions over a 20 year timeframe and lower emissions over a 100-year timeframe. Based on analysis of two conflicting studies, Hughes (2011) considered that regardless of which GWP is used; coal is likely to have a lower climate impact than gas (shale) over 30–40 years for the existing fleet, and 40–50 years comparing the most efficient technologies for coal- and gas-fired power generation. *Clearly, opinion was divided and continues to be divided today*.

The conventional wisdom holds that in a carbon constrained world of the future it will become necessary to require carbon capture and storage (CCS) for coal-fired power generation, but perhaps not for gas-fired generation, due to the lower carbon content of gas compared to coal on an energy content basis. The work from NCAR suggests that more in-depth analysis of the relative climate impact of coal versus gas under various circumstances and on various timescales may be needed. The risks and benefits of switching also involve conventional pollutant emissions; for example the global cooling influence of sulphate emissions from coal-fired power plants. In this review, analysis of the climate implications of coal-to-gas switching/substitution is presented.

Today, there is considerable, not only governmental, industrial, academic and public but also media attention focussing on the question of whether gas is 'better' than coal from a climate perspective. Klemow (2014) noted the strong public reaction to the development of and research on the impacts of fracking. Only studies – or parts of studies – that support a particular view are considered while other research, which does not meet with that view, is either discredited or simply rejected. The question of whether gas is less detrimental than coal from a climate perspective, has become more important since there are numerous older, inefficient coal-fired power plants still in operation despite upgrading some and retiring many and replacing them with natural gas-fired plants. However, the availability of coal and/or gas in a region plays a pivotal role in the choice of fuel for base-load power generation. At the point of combustion, natural gas is roughly half as carbon-intensive as coal. However, this comparison does not take into account the upstream fugitive methane emissions. According to Bradbury and Obeiter (2013), if fugitive methane emissions exceed 3% of total gas production, the climate advantage of natural gas firing over coal disappears over a 20-year time horizon.

In an early study, Hayhoe and others (2002) investigated the replacement of coal with natural gas in the electric power generation sector as a case study to evaluate the net effect of such substitution on climate. The authors used the Integrated Science Assessment Model (ISAM) to project the impact of switching from natural gas to coal, and the subsequent change in emissions, on global mean-annual near-surface temperature. ISAM consists of coupled modules for representation of the carbon cycle, effects of greenhouse gas emissions and aerosols on atmospheric composition, effects on global temperatures using an energy balance model, and processes affecting sea level change (http://climate.atmos.uiuc.edu/isam2/index.html). Using ISAM, analysis was conducted of the sensitivity of projected temperature change from CO_2, CH_4, SO_2 and black carbon (BC) emissions associated with coal and natural gas utilisation to key factors that affect emission rates and global temperature effects. Black carbon (BC) is the most strongly light-absorbing component of particulate matter (PM), and is formed by the incomplete combustion of fossil fuels, biofuels, and biomass. Four uncertain factors were considered: methane emissions from 1– natural gas use and 2– coal mining, and the radiative forcing associated with 3– sulphate and 4– BC aerosols. In these, the effect of the range of uncertainty in each factor on the temperature change projected from fuel substitution was examined. Three additional factors that were characteristics of the switch were also considered: 1– the relative efficiency of coal to natural gas power generation, and emissions of 2– sulphur, and 3– black carbon from coal combustion that depend on fuel characteristics, technologies applied, and emission controls. How these factors affect the timing and magnitude of temperature change projected to result from coal-to-gas fuel substitution were investigated. Finally, the effect of gas-for-coal substitution on future climate change in the context of energy consumption and emissions projected by the IPCC in 2000 were evaluated. Analyses of various fuel substitution scenarios, in terms of extent and scheduling, showed the potential range of fuel substitution impacts on the timing and magnitude of projected global temperature change (Hayhoe and others, 2002).

The results aimed to illustrate the balances that determine the effectiveness of fuel switching as a climate-impact mitigation-option. These included the balance between the short-term warming effects of SO_2 reductions and the long-term cooling effects of CO_2 reductions, and the balance between the increases in methane emissions, from natural gas, versus the decrease in emissions from coal mining that would be associated with the switch. The results also highlighted the contribution of BC and SO_2 emissions to the short-term response of climate to fuel switching, and the dependence of the outcome of fuel switching on the implementation pathway followed and the time horizon over which the temperature change is evaluated.

Hayhoe and others (2002) found that for constant electricity production, the substitution of coal with gas could reduce projected global temperature after 25 years, a delay approximately equal to the lifetime of power generation capital stock. The dependence of the delay on several key factors was examined by calculating the sensitivity of results to these factors. Four of the factors, methane emissions from natural gas loss and coal mines, and the radiative forcing associated with sulphate and BC aerosols, had uncertain estimates that the authors considered needed to be better resolved, preventing the effect of fuel switching on temperature from being characterised precisely. Three other factors, the relative efficiency of coal to gas-fired utilities, and controls on sulphur and BC emissions from coal combustion, were considered characteristics of an individual fuel substitution that could be adjusted to give a desired system performance, including effects on climate through emissions. Analysis of the uncertainties and possible characteristics of a coal-to-gas fuel substitution produced the following main findings (Hayhoe and others, 2002):

- uncertainty in methane emissions from coal mining and natural gas loss resulted in a similar range of coal/gas temperature change ratios, suggesting that each uncertainty contributes equally to determining methane emissions from a coal-to-gas switch;
- for the year 2000 emission levels, sulphate aerosol forcing was the dominant uncertainty, producing a range in coal/gas temperature ratio that far exceeded that of BC forcing and methane emissions. Depending on the assumed direct and indirect sulphate aerosol forcing, coal-to-gas substitution would not result in mitigation of temperature increase until anywhere from 0 years (low forcing) to 80 years (high forcing) after continued use;
- in terms of selecting candidate coal-fired power plants to be replaced by natural gas, the sulphur content of the fuel affected the timing of temperature change to the largest degree of any of the factors considered, while a wide range in relative efficiencies of the utilities involved produced the highest coal-to-gas temperature change ratio ($R > 4$) over the long term;
- focusing on reducing BC emissions from the power sector as a primary short-term approach to climate change mitigation may not achieve the desired effect on climate. Emissions controls, or lack thereof, lead to a correlation between SO_2 and BC emissions in coal power plants. Although targeting a high-BC emitting coal power plant for natural gas substitution would result in a decrease in warming due to decreased BC aerosols, such a decrease would, in most instances, be offset by reductions in SO_2 emissions. This would lead to a decrease in the cooling effects of sulphate aerosols that could more than compensate for the reduction in BC emissions;
- overall, the choices that can be made in selecting the facilities to be replaced and the replacement technology to be used were found to have a greater range of effect on the mitigation potential of fuel switching than the range of uncertainties in emission factors and aerosol forcing. This implies that, regardless of the large uncertainties that still exist, selection of facilities for fuel substitution can contribute to climate change mitigation;
- the projected global temperature effects of substituting gas-fired power generation for 10–50% of coal-fired power generation over the century was evaluated in the context of an IPCC baseline scenario. Under which, fuel switching was not projected to contribute to climate change mitigation over time scales less than 5 to 30 years. This time scale depended on the year of implementation since the scenario included varying SO_2 emissions and coal-fired electricity generation over time. Substitution of 10–50% of coal-fired power generation by gas-fired power generation could result in a reduction of the projected global temperature increase from 2000 to 2100 by 0.14°C to 0.68°C. This range of fuel substitution, therefore, could result in the mitigation of 5–25% of projected global temperature rise from 2000 to 2100, regardless of assumed climate sensitivity;
- substitution of gas for coal in the IPCC scenario produced a cooling effect due to reduced emissions of CO_2, CH_4 and BC that is partially mitigated by warming due to decreased SO_2 emissions. The contribution of each gas depends on the time of substitution; fuel substitution in 2050 could result in a much smaller decrease in SO_2 and a slightly smaller decrease in CO_2 than fuel substitution in 2000. The effect is due to the scenario for increasing SO_2 controls and decreasing coal/gas efficiency ratios.

This produced a projected net temperature decrease almost 20 years sooner, and substitution in 2050 as opposed to substitution in 2000;

- analysis of various pathways to achieving a given percentage gas-for-coal substitution showed that the drawbacks of delaying action, in terms of mitigating net temperature change by 2100, may be compensated by accomplishing that action in a short time frame of a few years as compared to a few decades.

Hayhoe and others (2002) concluded that reducing the long-term effect of GHG and aerosols emissions on climate is not the only issue involved in the implementation of fuel switching, or a GHG abatement strategy. The authors consider that, for SO_2 emissions from coal-fired power plants in particular, the immediate effects of SO_2 on local and regional air pollution and acid rain need to be balanced with the regional and global effect of mitigating the risk of a highly uncertain and long-term change in climate. A complete study of the subject matter would include additional issues such as capital cost, availability of resources, technology, policy implementation, regional issues, international trade, and other environmental concerns. Nevertheless, CO_2, CH_4, sulphur and BC emissions appear to present additional design and deployment criteria, in terms of efficiency, fuel choice, emission controls, and selection of facilities to be replaced, that can be selected in order to capture the effects of fuel switching on the radiative forcing of climate.

In 2011, Wigley considered a scenario where a fraction of coal usage is replaced with natural gas over a given time period, and where a percentage of the methane in the gas production process is assumed to leak into the atmosphere. Wigley (2011) extended and updated the analysis of Hayhoe and others (2002) to examine the potential effects of gas leakage on the climate from fracking activities, and on questions arising from uncertainties in leakage rates.

Using reference scenarios and modelling tools, Wigley (2011) summarised his findings to show that the substitution of gas for coal as an energy source results in increased rather than decreased global warming for many decades, to the mid-22nd century for the 10% leakage case. This is in accord with the findings of Hayhoe and others (2002) and Howarth and others (2011) based on Global Warming Potentials (GWP) analysis rather than direct modelling of the climate. Wigley (2011) emphasises that the results are critically sensitive to the assumed leakage rate. When gas replaces coal there is additional warming to 2050 with an assumed leakage rate of 0%, and out to 2140 if the leakage rate is as high as 10%. The analysis shows that warming results from two effects: the reduction in SO_2 emissions that occurs due to reduced coal combustion; and the potentially greater leakage of methane that accompanies new conventional and unconventional gas production, relative to coal. The first effect is in accord with Hayhoe and others (2012). However, the methane effect is in the opposite direction (albeit small). Wigley (2011) considers that this finding is due to the analyses using (more recent information on) gas leakage from coal mines and gas production, with greater leakage from the latter.

Wigley (2011) assumed a linear decrease in coal use in his coal-to-gas scenario from zero in 2010 to 50% reduction in 2050, continuing at 50% after that, while Hayhoe and others (2002), considered linear decreases from zero in 2000 to 10%, 25% and 50% reductions in 2025. If Hayhoe and others (2002) assumed constant reduction percentages after 2025, then the high findings coincide in both scenarios. The temperature differences in the Wigley (2011) analyses between the baseline and coal-to-gas scenarios are small (less than 0.1°C) to at least 2100. The result, however, is that, unless leakage rates for new methane emissions can be kept below 2%, substituting gas for coal is not an effective means for reducing the magnitude of future climate change. This contradicts the findings of Ridley (2011) who considers that the exploitation of shale gas will 'accelerate the decarbonisation of the world economy'. Wigley (2011) considers that 'the key point here is that it is not decarbonisation per se that is the goal, but the attendant reduction of climate change'. Wigley (2011) iterates that in the shorter-term effects are in the opposite direction. Wigley (2011) concludes that given the small climate differences between the baseline and the coal-to-gas scenarios, decisions regarding further exploitation of gas reserves should be based on resource availability (both gas and water), the economics of extraction, and environmental impacts unrelated to climate change.

Newell and Raimi (2014) studied the implications of shale gas development for climate change. They consider that the lower natural gas prices resulting from shale gas exploration and extraction have two main effects: increasing overall energy consumption and encouraging coal to gas, nuclear or renewable substitution for electricity production. Newell and Raimi (2014) examined current data available and analysed modelling projections to understand how these two dynamics affect GHG emissions. They found that most data indicates that natural gas as a substitute for coal in electricity production decreases overall GHG and other emissions, depending on the electricity mix displaced. Modelling suggests that in the absence of substantial policy changes, increased natural gas production slightly increases overall energy use, more substantially, it encourages fuel switching and that the combined effect slightly alters economy wide GHG emissions. Whether the net effect is a slight decrease or increase depends on modelling assumptions including upstream methane emissions. The authors main conclusions were that natural gas can help reduce GHG emissions, but in the absence of targeted climate policy measures, it will not substantially change the course of global GHG concentrations. Abundant natural gas however, can help reduce the costs of achieving GHG reduction goals. Newell and Raimi (2014) concluded that, in the USA, if natural gas continues to displace more coal in the power generating industry, the result is likely to be a net benefit for the climate in the long term. However, high levels of methane emissions can reduce the benefit and therefore understanding of methane emissions from natural gas systems, needs improvement. Newell and Raimi (2014) consider that additional research is necessary. Key areas include methane emissions from natural gas systems and other sources; the emissions profiles of natural gas versus electricity and oil-based heating systems; the GHG implications of changes in international trade patterns due to shale gas growth; and the likely magnitude of substitution of natural gas for coal versus zero-carbon electricity, both in the USA and internationally.

Assessment of the full impact of abundant gas on climate change according to McJeon and others (2014) requires an integrated approach to the global energy–economy–climate systems. However, the literature is limited in either geographic scope or coverage of GHGs. Five integrated assessment models (IAMs), including BAEGEM13, GCAM14, MESSAGE15, REMIND16 and WITCH17, were employed in a study by McJeon and others (2014) to project emission scenarios for global and regional assessments. The IAMs belong to a class of models designed to assess the implications of changes in the global energy system on climate forcing. A climate forcing is any influence on climate that originates from outside the climate system itself. The climate system includes the oceans, land surface, cryosphere, biosphere and atmosphere. Examples of external climate forcing include surface reflectivity (albedo), human induced changes in GHGs and atmospheric aerosols (such as volcanic sulphates and industrial output). McJeon and others (2014) show that market-driven increases in global supplies of unconventional natural gas do not discernibly reduce the trajectory of GHG emissions or climate forcing. The results, based on simulations from the five IAMs, listed above, of energy–economy–climate systems independently forced by an abundant gas scenario, project large additional natural gas consumption of up to +170% by 2050. The impact on CO_2 emissions, however, was found to be much smaller (from –2 to+11%), and a majority of the models reported a small increase in climate forcing (from –0.3% to +7%) associated with the increased use of abundant gas. McJeon and others (2014) concluded that the results show that although market penetration of globally abundant gas may substantially change the future energy system, it is not necessarily an effective substitute for climate-change mitigation policy.

Bradbury and others (2013) studied what is known about methane emissions from the natural gas sector, what progress has been made to reduce those emissions, and what more can be done. The authors found that upstream emissions of greenhouse gases, particularly methane, contribute significantly to the climate impacts of USA natural gas production. Although significant uncertainties continue regarding the exact level of methane emissions throughout the USA natural gas life cycle, studies in general agree that life cycle GHG emissions from natural gas are lower than coal, particularly when considering a longer, 100-year time horizon. Nevertheless, policy action and investment can and should be used in order to reduce upstream methane emissions from natural gas systems. Bradbury and others (2013) concluded that uncertainty should not result in delayed action, as there are cost-effective opportunities to reduce upstream methane emissions significantly.

According to Howarth and others (2012), global warming potentials provide a relatively simple approach for comparing the influence of methane and CO_2 on climate change. In the national GHG inventory, the US EPA uses a global warming potential of 21 over an integrated 100-year time frame, based on the 1995 report from the Intergovernmental Panel on Climate Change (IPCC) and the Kyoto protocol. However, the latest IPCC Assessment (in 2007) used a value of 25, while more recent research that considers the interaction of methane with other radiative active materials in the atmosphere suggests a mean value for the global warming potential of 33 for the 100-year integrated time frame. Using this value and the methane emission estimates based on US EPA data, Howarth and others (2012) calculated that methane contributes 19% of the entire GHG inventory of the USA, including CO_2 and all other gases from human activities. The methane from natural gas systems alone contributes over 7% of the entire GHG inventory of the USA, noting that the variation in the global warming potential estimates between 21 and 33 is substantially less than the variation among the methane emission estimates. Mackenzie (2012) presented the natural gas systems' methane emission sources in Figure 27.

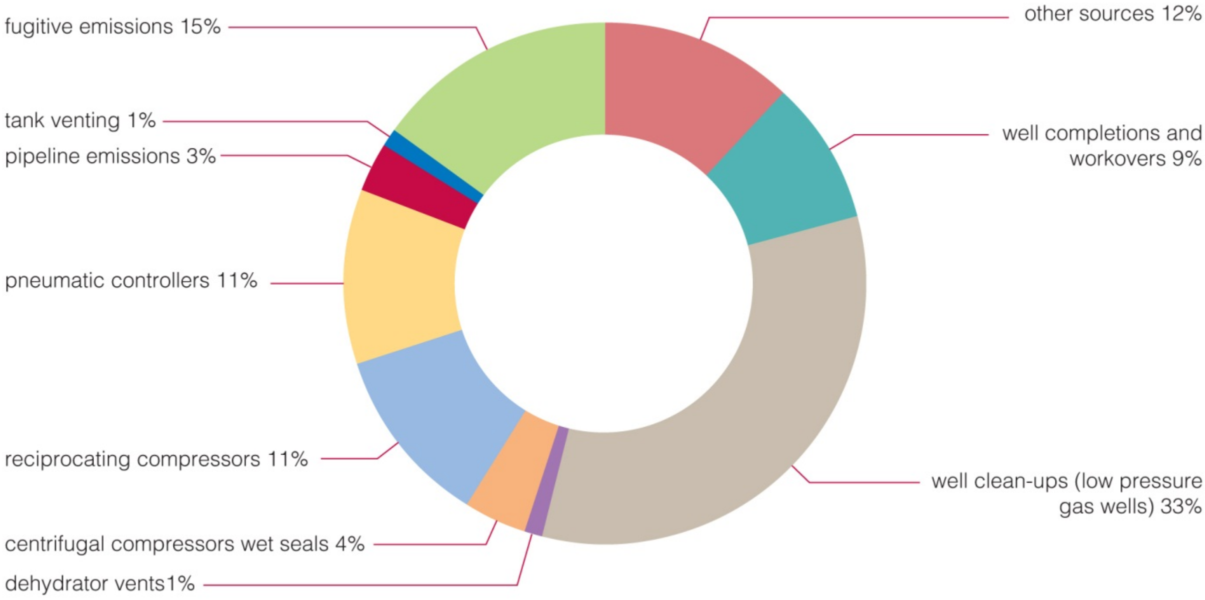


Figure 27 Natural gas system methane emission sources (Mackenzie, 2012)

The global warming potentials of 21, 25 and 33 are for an integrated 100-year time frame following emission of methane to the atmosphere. The choice of 100 years is arbitrary, and the global warming potentials at longer or shorter time scales may also be considered. To date, estimates have typically been provided at time scales of 20 years and 500 years, in addition to the 100-year time frame. For the 20-year time frame, using a mean estimate of 105 for the global warming potential, Howarth and others (2012) calculated that methane contributes 44% of the entire GHG inventory of the USA, including CO_2 and all other gases from human activities. Hence while methane is only causing about 1/5 of the century-scale warming due to USA emissions, it is responsible for nearly half the warming impact of current USA emissions over the next 20 years. At this time scale, the methane emissions from natural gas systems contribute 17% of the entire GHG inventory of the US, for gases from all sources. Howarth and others (2012) consider that the estimates may be low, and that the gradual replacement of conventional natural gas by shale gas is predicted to increase these methane fluxes by 40% to 60% or more.

In 2012, Alvarez and others published a document stating that greater focus is needed on methane leakage from natural gas infrastructure. The authors consider that comparing the climate implications of methane and CO_2 emissions is complicated because of the much shorter atmospheric lifetime of methane relative to CO_2. According to Alvarez and others (2012), on a molar basis, ammonia produces 37 times more radiative forcing than CO_2. However, because methane is oxidised to CO_2 with an effective lifetime of 12 years, the integrated, or cumulative, radiative forcing from equi-molar releases of CO_2 and methane eventually converge toward the same value. Determining whether a unit emission of methane is more detrimental for the climate than a unit of CO_2, depends on the time frame considered. As accelerated rates of warming mean ecosystems and humans have less time to adapt, increased methane emissions due to substitution of natural gas for coal may produce undesirable climate outcomes in the near term.

Alvarez and others (2012) consider that much work is needed to determine actual methane emissions from the natural gas infrastructure with certainty and to characterise the site-to-site variability in emissions accurately. For example, analysis of reported routine emissions for over 250 well sites with no compressor engines (in Barnett Shale gas well sites in Fort Worth, Texas, USA) in 2010 revealed a highly skewed distribution of emissions, with 10% of well sites accounting for nearly 70% of emissions. Nonetheless, based on actual, evidential data – although currently limited – Alvarez and others (2012) consider it likely that leakage at individual natural gas well sites (if high enough, when combined with leakage from downstream operations) can make the total leakage exceed the 3.2% threshold beyond which gas becomes more detrimental for the climate than coal, for at least some period of time.

Pickering (2012) discussed coal-to-gas switching phenomenon in the USA with reference to:

- displacement of coal-fired power plant with gas-fired generation due to short-term fuel price competition and;
- retirement of coal-fired capacity and replacement with natural gas fired plant.

The main driver behind coal-to-gas switching is the relative cost of natural gas versus coal. Historically, natural gas has been more expensive than coal resulting in greater utilisation of coal in power generation compared to gas. However, in recent years, due to the high demand for coal, coal prices increased. Meanwhile, in the USA, the exploration and extraction of shale gas resulted in reducing the price of domestic natural gas, making it competitive with coal. Figure 28 shows the spread of coal-fired power plant capacity in the USA.

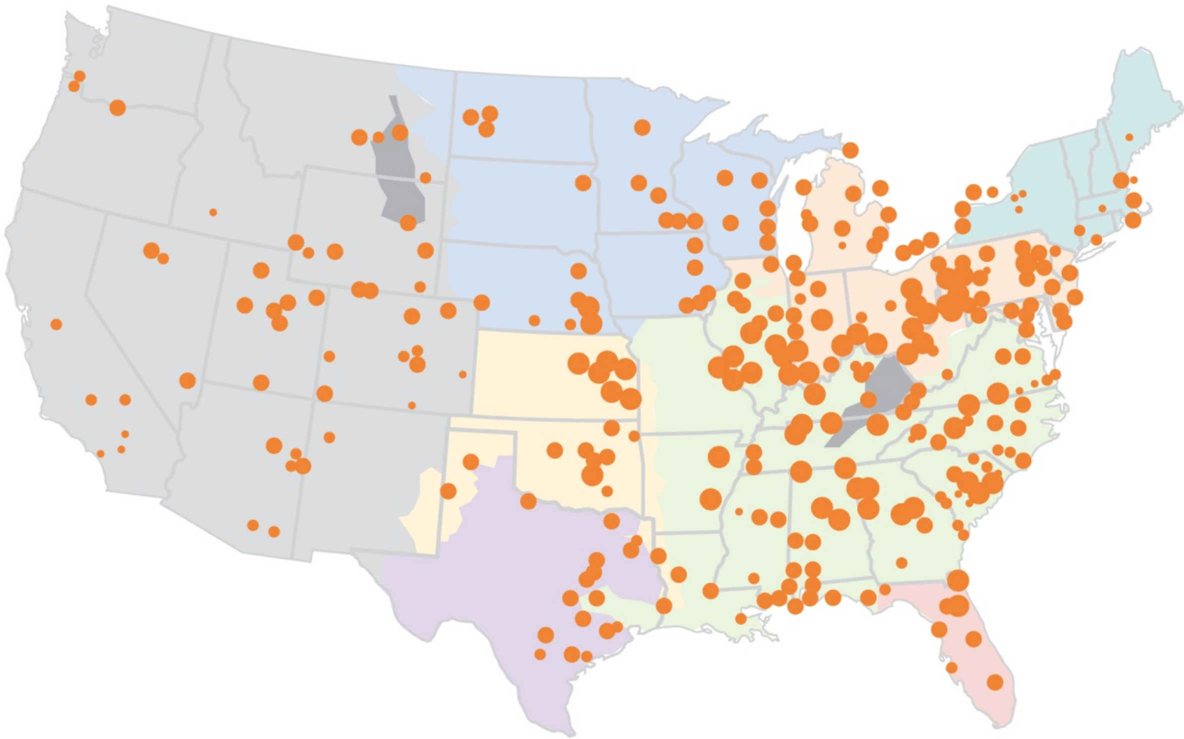


Figure 28 USA coal-fired power plants (Pickering, 2012)

According to Pickering (2012), while coal and natural gas prices converged on a national level in the USA in 2012, regional differences in coal/gas pricing combined with the regional distribution of coal-fired plants resulted in greater impact of coal-to-gas competition in some regions of the country. Pickering (2012) considered that it is important to note that many of the coal-fired plants reducing output due to relatively low natural gas prices are those scheduled for retirement due, in most cases, to age and inefficiency. This means that coal-to-gas switching will continue even though short-term substitution based solely on fuel prices should decrease. In 2012, Pickering projected that 48 GW of coal-fired capacity in the USA would be in line for retirement between 2011 and 2017 (*see* Figure 29).

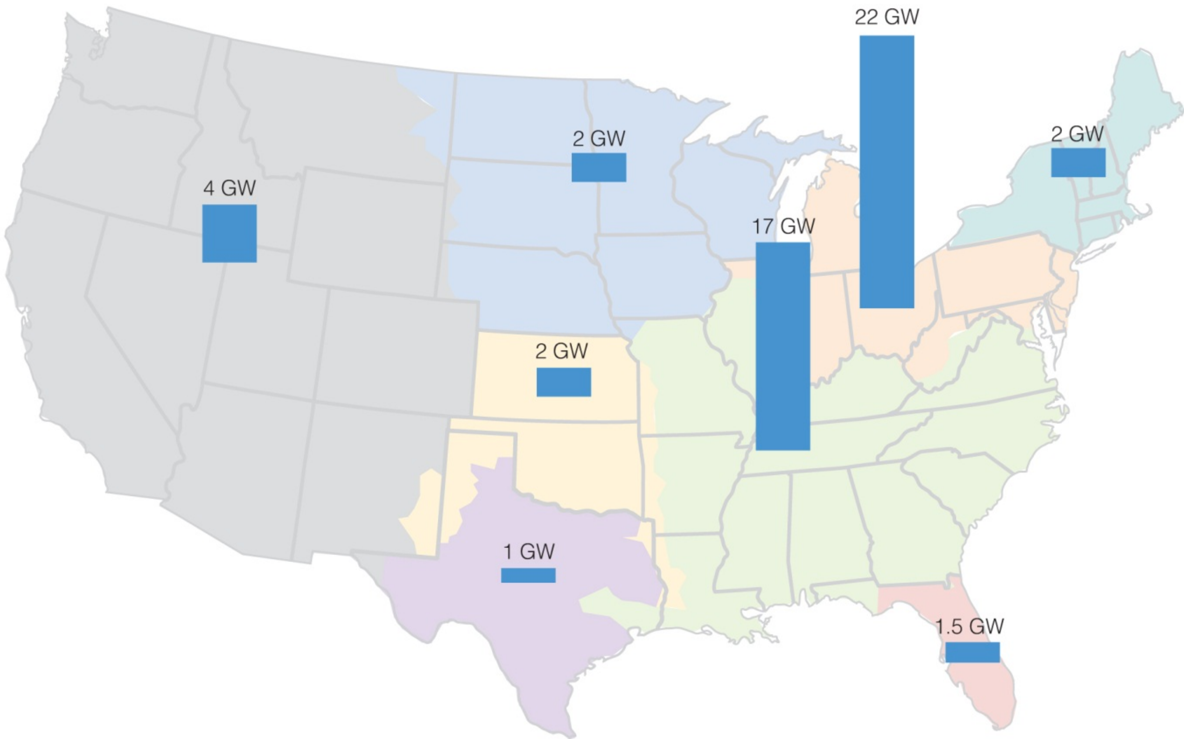


Figure 29 Projected coal retirements from 2011 by the North American Electric Reliability Corporation (NERC) (GW) (Pickering, 2012)

Coal provided 18% of primary energy consumption in the USA in 2012. However, coal use has declined over the past several years. Additional decline is projected for the principal use of coal in the USA, electric power generation. The EIA estimates that USA coal-fired electric power capacity will decline by 60 GW in 2018, compared to 2011. The decline reflects a combination of market forces and the cost of compliance with regulatory requirements applicable to coal-fired electric power plants (Carter, 2014).

In a report published by the Institute for Energy Research (USA), Bezdek and Clemente (2014) consider that, in the USA, 'policy makers, regulators and electric utilities should institute an immediate moratorium on the premature closure of coal power plants and should reverse planned closures where possible'. According to Bezdek and Clemente (2014), USA government policies that drive over-dependence on natural gas to replace base load, reliable, affordable and abundant coal-based power generation not only put the USA electricity supply at risk but also divert the gas from households and industries and subsequently make it more expensive, thus impacting economic growth.

Increased demand for gas for power generation in the USA driven by the regulators push to retire older coal-fired plants and replace them with gas-fired units could result in further climate implications due to the increased methane flux. Development of shale gas in other parts of the world could lead to a similar situation. However, that is not the current status as Asia, Europe and other regions are increasing their utilisation of coal due to coal availability and price compared to gas.

In 2011, the National Petroleum Council (NPC) (USA) examined a broad range of energy supply, demand, environmental, and technology outlooks in the USA through 2050. The study addressed issues relating to public health, safety, and environmental risks associated with natural gas and oil production and delivery practices, as well as opportunities for natural gas to reduce emissions from energy use. The NPC considers that natural gas can reduce the USA GHG and other air emissions in the near term, especially if methane emissions from gas production and delivery are reduced. The NPC recognises that the power sector is the area where the biggest reduction opportunities exist, but also addresses the industrial, commercial, and residential sectors. In recent years, favourable gas prices combined with environmental regulations have resulted in displacing some coal-fired power generation. The trend is likely to continue with plans to retire older, less efficient coal-fired power plants. In the long term, the NPC recognises that if greater reductions in GHG emissions are desired, all fossil-fuelled power generation, including natural gas must be curtailed, by putting a price on carbon emissions or utilising technologies such as carbon capture and storage.

According to the NPC (2011) and based on EPA estimates of methane emissions during production and delivery, the life-cycle emissions for natural gas are ~35% lower than coal on a heat-content basis. In terms of the production of electricity, for efficiencies typical of coal- and natural gas-fired plants, natural gas has about 50–60% lower GHG emissions than those of a coal-fired plant (*see* Figure 30 – Life cycle GHG emissions for natural gas and coal plant (NPC, 2011)). With regard to reducing methane emissions from natural gas systems, the NPC (2011) recommended that industry-government partnerships be used to promote technologies, protocols, and practices to measure, estimate, report, and reduce emissions of methane in all cycles of production and delivery. Also, ensuring greater adoption of these technologies and practices within all sectors of the natural gas industry, with a focus on significantly reducing methane emissions while maintaining high safety and reliability standards.

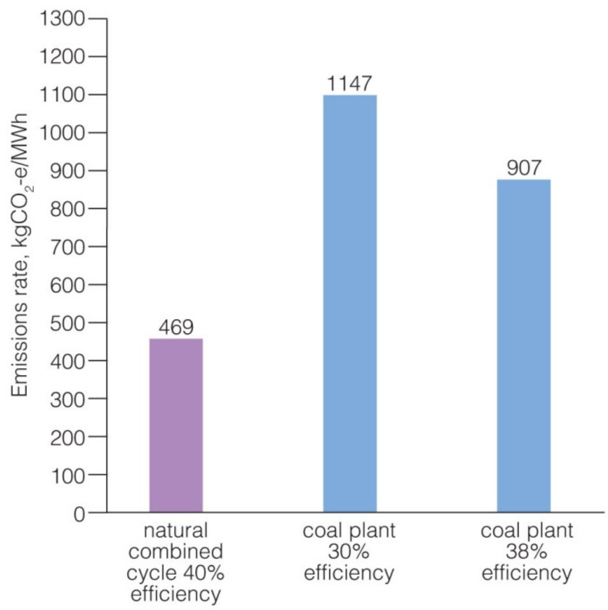


Figure 30 Life cycle GHG emissions for natural gas and coal plant (NPC, 2011)

In 2013, the Center for Climate and Energy Solutions (C2ES) published a report on leveraging natural gas to reduce GHG emissions including an examination of the implications of substituting coal with gas-fired power plants. Although the C2ES note that it is essential to maintain fuel mix diversity in the power sector, the following conclusions were drawn from the report (C2ES, 2013):

- the expanded use of natural gas, as a replacement for coal and petroleum, can contribute towards reducing total GHG emissions in the near- to mid-term;
- however, substitution of natural gas for other fossil fuels cannot be the sole basis for long-term USA efforts to address climate change because natural gas is a fossil fuel and its combustion emits GHGs. Zero-emission sources of energy, such as wind, nuclear and solar, are critical, as are the use of CCS technologies at fossil fuel plants and continued improvements in energy efficiency and;
- whilst substituting natural gas for other fossil fuels, direct releases of methane into the atmosphere *must* be minimised. It is important to understand and measure, accurately, GHG emissions from natural gas production and use in order to achieve emissions reductions along the entire natural gas value chain.

In May 2013, Climate Central published a review on climate benefits of natural gas uses versus coal. Larson (2013) considers knowing how much methane is leaking from the natural gas system essential to determining the potential climate benefits of natural gas use. The extent of reducing the global warming impact of methane depends largely on the following factors (Larson, 2013):

- methane leakage rate from the natural gas system;
- time passage after switching from coal to gas, as the potency of methane as a GHG gas is 102 times that of CO_2 (on a pound-for-pound basis) when first released into the atmosphere and decays to 72 times CO_2 over 20 years and to 25 times CO_2 over 100 years and;
- the rate at which coal-based power generation is replaced with gas.

Climate Central considers that the ongoing shift from coal to gas in power generation in the USA is unlikely to provide the 50% reduction in GHG emissions typically attributed to it, over the next three to four decades, unless, gas leakage is maintained at the lowest estimated rates (1–1.5%) and the coal replacement rate is maintained at recent high levels (>5%) per year (*see* Figure 31).

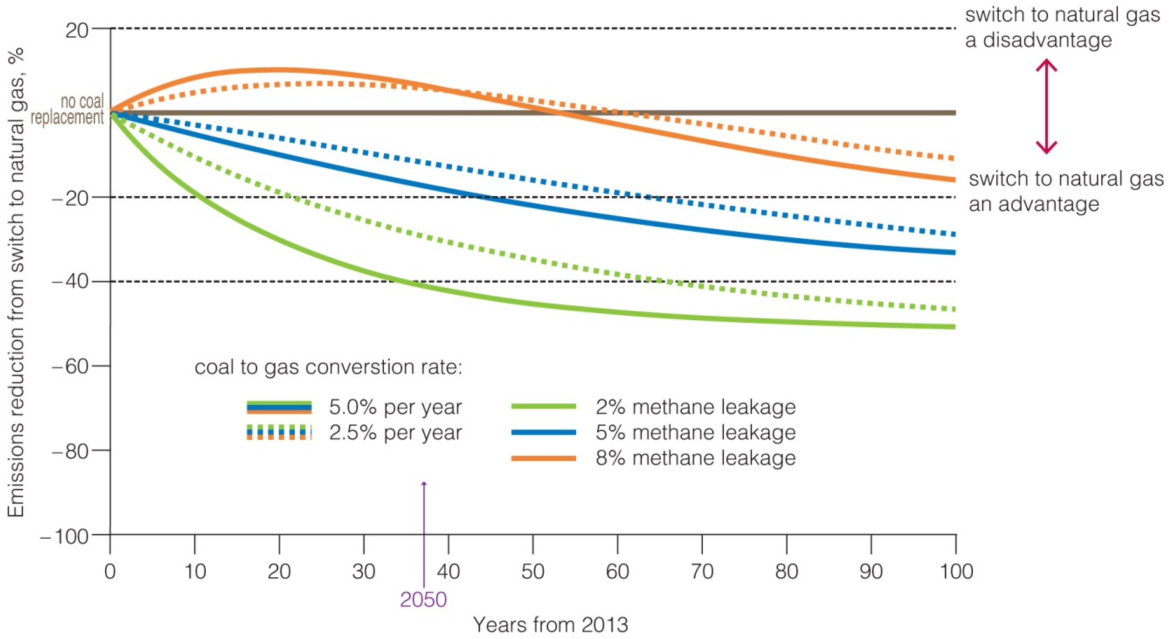


Figure 31 Effect of switching from natural gas to coal fired power generation (Larson, 2013)

To visualise the benefits of converting power generation from coal to natural gas (for different assumptions of methane leakage rates and coal to gas conversion rates while also considering the potency of methane over time), Climate Central developed an interactive graphic tool incorporating all three factors (*see* www.climatecentral.org) (Larson, 2013).

According to Hirst and others (2013), ***if*** well managed and regulated to minimise methane emissions and other more localised impacts, shale gas can *potentially* offer mitigation opportunities over the next couple of decades. Without such measures, shale gas may not offer significant advantages over coal in terms of climate change. Hirst and others (2013) note that government incentives for and investments in shale gas production and gas generation may result in significant carbon emissions for many decades to come. They could thus affect innovation, development and deployment of lower-carbon options, such as nuclear power, renewables and energy efficiency.

A life cycle analysis of natural gas extraction and power generation was the subject of a US DOE NETL review by Skone and others (2014). The life cycle GHG inventory used in the analysis also developed upstream (from extraction to delivery to a power plant) emissions for delivered energy feedstock. These included seven different USA sources of natural gas, of which four were unconventional gas, and two types of coal, and then combined them both into domestic mixes. The authors found that although natural gas has lower GHG emissions than coal on a delivered power basis, the extraction and delivery of natural gas has a meaningful contribution to US GHG emissions, that is, 25% methane emissions and 2.2% of GHG emissions (EPA, 2013a). For natural gas that is consumed by power plants, 92% of the natural gas extracted at the well is delivered to the plant. An 8% share that is not delivered to a power plant is vented (either intentionally or unintentionally) as methane emissions, flared in environmental control equipment, or used as fuel in process heaters, compressors, and other equipment. For the delivery of 1,000 kg of natural gas to a power plant, 12.5 kg of methane is released to the atmosphere, 30.3 kg is flared to carbon dioxide (CO_2) via environmental control equipment, and 45.6 kg is combusted in process equipment. When these mass flows are converted to a per cent basis, methane emissions to air represent a 1.1% loss of natural gas extracted, methane flaring represents a 2.8% loss of natural gas extracted, and methane combustion in equipment represents a 4.2% loss of natural gas extracted. These percentages are on the basis of extracted natural gas. Converting to a denominator of delivered natural gas gives a methane leakage rate of 1.2%. The analysis highlighted that results are sensitive to and impacted by the uncertainty of a few key parameters. These included the use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes, such as well completion and workovers; and the lifetime production rates of wells, which determine the denominator over which lifetime emissions are calculated (Skone and others, 2014).

Skone and others (2014) consider that when accounting for a wide range of performance variability across varying assumptions of climate impact timing, in the USA, natural gas-fired base-load power production has life cycle greenhouse gas (GHG) emissions 35 to 66% lower than those for coal-fired base-load electricity. The lower emissions for natural gas are attributed primarily to the differences in average power plant efficiencies in the USA (46% efficiency for the natural gas power fleet versus 33% for the coal power fleet) and a higher carbon content per unit of energy for coal in comparison to natural gas. According to Skone and others (2014), natural gas fired electricity has 57% lower GHG emissions than coal per delivered MWh using current technology when compared with a 100-year GWP using unconventional natural gas from tight gas, shale, and coal beds.

8 Uncertainties

Natural gas emits about half as much CO_2 as coal at the point of combustion. However, the issue is more complicated from a life cycle perspective. According to numerous studies, the general consensus is that there is considerable uncertainty about the scale of upstream methane emissions from natural gas systems due to variations between production basins and a scarcity of recent, direct emissions measurements from several key processes. Ultimately, the question of whether or not natural gas has a smaller climate impact than coal depends on the life cycle of methane leakage rates, in addition to other factors that include subjective policy considerations.

In the USA, the EPA recently estimated methane leaks in the natural gas system at 1.5%. Such a leakage rate in the natural gas systems would result in achieving an immediate ~50% reduction in GHG emissions, if gas substitutes coal at an individual power plant level. However, according to Larson (2013) and many others, the estimate used by the EPA contains significant uncertainty, and like all estimates available in the peer-reviewed literature today, lacks sufficient, actual, real-world measurements to guide decision-making at the national level.

Bradbury and others (2013) consider that while uncertainties remain regarding exact methane leakage rates, the weight of evidence suggests that significant leakage occurs during every life cycle stage of USA natural gas systems, not just the production stage (*see* Figure 32).

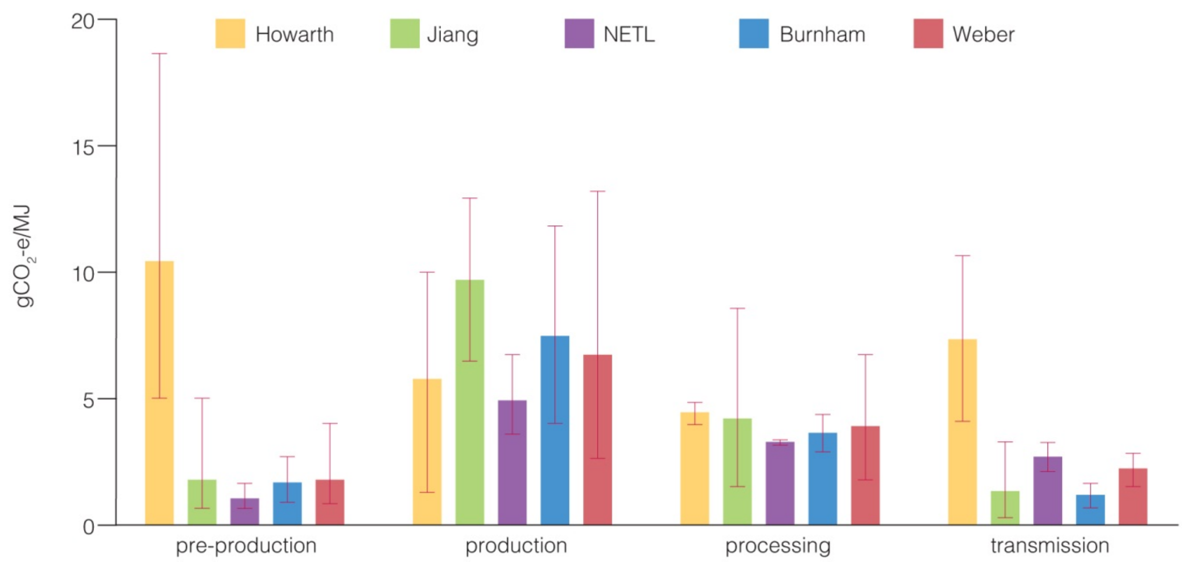
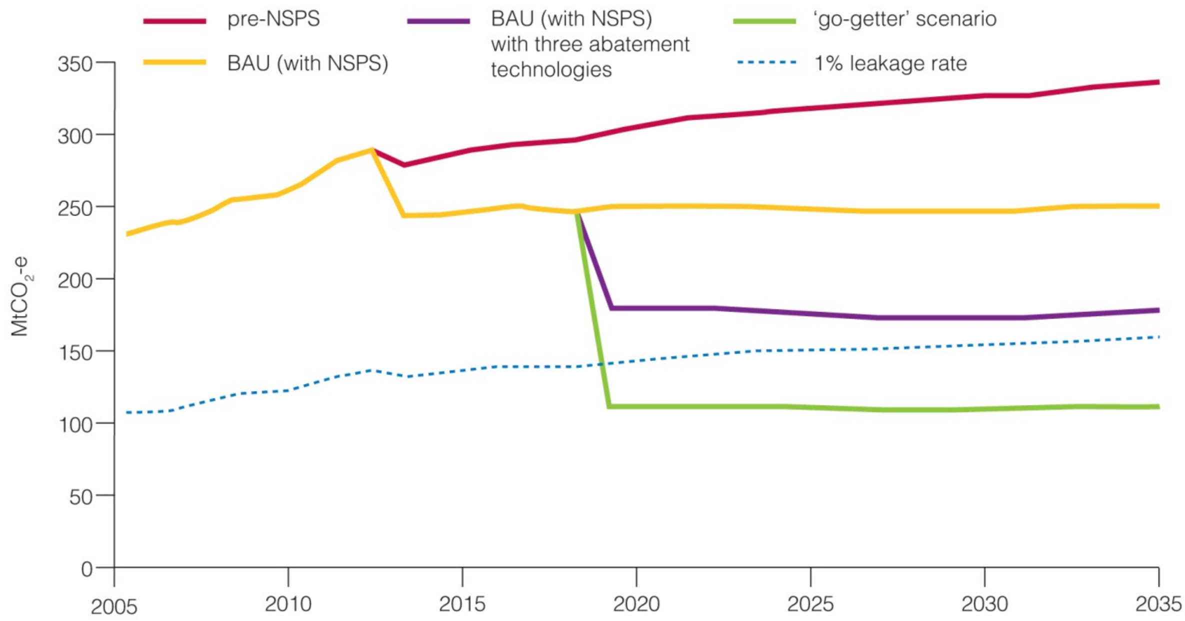


Figure 32 Upstream GHG emissions from shale gas, by life cycle stage (Bradbury and others, 2013)

However, Bradbury and others (2013) consider that the implementation of three technologies, that capture or avoid fugitive methane emissions, could reduce up to 30% of the upstream methane emissions across all natural gas systems cost-effectively (*see* Figure 33) (New Source Performance Standards (NSPS) and business as usual (BUI)). The technologies include:

- the use of plunger lift systems at new and existing wells during liquids unloading operations;
- fugitive methane leak monitoring and repair at new and existing well sites, processing plants, and compressor stations and;
- replacing existing high-bleed pneumatic devices with low-bleed equivalents throughout natural gas systems.



Notes: Potential for additional upstream methane emissions reductions for all natural gas systems based on implementation of a hypothetical rule in 2019 requiring plunger lift systems, leak detection and repair, and replacing existing high-bleed pneumatic devices with low-bleed equivalents (purple line); or a rule requiring those technologies and five additional abatement measures (green line). The light blue dashed line shows the total amount of GHG emissions ($MtCO_2$-e) that would result from 1 per cent fugitive methane emissions relative to total dry gas production in each year, plus estimated annual CO_2.

Figure 33 Projections of GHG emissions from all natural gas systems after additional abatement (Bradbury and others, 2013)

Bradbury and others (2013) estimate that these three steps would bring down the total life cycle leakage rate across all natural gas systems to just above 1% of total production. Through the adoption of five additional abatement measures that each address smaller emissions sources, the 1% goal would be readily achieved.

In an expert survey for Resources for the Future, Krupnick and others (2013) identified that despite uncertainties, methane emissions are, as a consensus, an environmental risk that should be addressed through government and industry actions.

According to Larson (2013), there are large differences among published estimates of methane leakage from the natural gas supply system, from <1% of methane production to as much as 8%. At the basin level, methane leakage rates as high as 17% have been reported. The EPA 2012 annual GHG emissions inventory estimate was 2.2%. Its 2013 inventory estimate made a large adjustment that reduced the estimate to 1.5%. The degree of methane leakage is uncertain, but it is likely to be reduced in the future since it also represents lost profits for gas companies. Determining methane leakage is complicated by various uncertainties such as (Larson, 2013):

- large variability and uncertainty in industry practices at wellheads, including:
  - whether the methane that accompanies flowback of hydraulic fracking fluid during completion of shale gas wells is captured for sale, flared, or vented at the wellhead. Industry practices appear to vary widely and;
  - in liquids unloading, which must be done multiple times per year at most conventional gas wells and also at some shale gas wells, gas entrained with the liquids may be vented to the atmosphere. There have been relatively few measurements of vented gas volumes, and estimating an average amount of methane emitted per unloading is difficult due to intrinsic variations from well to well.
- lack of sufficient production experience with shale gas wells:
  - there are orders of magnitude in variability of estimates of how much gas will ultimately be recovered from any given shale well. This makes it difficult to define an average lifetime production volume per well, which introduces uncertainty in estimating the percentage of gas leaked over the life of an average well and;
  - the frequency with which a shale gas well must be re-fractured to maintain gas flow. This process, known as a well workover, can result in methane emissions. The quantity of emissions per workover is an additional uncertainty, as it depends on how workover gas flow is handled.
- the leak integrity of the large and diverse gas distribution infrastructure:
  - leakage measurements are challenging due to the large extent of the distribution system, including more than a million miles of distribution mains, more than 60 million service line connections, and thousands of metering and regulating stations operating under varying gas pressures and other conditions;
  - recent measurements of elevated methane concentrations, in the air above streets in different states in the USA, strongly suggest distribution system leakages. Additional measurements are needed to estimate leakage rates based on such measurements.

The NPC (2011) also recognises a very high degree of uncertainty around estimates of methane emissions and, therefore reaffirms that better data are needed while efforts continue to reduce such emissions. Uncertainty was also discussed in detail by George and others (2011) in a working document on the life-cycle emissions of natural gas and coal in the power sector. Life-cycle assessment of GHG emissions from gas and coal fired power generation is the subject of many reviews including ICF Consulting Canada (2012), George and others (2011), Hughes (2011), PACE (2009) and Jaramillo and others (2007).

Smith and others (2011) estimated a global uncertainty in 2005 SO_2 emissions of ±11%. Uncertainty in more recent emissions (2010/2011) is likely to be larger due to the greater contribution of particularly uncertain emissions from developing countries and international shipping. Reducing this uncertainty will require more robust estimates of the sulphur content of coal and heavy oils (particularly for shipping) and more detailed tracking of the operation of emission controls.

Uncertainties have been noted throughout this review and so remain a topical issue with many urging greater investigation, understanding and measurements of actual methane leakage with calls for immediate application of appropriate technology, where and when possible, to minimise and control the leakage.

9 Conclusions

Methane (CH_4) is a hydrocarbon and the primary component of natural gas. It is more potent than carbon dioxide (CO_2) as a greenhouse gas (GHG), and therefore is a significant contributor to climate change, especially in the near term (10–20 years). Approximately 37% of methane emissions come from natural sources such as wetlands, ocean degassing, and volcanoes. However, human activities account for most methane emissions. Those activities include methane emitted during the production and transportation of coal, natural gas and oil. Livestock and other agricultural practices are contributors to methane emissions, which is also emitted from the decay of organic waste in municipal solid waste landfills and some wastewater treatment systems. Methane is the second most abundant GHG after CO_2 and accounts for 14% of global GHG emissions. Though methane is emitted into the atmosphere in smaller quantities than CO_2, its global warming potential (that is, its ability to trap heat in the atmosphere) is ~25 times greater. Consequently, methane emissions are reported to contribute more than a third of current (2014) anthropogenic warming.

Coalbed methane (CBM) is found in coal seams. It can be extracted through wells drilled directly into these seams. Following extraction, CBM can be provided to residential and industrial customers through natural gas pipelines or exported via liquefied natural gas (LNG) terminals. CBM is being produced in Australia, the UK and the USA with ongoing development projects in China and India among many other countries. Spain, France, Poland, Australia, Canada, the People's Republic of China, the UK, Germany, Zimbabwe, and Russia are a few of the countries that have undertaken projects after initial success in the USA in the 1990s. One of the concerns in a CBM well is that water is produced in large volumes, especially in the early stages of production. The water must be disposed of safely in order to avoid contamination. Some views consider production of methane from coal beds actually beneficial as it reduces methane emissions to the atmosphere by removing the gas that is otherwise released during coal mining. Others consider the effects similar to those caused by hydraulic fracturing, also known as 'fracking'. Methane recovered from working mines is usually referred to as coalmine methane (CMM). Drivers for CMM recovery include mine safety and mitigation of significant volumes of methane emissions resulting from coal mining activities. CMM can also be used for energy production.

Recently, active shale gas development by hydraulic fracturing, has triggered divisive debate over the near-, medium- and long-term environmental implications of using these resources. Concerns include air quality, water resources, seismic events as well as community impacts. Concerns regarding the climate change implications of shale gas development are in a significant part due to uncertainty about emissions of methane. Climate Central has gone so far to say: 'extensive review of publicly available studies finds that a pervasive lack of measurements make it nearly impossible to know with confidence what the average methane leak rate is (in this case for the USA) as a whole. More measurements, more reliable data and better understanding of industry practices are needed'. Potential water contamination is another major issue currently under scrutiny resulting from fracking activities.

Efforts to estimate the relative contribution to climate change of natural gas as an energy source compared to coal have included life cycle systems analyses that incorporate all emissions from exploration through end use combustion. Due to the greater potency of methane as a greenhouse gas compared to carbon dioxide, methane emissions during natural gas production and transport may offset a carbon dioxide saving of gas over coal at the combustion point. Numerous recent studies have concluded that a key element of calculating the emissions from shale gas development is better estimates, and where possible measurement, of the volumes of methane lost to the atmosphere during well completions and production activities. Efforts are ongoing to characterise in greater accuracy exactly how much methane is lost across the entire natural gas value chain. It seems that if this is not achieved, and in good time, the disparity in opinion and lack of actual and clear data will continue to result in extreme opposition/reaction to hydraulic fracturing for natural shale gas in many parts of the world.

Commercial exploitation/production of shale gas in the next few years in the EU seems unlikely, due to not only public opposition, but also economic reasons. As such, a short-term reduction in natural gas prices is not forecast, and the outlook appears to be similar in the long term. Nevertheless, natural gas is expected to become more competitive compared with other fossil fuels especially during the transition towards greater use of renewable energy sources. In contrast, worldwide shale gas production, particularly in the USA, is already influencing the relative prices of fuels in Europe. Global shale gas production basically increases the supply of the other fossil fuels and thereby tends to keep prices relatively low. To date, it has mainly resulted in reduced coal prices, as the USA replaces coal with gas on a large scale and exports some of the coal to Europe. However, there is controversy over USA coal exports to Asia. Nevertheless, the magnitude and direction of future price effects remain uncertain.

In the USA, where shale gas exploration and production is currently underway, policy actions are needed to achieve cost-effective methane reduction opportunities. Substituting coal with gas for power generation is already underway, and is expected to continue. However, natural gas markets and related regulatory structures in the USA are not well configured to ensure the best economic or environmental outcome of natural gas utilisation. Ultimately, the question of whether or not gas has a lower climate impact than coal depends on the life cycle methane leakage rates, plus other factors that include subjective policy considerations.

Research shows that in depth risk assessment must be carried out prior to any exploration work. Monitoring should be undertaken before, during and after shale gas operations. Methane as well as other contaminants in groundwater should be monitored, as well as potential leakages of methane as well as other gases into the atmosphere. The geology of each site should be characterised and faults identified. Monitoring data should be submitted to the regulators to manage potential hazards, inform local planning processes and address wider concerns. Monitoring of any potential leaks of methane could provide data to assess the carbon footprint of shale gas extraction.

Today, there is considerable not only governmental, industrial, academic and public but also extensive media attention focussing on the question of whether gas is ‘better’, ie less environmentally detrimental, than coal from a climate perspective. Estimates of methane emissions from shale gas production and use are to put it mildly, controversial. Based on the information reviewed in this report, it seems that proponents of natural gas claim it as a climate-friendly fossil fuel as it produces less GHG emissions in total compared to coal or oil. Such proponents agree, however, that greater understanding, measurement and control of fugitive methane emissions throughout the natural gas infrastructure is required to minimise these emissions and their impact on climate change. However, opponents to natural gas exploration, production and utilisation, and based on life cycle analysis of GHG emissions (combining emissions associated with extraction, distribution, combustion, methane and CO_2 releases) consider that in the power generating sector, gas produced by hydraulic fracturing can have the same impact on climate change and therefore the environment as coal, especially in the shorter-term. This leads to the conclusion that fugitive methane emissions (especially from fracking for shale gas) have similar climate implications (mainly in the near-term) to coal utilisation with regard to emissions and may have a greater impact on water resources. There is no disputing that switching from coal to gas for power generation will result in reduced CO_2 and other emissions. However, most of the climate benefit from the reduced carbon may be offset by either, methane leaks and releases from expanding natural gas systems (unless dealt with appropriately and quickly), or, albeit to a far lesser extent, reductions of sulphates from coal-fired facilities which can provide a cooling effect in the atmosphere.

In summary, the impact of substituting coal with gas in power generation on total emissions is considered by most as beneficial. However, recent and ongoing studies show that fugitive methane emissions from gas exploration, extraction, transmission and distribution make the benefits of such substitution, questionable, especially so in the short term. In reality, current opinion is leaning towards the acceptance that fugitive methane emissions reduce the net climate benefits of using lower-carbon natural gas as a substitute for coal for electricity generation, especially in the near term. In addition, security of supply and the use of reliable, available and affordable fuel mix will result in coal-based power generation continuing to play a major role, albeit a smaller one, in providing electricity throughout the world. All parties advocate the phasing out of fossil fuels for power generation altogether over the next few decades and switching to other forms of energy sources and/or utilising zero-emissions technologies. However, in the meantime coal and gas will continue to play major roles in providing electricity throughout the world.

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