Climate impact of potential shale gas production in the EU

Final Report

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Disclaimer

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Executive Summary

As readily accessible oil and gas reserves are becoming progressively limited the energy supply industry is increasingly turning to unconventional reserves which were previously too complex or too expensive to extract. In particular there has been a growing interest in Europe in the exploitation of gas reserves trapped within shale rock. This is commonly referred to as ‘shale gas’.

As with any drilling and extraction process shale gas extraction may bring environmental and health risks which need to be understood and addressed. In particular the potential contribution of shale gas production to greenhouse gas (GHG) emissions is a key area of interest. These impacts are the subject of this report. The report has been commissioned by DG Climate Action of the European Commission and delivered by AEA, in collaboration with CE Delft and Milieu.

Drawing upon existing research this report provides an examination of the potential climate impacts of shale gas production in the EU. It begins with a review of existing estimates of GHG emissions from shale gas production and of the potential options for abating emissions from shale gas processes. This evidence is then used to estimate the potential emissions that might be associated with shale gas exploitation in the EU. A brief review is also provided of the current legislative framework in the EU for controlling GHG emissions from shale gas operations. Finally the report provides an examination of the current GHG emissions reporting framework and explores the extent to which emissions from shale gas operations would be captured within the existing reporting requirements. Where there are identified gaps the report addresses the need for further reporting guidelines.

The report does not explore the potential role of shale gas in the future energy supply mix, or any potential implications of the exploitation of indigenous shale gas resources on the development of renewable or other energy sources in Europe. These issues are important considerations for energy and climate policy makers but are beyond the scope of this study. However, the results provided here can be used as inputs to discussions around these issues.

Shale gas exploitation

In the U.S. there has been a rapid growth in the exploitation of shale gas reserves, with production increasing by 48% between 2006 and 2010. Despite there being significant shale gas reserves in Europe, with technically recoverable shale gas resources estimated at approximately 18 trillion cubic metres (m^3), exploitation of shale gas to date has been limited and there is no commercial production at present.

The recent combination of higher natural gas prices, and the development of shale gas production in the U.S., has increased interest in shale gas exploitation within Europe. As a result permission is now being sought in several EU Member States for exploratory works with the explicit aim of bringing forward sites / projects for the extraction of shale gas.

A number of the key processes involved in the extraction of shale gas reserves are similar to conventional natural gas. However, certain process steps are more specific to unconventional gas extraction and the scale and complexity of operations differ from conventional practices. In particular, the extraction of shale gas typically involves a process known as hydraulic fracturing (fracking) where water, chemicals and proppants are pumped at high pressure into the well in order to open fractures in the rock and release the shale gas.

Other aspects of shale gas extraction differ from conventional natural gas. For example, additional drilling is required for horizontal wells, along with much greater volumes of water required in the hydraulic fracturing process.

Once production begins at the well the subsequent process steps in the exploitation of shale gas (processing, transportation, distribution) are largely comparable with conventional natural gas.

GHG emissions from shale gas production

The GHG emissions from shale gas production have been the subject of a number of studies since 2010. These studies have yielded a large variation in the estimated impacts of shale gas. Some studies, which have received a lot of media attention, have concluded that the lifecycle GHG emissions from shale gas may be larger than conventional natural gas, oil, or coal when used to generate heat and viewed over the time scale of 20 years (Howarth et al, 2011). However the majority of studies suggest that emissions from shale gas are lower than coal, but higher than conventional gas, based on other assumptions. These estimates are discussed further in this report.

In practice most of the existing studies have drawn upon a narrow set of primary data from shale gas operations in the U.S. Differences in the estimated emissions frequently arise from the interpretation by the authors of the primary data, in addition to the different underlying assumptions used in their GHG assessments. As new information sources have come to light this has led to new and improved estimates of the GHG impacts. However a number of uncertainties remain including: the level of emissions associated with the well completion stage; about levels of water re-use and treatment of waste water. Overall, the emissions from shale gas are dominated by the combustion stage. Significant emissions also arise from the well completion, gas processing and transmission stages, but the overall significance of these pre-combustion stages is less. Emissions from exploration have not been taken into account in any previous studies.

Drawing upon these studies, and their underlying data sources, a hypothetical analysis has been carried out of the potential lifecycle GHG emissions that may arise from shale gas exploitation within Europe. In our base case, which does not represent a preferred scenario, we have estimated the GHG emissions per unit of electricity generated from shale gas to be around 4% to 8% higher than for electricity generated by conventional pipeline gas from within Europe. These additional emissions arise in the pre-combustion stage, predominantly in the well completion phase when the fracturing fluid is brought back to the surface together with released methane. If emissions from well completion are mitigated, through flaring or capture, and utilised then this difference is reduced to 1% to 5%. This finding is broadly in line with those of other U.S. studies which found that generation from shale gas had emissions about 2% to 3% higher than conventional pipeline gas generation.

This study also considered sources of gas outside of Europe which make a significant contribution to European gas supply. Based on our hypothetical analysis, and drawing upon existing LCA studies for conventional gas sources, the analysis suggests that the emissions from shale gas generation (base case) are 2% to 10% lower than emissions from electricity generated from sources of conventional pipeline gas located outside of Europe (in Russia and Algeria), and 7% to 10% lower than that of electricity generated from LNG imported into Europe.

However, this conclusion is far from clear-cut. Under our ‘worst’ case shale gas scenario, where all flow back gases at well completion are vented, emissions from electricity generated from shale gas would be similar to the upper emissions level for electricity generated from imported LNG and for gas imported from Russia. This suggests, where emissions from shale gas are uncontrolled, there may be no GHG emission benefits from utilising domestic shale gas resources over imports of conventional gas from outside the EU[1]. In fact, for some pipeline sources emissions from shale gas may exceed emissions from importing conventional gas.

The relative comparison with coal is clearer cut. In our analysis, emissions from shale gas generation are significantly lower (41% to 49%) than emissions from electricity generated from coal. This is on the basis of methane having a 100 year GWP of 25. This finding is consistent most other studies into the GHG emissions arising from shale gas.

These conclusions are based on experiences drawn largely from the U.S. Whilst attempts have been made to take into account the different circumstances in Europe, and how this may influence overall emissions, this comparison is still largely hypothetical. Where the shale gas industry develops in Europe this information should be used to update the results of the analysis.

Best available technologies for reducing GHG emissions

One of the key assumptions which can influence the scale of emissions estimated in the life cycle analysis is the assumed management practices and technologies employed at the shale gas extraction site. The use of best practice techniques has the potential to significantly reduce emissions relative to other practices.

A large proportion of the best practice techniques that have been identified include measures which have been demonstrated, and are a regulatory requirement, in specific regions in North America (and will be a regulatory requirement in the U.S. from 2015). It is reasonable to assume that these techniques will be applicable in Europe with the following caveats:

[1] When reporting emission on a production basis (as is the case with national emissions inventories under the United Nations Framework on Climate Change), emissions arising from shale gas operation within Europe will be captured within the EU’s GHG emission inventory. However, emissions from e.g. conventional gas processing outside of Europe will not be accounted for in the EU’s GHG inventory – and instead will be captured in the inventory of the regions in which they are produced

- Geology: the effectiveness of certain techniques requires sufficient gas pressure, which may not be the case at all locations in Europe.
- Infrastructure: at least initially any captured gas which doesn't meet the required natural gas specification would need to be processed further. This may be a constraint if the pipeline or processing infrastructure is not in place and suitable connections available for transferring captured gas do not exist.
- Availability and experience in equipment / technology: to capture the gas released on well completion and re-fracturing activity. This may be an issue in initial stages of development until vendors develop suitable solutions.

With respect to emissions resulting from flow back from well completions, the application of Reduced Emissions Completions has the potential to reduce emissions by around 90%. These technologies have been used extensively in the U.S. both in response to regulations and existing drivers (e.g. economic value of captured methane). While there are some restrictions on the sites where these measures can be used, in principle, they have the potential to deliver significant reductions in emissions from this stage in the process.

Further emissions reductions can be achieved at other stages in the gas cycle. These measures are not specific to shale gas and are also applicable to conventional gas sources. These include measures such as: more efficient compressors; improved leak detection or utilisation of gas stemming from production testing.

Legislation controlling GHG emissions from shale gas production

The overview analysis of the EU legal acts identified as relevant to shale gas has shown that there are very few requirements applicable specifically to GHG emissions from shale gas projects.

The EIA Directive (85/337/EEC; 2011/92/EU (codified)) is the most relevant as it sets requirements as to the consideration of climate change effects and air emissions as part of a full EIA. It requires Member States to ensure that developers supply certain information, such as a description of estimated air emissions and significant environmental impacts resulting from the project, including air and climatic factors. Furthermore, the Directive provides for competent authorities to give an opinion on the information supplied which, as a minimum, should include a description of the measures envisaged in order to avoid, reduce and if possible, remedy significant adverse side effects.

However, despite these requirements, many uncertainties remain as to whether Member States would require an EIA for shale gas operations and if so how Member States should implement the EIA. For example the way in which they would implement the methodology to be used to quantify GHG emission baseline scenarios.

Directive 92/91/EEC concerning minimum requirements for improving the health and safety of workers in the mineral-extracting industries through drilling does not contain any provisions specifically relating to GHG emissions. It does, however, set requirements to protect workers from harmful and / or explosive substances. This would primarily apply to methane present in such concentration that it could represent a risk in terms of flammability for workers.

With regard to the Directive on Industrial Emissions (2010/75/EU) it is not clear in which circumstances it would apply to shale gas exploration and exploitation activities and whether its measures on air emissions would cover methane contained within flow back.

It is beyond the scope of this report to make specific recommendations on how to overcome the potential shortfalls identified above.

Finally, the EU ETS Directive (Directive 2003/87/EC) could provide precedents for the regulation of shale gas emissions, through its treatment of venting and flaring, and emissions related to carbon capture and storage processes.

In order to encourage the application of best available techniques the following could be further investigated:

- Consideration of the issues identified related to the scope of the EIA Directive with regard to shale gas exploration and exploitation activities (Annex I or II);
- Consideration of information requirements on measures taken by developers to limit GHG emissions under the EIA Directive, or other pieces of relevant legislation;
- Consideration of the need for measures to limit GHG emissions for shale gas exploration and exploitation;

- Consideration of the issues identified related to the scope of the Industrial Emissions Directive with regard to shale gas exploration and exploitation activities;
- Consideration of the application of the emission limit values requirements under the Industrial Emissions Directive to methane emissions from exploration and exploitation activities.

Consideration could also be given to the application of emission limit values for methane emissions from exploration and exploitation activities.

However, in principle the legislation described above could provide a good approach with which to enforce best shale gas technologies, although this would likely need to be supplemented by BAT reference documents, guidance specific to shale gas technologies and clarification on the applicability of key directives. Alternatives, such as voluntary agreements could also be considered, but additional measures would be required to ensure they are rigorously applied.

Assessment of the current GHG emissions reporting framework

In order to ensure the effective control of GHG emissions from potential shale gas development in Europe it is important to ensure that emissions, where they arise, are reported. This information is important for understanding the net impact of any shale gas installations, and for assessing the impacts of control measures, and the potential for further controls.

A review has been carried out of the adequacy of current GHG emissions reporting frameworks, under the auspices of the UNFCC and IPPC, with the view to identifying areas where improvements may be needed in relation to shale gas production.

The review has identified no emission factors, GHG estimation methods, industry activity or emissions data specific to shale gas Exploration and Production (E&P) sources within the EU. However, information and reporting protocols from regulators in Canada and the U.S. provide estimation methods and indicative emission factors for these sources that are specific to shale gas E&P which could be developed for application in the EU.

IPCC Guidelines do not provide emission estimation methodology details or emission factors that are applicable to calculate emissions from sources specific to shale gas E&P such as well completions, well work-overs and the related management of flow back fluid.

The UNFCCC reporting format (CRF) does not require that countries specify GHG emissions from shale gas E&P, or from any other specific technology or sub-sector. Emissions and activity data are typically reported by countries at an aggregated level across all gas E&P sectors, with additional methodological detail provided within National Inventory Reports (NIRs). The level of detail provided regarding emission estimations within the NIRs is subject to the discretion of the inventory agency.

Several process stages in shale gas E&P, including processing and compressing the gas for distribution, require the same steps as with conventional gas. Therefore the current IPCC Guidelines and national GHG inventory methodologies should be adaptable to allow inventory agencies to derive complete and accurate estimates for these sources. Development of appropriate emission factors (ideally at the gas-basin level) through gas sampling and compositional analysis will be required to ensure that emission factors reflect the local shale gas composition.

Table of contents

Appendices

Appendix 2: Knowledge review for reporting frameworks

List of Figures:

List of Tables:

1 Introduction

1.1 Background to the study

As readily accessible oil and gas reserves are becoming progressively limited the energy supply industry is exploring the potential of unconventional reserves which were previously too complex or too expensive to extract.

The United States of America (U.S.) is ahead of the rest of the world in this energy field. Extraction of coal bed methane and gas extraction from sandstone and shale represents a growing proportion of the energy mix in the U.S. In 2010, Shale gas represented ~23% of total U.S. dry gas production. From 2006 – 2010 shale gas production increased by 48% and is projected to account for 47% of U.S. production in 2035 (U.S. DOE, Energy Information Administration, 2011a). The U.S. has accessible reserves of over sixty trillion m^3 of natural gas, amounting to over one hundred years' of U.S. consumption at current levels. The total technically recoverable shale gas resource is estimated to be 13 trillion m^3 (U.S. DOE, Energy Information Administration, 2012).

Table 1 (U.S. DOE, Energy Information Administration, 2011b) shows the estimated technically recoverable resources for selected basins in Europe, compared to existing reported reserves production and consumption, during 2009. This indicates that technically recoverable shale gas resources in Europe are of a similar scale to those technically recoverable in the U.S.

Table 1: Estimated shale gas recoverable resource for select basins in Europe

State	2009 Natural Gas Market [(1)] (trillion cubic metres, dry basis)			Proved Natural Gas Reserves (trillion cubic metres)	Technically Recoverable Shale Gas Resources (trillion cubic metres)
	Production	Consumption	Imports (exports)		
France	0.00085	0.049	98%	0.006	5.10
Germany	0.0144	0.093	84%	0.18	0.23
Netherlands	0.0790	0.049	(62%)	1.39	0.48
Norway	0.103	0.0045	(2156%)	2.04	2.4
U.K.	0.059	0.088	33%	0.255	0.57
Denmark	0.0085	0.0045	(91%)	0.059	0.65
Sweden	-	0.0011	100%		1.16
Poland	0.0059	0.016	64%	0.164	5.30
Turkey	0.00085	0.035	98%	0.006	0.42
Ukraine	0.020	0.044	54%	1.10	1.19
Lithuania	-	0.0028	100%		0.113
Others[(2)]	0.014	0.027	50%	0.077	0.54
Total	**0.305**	**0.365**		**5.27**	**13.0**

(1) Dry production and consumption.

(2) Romania, Hungary, Bulgaria.

In Europe the estimates of technically recoverable shale gas reserves are continuing to evolve. These estimates have been informed by the exploratory works for shale gas production that have begun in several Member States. In the UK there are indications that recoverable reserves could potentially be of a similar scale to those of Poland and France (Cuadrilla Resources Ltd, 2011). However in Poland recent estimates suggest that recoverable shale gas reserves represent a much lower volume than previously thought, and potentially as much as 85% less than U.S. Energy Department estimates[2], with some companies ending exploration activities[3]. In France, shale gas developments have made little progress. The process of hydraulic fracturing is banned. However a committee has been set up which will assess the environmental risks of hydraulic fracturing and provide an opinion on the conditions for the implementation of research projects under public supervision. (Decree n° 2012-385 of 21 March 2012 and Law n° 2011-835 of 13 July 2011).

As with any drilling and extraction process shale gas extraction may bring environmental and health risks which need to be understood and addressed. In particular the contribution that potential shale gas production may make to climate change is a key issue. The European Commission (EC) has commissioned a number of studies to investigate the possible consequences of exploiting shale gas. This study is aimed at exploring the evidence base for GHG emissions from shale gas and possible ways to mitigate these emissions through legislation and reporting mechanisms.

1.2 Objectives of the study

The objective of this study is to provide state-of-the-art information to the European Commission on the potential climate implications of possible future shale gas production in Europe.

Four specific objectives were set out in the Invitation to Tender, as shown below.

Study Objectives

The objectives of this study are to:

- **Summarise and evaluate available knowledge on shale gas extraction technologies and practises and the related GHG emissions;**
- **Analyse the suitability of EU legislation and propose EU wide policies that could enforce the use of the most advanced technologies and practices to reduce GHG emissions;**
- **On the basis of the evaluation of the available data, provide an estimate of life cycle GHG emissions of electricity production using shale gas, taking into account all pre-production and production phases of shale gas extraction, and specifying both direct GHG emissions, indirect emissions from fossil fuels used to extract and transport the gas as well as fugitive emissions and venting. The life cycle GHG emissions should be based on current and future European power generation efficiencies as compared with life cycle emission estimates using other fossil fuels;**
- **Provide an assessment of the adequacy of GHG emissions reporting frameworks to cover fugitive emissions of the production of shale gas and, if needed, propose measures for its improvement.**

The study does not have an objective to explore the potential role of shale gas in the future energy supply mix, or any potential implications of the exploitation of indigenous shale gas resources on the development of renewable or other energy sources in Europe. These issues are important considerations for energy and climate policy makers, but are beyond the scope of this study. However, the results provided here can be used as inputs to any discussions around these issues.

1.3 Report Structure

In addition to this introductory chapter, the report is organised into the following chapters:

- Chapter 2: Shale gas exploitation, provides an overview of shale gas production and the processes involved;
- Chapter 3: Greenhouse gas emissions from shale gas production, provides a review of existing estimates of emissions from shale gas operations;

[2] http://www.bloomberg.com/news/2012-03-21/poland-may-have-768-billion-cubic-meters-shale-gas-reserves-1-.html
[3] http://finance.yahoo.com/news/exxonmobil-ends-shale-gas-exploration-poland-113831058--finance.html

- Chapter 4: Best available techniques for reducing GHG emissions, explores potential emissions abatement options;
- Chapter 5: Hypothetical estimation of the lifecycle GHG emissions from shale gas exploitation in Europe, provides a first estimate of the potential emissions that may be associated with future shale gas operations in Europe;
- Chapter 6: Legislation controlling GHG emissions from shale gas production, provides an initial review of potential legislative options for controlling any potential emissions from shale gas operations;
- Chapter 7: Assessment of current GHG emissions reporting framework, explores how emissions from shale gas operations may be reported within existing frameworks;
- Chapter 8: References, lists the main references;
- Chapter 9: Glossary, provides a glossary of key terms.

2 Shale gas exploitation

2.1 Introduction

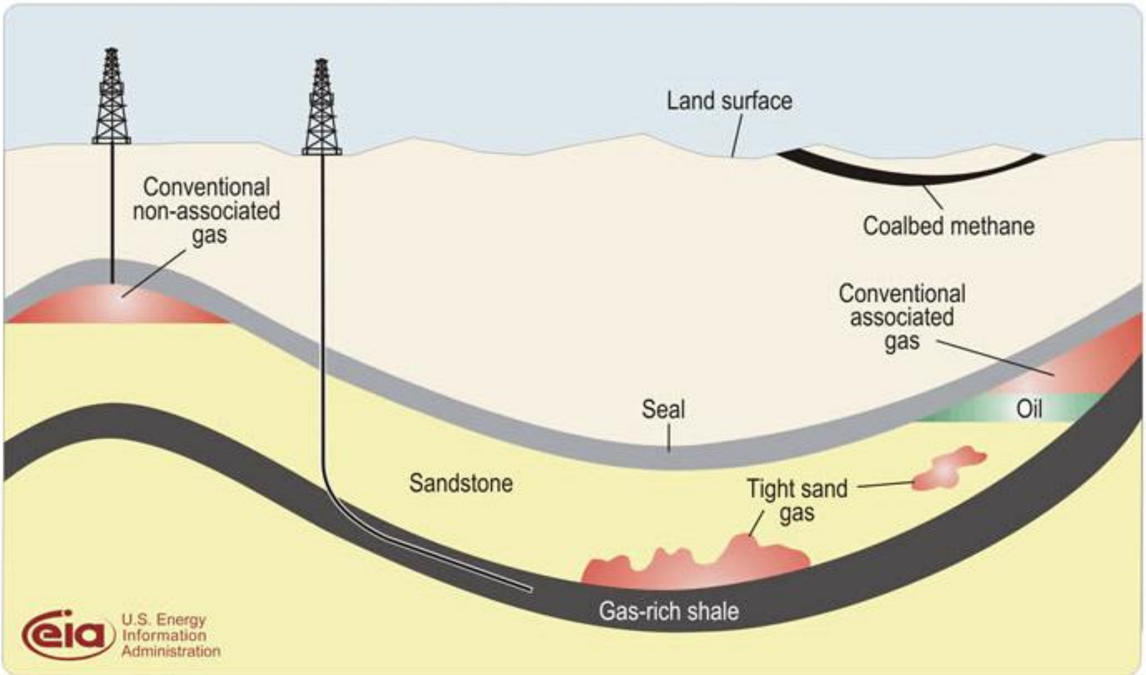
This chapter provides an overview of shale gas exploitation, including the market context, and a summary of the key process stages required for its extraction.

2.2 Overview of shale gas production

Conventional gas refers to gas trapped in multiple, relatively small, porous zones in rock formations. This gas is often difficult to find but, once discovered, is typically the easiest and most cost-effective to extract. Conventional reservoirs (rock formations where gas is found) are typically in sandstone, siltstone and carbonate (limestone) (British Geological Survey, 2011).

Shale gas, along with tight gas and coal bed methane, is an example of unconventional natural gas. The term "unconventional" in this context refers to the characteristics of the reservoir, or bearing rock formation, from which the gas is extracted. The term does not refer to the characteristics or composition of the gas itself which is similar in composition to "conventional" natural gas. Figure 1 schematically illustrates the location of these different types of natural gas deposits.

Figure 1: Schematic cross-section of the subsurface illustrating types of natural gas deposits (From: U.S. DOE, Energy Information Administration, 2011b)



'Gas shales' (also known as shale beds) are formations of organic-rich shale, a sedimentary rock formed from deposits of mud, silt, clay, and organic matter. As shown in Figure 1, the gas shales (shales) are continuous deposits over large areas (stretching over thousands of square kilometres (U.S. EIA 2011), which have very low permeability and low natural production capacities.

The low permeability of the rock means that substantial quantities of natural gas can be trapped within their pores, but the shales must be artificially stimulated (fractured) to enable its extraction. Techniques such as directional / horizontal drilling and hydraulic fracturing have been developed in order to facilitate the extraction of the gas from the shales.

Directional / horizontal drilling allows the well to penetrate along the hydrocarbon bearing rock seam. This maximises the rock area that, once fractured, is in contact with the well bore and so maximises the well production in terms of the flow and volume of gas that may be collected. These techniques originate in the U.S.

2.3 Process stages for the extraction of shale gas

For an individual unconventional gas well, the process of well development is as follows (adapted from NYSDEC 2011 p5-91 to 5-137):

Figure 2: Well development process

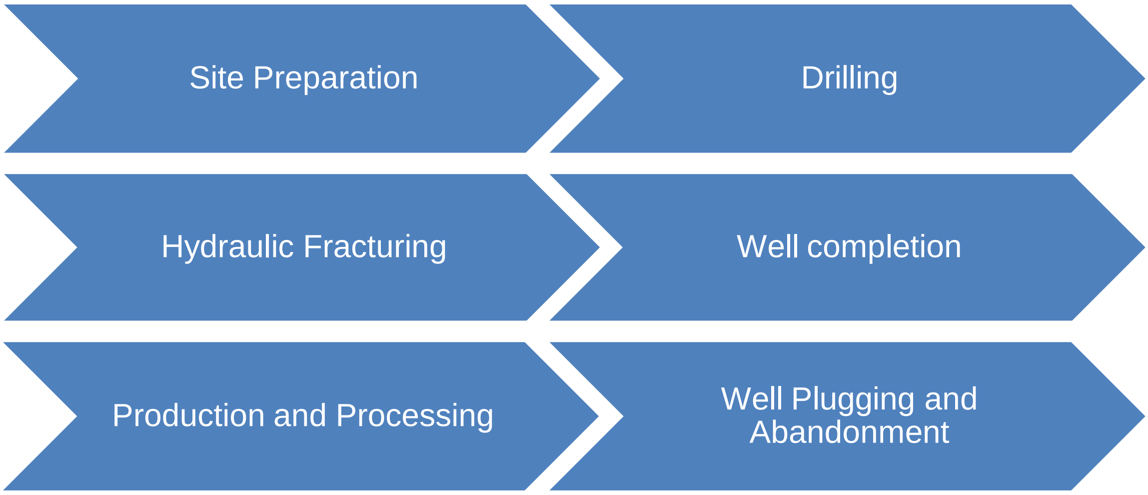
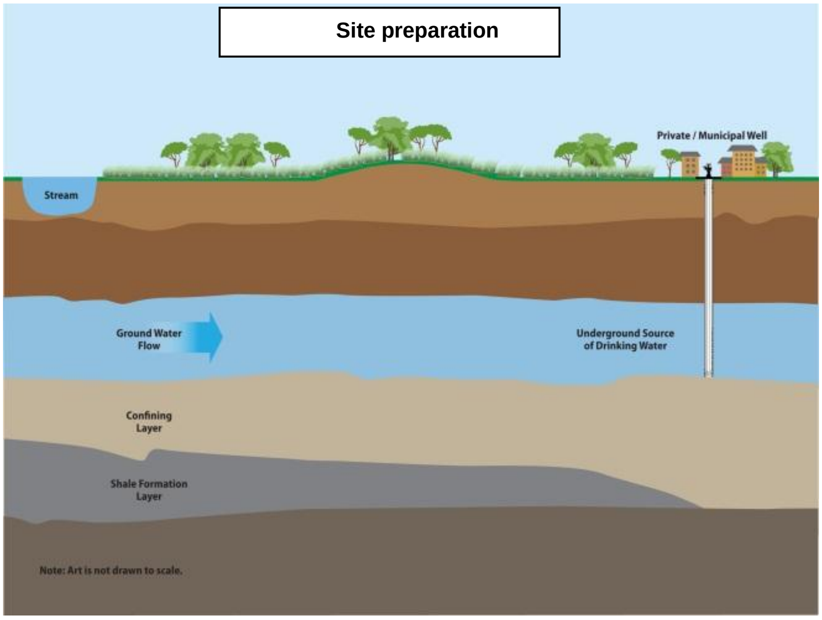
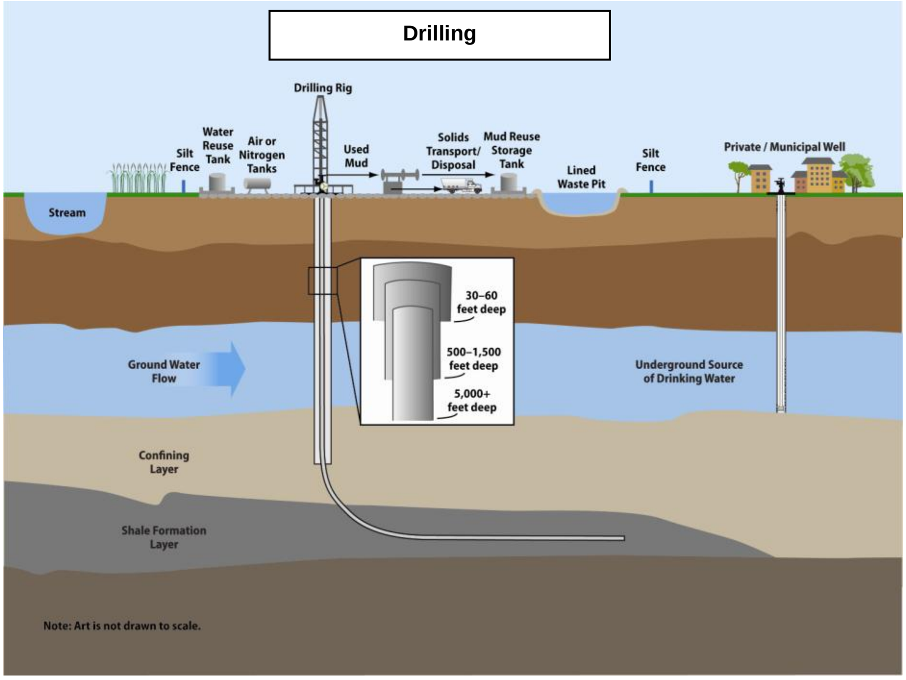
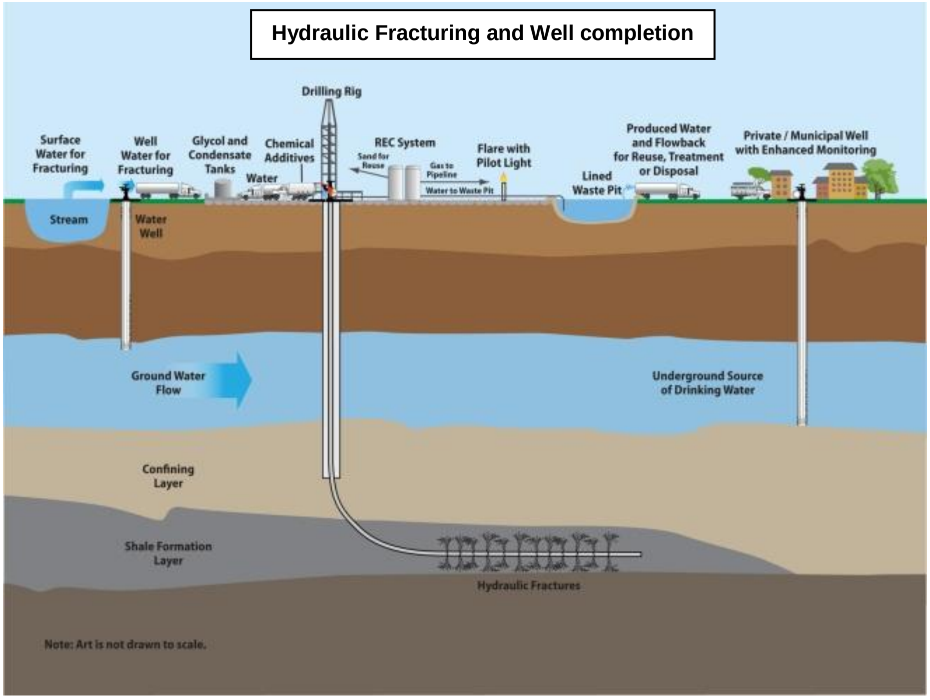


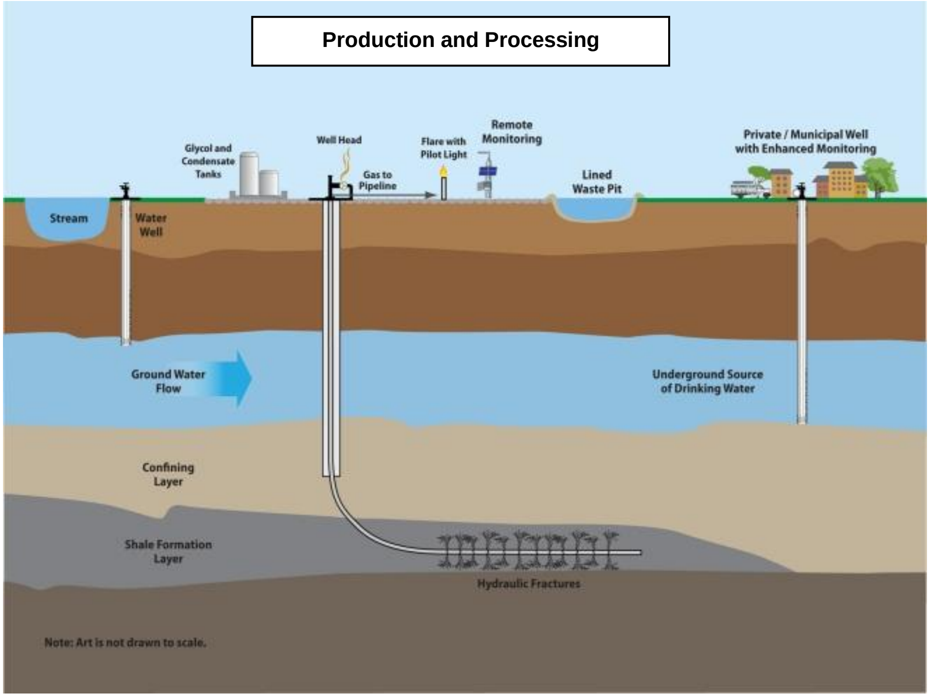
Figure 3 provides an illustration of the principal stages in the hydraulic fracturing process.

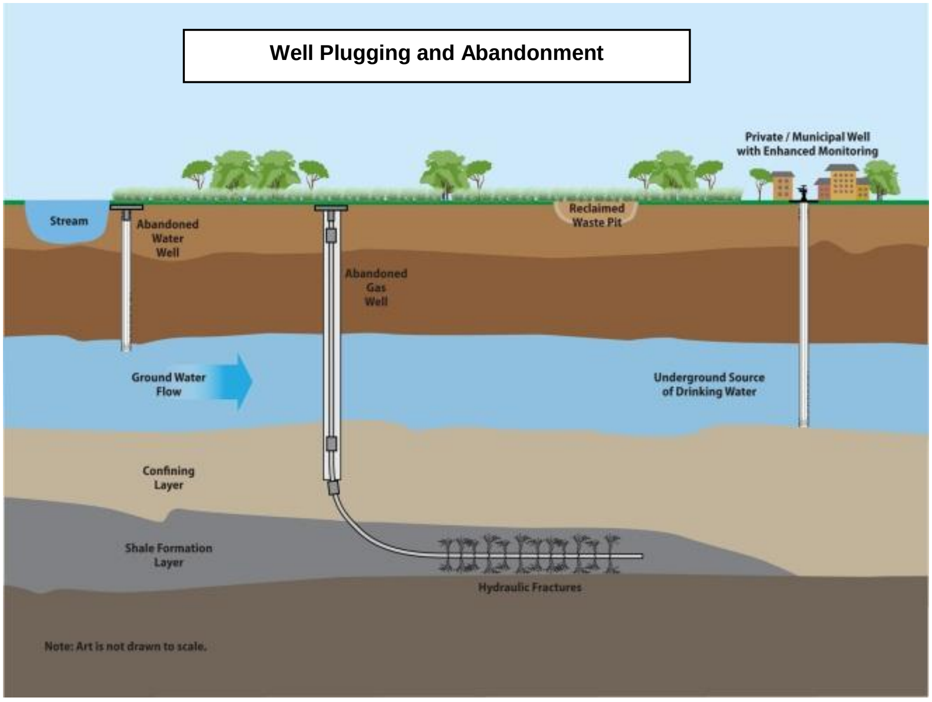
Figure 3: Stages in well development




Drilling
Drilling Rig
Water Reuse Tank
Silt Fence
Air or Nitrogen Tanks
Used Mud
Solids Transport/ Disposal
Mud Reuse Storage Tank
Lined Waste Pit
Silt Fence
Private / Municipal Well
Stream
30-60 feet deep
500-1,500 feet deep
5,000+ feet deep
Ground Water Flow
Underground Source of Drinking Water
Confining Layer
Shale Formation Layer
Note: Art is not drawn to scale.


Hydraulic Fracturing and Well completion
Drilling Rig
Surface Water for Fracturing
Well Water for Fracturing
Glycol and Condensate Tanks
Chemical Additives
Water
REC System
Flare with Pilot Light
Produced Water and Flowback for Reuse, Treatment or Disposal
Lined Waste Pit
Private / Municipal Well with Enhanced Monitoring
Stream
Water Well
Ground Water Flow
Underground Source of Drinking Water
Confining Layer
Shale Formation Layer
Hydraulic Fractures
Note: Art is not drawn to scale.





Note: Figures are illustrative, and not necessarily representative for a specific development site.

In estimating the GHG emissions in this report we have defined the stages as:

- Pre-production, which includes site preparation / drilling / hydraulic fracturing / well completion / waste and waste water treatment;
- Production and processing;
- Transport and distribution;
- Well plugging and abandonment.

These process stages are described briefly below.

2.3.1 Pre-production stage

This stage includes all of the activities required to prepare the site for shale gas extraction. This includes: site preparation; drilling; initial hydraulic fracturing and associated flow back; waste and waste water treatment.

2.3.1.1 *Site preparation*

This process involves the establishment of appropriate supporting infrastructure for the well. This starts with the initial site investigation and includes the construction of a well pad and the supporting infrastructure, including:

- Access roads;
- Well pad;
- Drilling rigs;
- Gas storage and processing facilities;
- Pipelines and compressors to transport the gas off-site;
- Water storage and treatment facilities.

This type of construction is typical for industrial sites including conventional gas production.

2.3.1.2 *Drilling*

As outlined in Section 2.1 the extraction of shale gas requires both vertical drilling and horizontal drilling. The vertical drilling process is very similar to drilling for conventional fossil fuels. A temporary drill head is brought to the site and erected over the well head. Typically compressed air or freshwater mud is used as the drilling fluid. The depth of drilling will depend on the geology, but may reach depths of 2km. Horizontal drilling requires a larger temporary drilling rig and may extend from the well head for more than 1km (NYSDEC, 2011). This will generate cuttings in excess of 140 m^3 (Broderick et al, 2011). This amounts to approximately 40% more drill cuttings compared to a vertical well (NYSDEC, 2011).

Once the well is drilled it is cased to seal it from the surrounding rock. Typically the casing is in the form of, depending on depth, one or more steel pipes lining the inside of the drilled hole which are cemented in place. The well is then fitted with a well head which is suitably designed and pressure rated for the hydraulic fracturing operations.

2.3.1.3 *Hydraulic fracturing*

Hydraulic fracturing (fracking) is the process used by gas producers to stimulate wells and recover natural gas from sources such as coal beds and shale gas formations. During hydraulic fracturing, fluids (usually consisting of water and chemical additives) together with a ‘proppant’ are pumped down the well at high pressure. When the pressure exceeds the rock strength the fluids open or enlarge fractures. These fractures can extend a few hundred metres away from the well. As the fractures are created the propping agent enters the fractures. This prevents them from closing when the pumping pressure is released.

The fracturing fluids are primarily water-based fluids mixed with additives. Chemical additives are mixed with base fluids. This modifies the fluid mechanics to increase performance of the fracturing fluid but also to prevent corrosion to the well pipes. The composition of fracturing fluids vary, King (2012) states that the proppant makes up 1% to 1.9% of the total volume. NYSDEC (2011) gives the proppant between 8% and 15%. Fracturing fluid performance can be measured by several different standards, but most typically, is measured by the ability of the fluid to place proppant into the fractures.

The proppant is needed to ‘prop’ open the fractures once the pumping of fluids has stopped and the pumping pressure is reduced. Sand is commonly used as the proppant, but in the U.S. there has been a move away from sand into specialised fracturing beads and propping agents[4].

Once the fracture has initiated additional fluids are pumped into the wellbore to continue the development of the fracture and to carry the proppant deeper into the formation. The additional fluids are needed to maintain the downhole pressure necessary to accommodate the increasing length of

[4] http://ceramics.org/ceramictechtoday/2011/12/15/engineered-proppants-for-hydrofracturing/

the opened fracture. This ensures that the fracture remains open and that any gas that exists can flow into the well.

In terms of the quantities of water required, NYSDEC (2011) suggest that each stage in a multi-stage fracturing operation requires 1,100 - 2,200 m^3 of water, so that the entire multi-stage fracturing operation for a single well could requires around 9,000 - 29,000 m^3 of water. Industry sources INGAA Consulting (2008) and Naturalgas.org (2010) suggest up to 13,200 m^3 of water is required per well for hydraulic fracturing with existing technologies.

In addition to the initial hydraulic fracturing stage, the process may over time be repeated several times to extend the economic life of the well.

2.3.1.4 *Flow back and waste water treatment*

After hydraulic fracturing is completed a proportion of the injected fracturing fluid, depending on the geological formation, rises to the surface. This recovered fluid is called flow back fluid (flow back). In addition to flow back, naturally occurring water, termed Produced Water, flows to the well head. This liquid, combining flow back and produced water, is collected and sent for treatment and disposal or re-use where possible.

Specifically flowback fluid refers to fluid returned to the surface after a single hydraulic fracture process has occurred, but before the well is placed into production. It typically consists of returned fracturing fluids in the first few days following hydraulic fracturing. This is progressively replaced by produced water.

Within the flowback fluid there is a varying content of water. As this is returned to the surface it can be classified either as water, i.e. that which will be used in further hydraulic fracturing stages, or as waste water, i.e. that which is unsuitable for reuse and is discharged from the site for treatment or recycling. The volume of water that can be recycled is variable. Yoxtheimer (2012) states that 77% of flow back water is estimated to have been recycled in the U.S. in 2011, however in the Barnett shale, approximately 1% - 2% of water is recycled; in the Fayetteville shale where there is only 10% flowback, most of that is re-used but that is atypical. The flow back fluid, in addition to water, contains a combination of sand, hydrocarbon liquids and natural gas (see Section 2.2.1.3). Where the water within the flow back fluid cannot be reused, it requires disposal. The waste water may be disposed directly by injection into a used well, or transported for treatment at a waste water treatment facility.

Produced water is fluid displaced from the shale formation, and can contain substances that are found in the formation. This may include dissolved solids (e.g. salt), gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium), and organic compounds, Produced water will typically begin to flow to the well head following an initial hydraulic fracture and may continue to flow to the well head for the duration of gas extraction. Because of the nature, and content, of produced water it is typically collected in tanks for later treatment.

2.3.2 Production and processing

Once the drilling and hydraulic fracturing phases are complete a production well head is installed in order to collect the gas and transfer it to a processing plant prior to distribution. The distance over which this occurs will vary depending on the location of the site.

2.3.2.1 *Production timescales*

Shale gas wells initially produce a large amount of gas (the free gas in the rock) but this reduces rapidly, typically over a period of several years. The average economic lifetime of wells, which will be influenced by the price of gas, is likely to be 10 - 15 years. A study of actual production rates in the Barnett Shale found that the average well lifespan is 7.5 years (Berman, 2009). For the Marcellus shale gas industry, it is estimated that the production rate will decrease by 80% in the first five years and by 92% by 10 years, falling another 3% per year thereafter (NYSDEC, 2011).

2.3.2.2 *Re-fracturing*

During the commercial operation of a shale gas well the operators may extend the operational life of the well, or increase its production over a specific time period, by repeating the hydraulic fracturing process (known as re-fracturing / re-fracking). This process is very similar to the hydraulic fracturing process described above.

2.3.2.3 *Processing*

The chemical composition of the shale gas produced depends on the geology of the shales. Typically the gas consists of methane (CH_4), heavier hydrocarbons and carbon dioxide (CO_2). During this process stage the heavier hydrocarbons and carbon dioxide are removed and the remaining methane is compressed for distribution. The gas is also dehydrated, commonly using glycol dehydrators, to remove the water content. This process is essentially no different from the production of conventional gas. Also the mix of the recovered gas will affect the calorific value of the gas and therefore the overall emissions intensity from the well.

2.3.3 Transport and distribution

This stage involves the distribution of the gas in pipelines. This process stage is essentially no different from the supply of conventional gas except that the route from the well to the end user may be different e.g. in the case of indigenous production shorter than in the case of imported natural gas.

2.3.4 Well plugging and abandonment

Once the well has reached the end of its economic lifetime (or if a well does not produce any gas) it must be properly decommissioned and plugged in order to protect the surroundings and subterranean environment. This involves the removal of all the equipment at the well site and any distribution infrastructure. The well is then plugged with cement in order to prevent further fugitive emissions. This is essential to ensure that the well is left in a safe and stable condition for the future.

2.4 Comparison of high volume hydraulic fracturing and conventional hydrocarbon extraction practices

Table 2 sets out the stages of a high volume hydraulic fracturing activity and summarises the differences between this and conventional hydrocarbon production (adapted from U.S. Environmental Protection Agency (U.S. EPA, 2011a and NYSDEC, 2011).

Table 2: High Volume Hydraulic Fracturing: Stages, Steps, and Differences from Conventional Hydrocarbon Practices

Development & Production Stage	Step	Differences from Conventional Hydrocarbon practices
Site Selection and Preparation	Site identification	None
	Site selection	None None None None
		More space required during hydraulic fracturing for tanks / pits for water / other materials required for fracturing process (NYSDEC, 2011).
		More lorry movements during hydraulic fracturing than conventional production sites due to need to transport additional water, fracturing material (including sand / ceramic beads) and wastes.
		Obtaining large volumes of water (9,000 to 29,000 m^3 per well) (NYSDEC, 2011). Disposing of large volumes of contaminated water (9,000 to

Development & Production Stage	Step	Differences from Conventional Hydrocarbon practices
		25,000 m^3 per well) (Derived from Broderick et al, 2011).
		Storage of large volumes of water (9,000 to 29,000 m^3 per well). Will require sufficient trucks / tanks onsite to manage flow back (e.g. 250 - 625 trucks at 40 m^3 per truck) (derived from NYSDEC, 2011).
	Site preparation	Installation of additional tanks / pits sufficient to accommodate up to 29,000 m^3 of make-up water. 6 - 10 wells / pad (NYSDEC, 2011) compared to 1 well / pad for conventional production. Fewer well pads / hectare: 1 multi-stage horizontal well pad can access c. 250 hectares, compared to c.15 hectares for a vertical well pad (NYSDEC, 2011).
Well Design, Construction and Development	Selection of horizontal vs. vertical well	Both conventional and unconventional wells are drilled through water bearing strata and require same well design standards.
	Well drilling	Horizontal drilling produces longer well bore (vertical depth plus horizontal leg) requires more mud and produces more cuttings / well. Typically 40% more mud and cuttings for horizontal well, depending on depth and lateral extent (NYSDEC, 2011). Horizontal drilling requires specialist equipment: larger diesel engines for the drill rig uses more fuel and produces more emissions. Equipment is on site for a longer time (typically 25 days for horizontal well compared to 13 days for vertical well; NYSDEC, 2011). However, horizontal wells provide a more efficient means to access gas reserves than conventional vertical wells, other factors being equal (U.S. EPA, 2011a). Consequently, horizontal drilling from a limited number of well heads would in principle be preferable to vertical drilling from a larger number of well heads. In practice horizontal drilling techniques are normally used to open up reserves, which would not otherwise be viable with vertical drilling techniques, and so this comparison is not directly relevant.
	Casing	Casing material must be compatible with fracturing chemicals (e.g., acids). Casing material must also withstand the higher pressure from fracturing multiple stages.
	Cementing	Hydraulic fracturing has the potential to damage cement: may pose a higher risk during re-fracturing, although unclear at

Development & Production Stage	Step	Differences from Conventional Hydrocarbon practices
		present (U.S. EPA, 2011a).
Well Completion	Hydraulic Fracturing: Water sourcing	Requirement to abstract and transport water to wellhead for storage prior to hydraulic fracturing operations.
	Hydraulic Fracturing: Chemical Selection	Current U.S. information indicates that the composition of chemicals used in high volume fracturing is similar to that used in conventional fracturing (NYSDEC, 2011). The composition of fracturing fluids to be used in the EU is uncertain. Less harmful additives are being developed and used at lower concentrations in both conventional and unconventional applications (King, 2011).
	Chemical Transportation	Transport of large volumes of water, chemicals and proppant to well pad (up to 25,000 m^3).
	Chemical storage	More chemical storage required for high volume hydraulic fracturing (as for transportation above).
	Chemical Mixing	Mixing of water with chemicals and propping agent (proppant).
	Hydraulic Fracturing: Perforating casing	Conventional wells are hydraulically fractured in North America, although this is uncommon in Europe. The amount and extent of perforations may be greater for high volume hydraulic fracturing.
	Hydraulic Fracturing: Well injection of hydraulic fracturing fluid	Monitoring requirements and interaction of fracturing fluid with formation also occur in conventional wells but more extensive in high volume fracturing due to longer well length in contact with formation (up to 2,000 metres for high volume hydraulic fracturing compared to up to a few hundred metres for conventional well depending on formation thickness). More equipment required: series of pump trucks, fracturing fluid tanks, much greater intensity of activity.
	Hydraulic Fracturing: Pressure reduction in well / to reverse fluid flow recovering flow back and produced water	'Flow back' of fracturing fluid and produced water containing residual fracturing chemicals, together with materials of natural origin: brine (e.g., sodium chloride), gases (e.g., methane, ethane, carbon dioxide, hydrogen sulphide, nitrogen, helium), trace elements (e.g. mercury, lead, arsenic), naturally occurring radioactive material (e.g. radium, thorium, uranium), and organic material (e.g. acids, polycyclic aromatic hydrocarbons, volatile and semi-volatile organic compounds) (U.S. EPA, 2011a).
Well completion (continued)	Connection of well pipe to production pipeline	In principle no difference to conventional wells. However, potential for impacts in areas which would not otherwise be commercially viable.
	Reduced	Larger volume of flow back and sand to manage than

Development & Production Stage	Step	Differences from Conventional Hydrocarbon practices
	Emission Completion	conventional wells (9,000 to 25,000 m^3 per well) (Derived from Broderick et al, 2011).
	Well pad removal	Larger well pad (with more wells / pad) with more ponds and infrastructure to be removed, as described above.
Well Production	Construction of pipeline	Exploitation of unconventional resources may result in a requirement for gas pipelines in areas where this infrastructure was not previously needed.
	Production	Produced water will contain decreasing levels of fracturing fluid as well as hydrocarbons. Conventional wells are often in wet formations that require dewatering to maintain production. In these wells, produced water flow rates increase with time. In shale and other unconventional formations, produced water flow rates tend to decrease with time.
Well Site Closure	Remove pumps and downhole equipment Plugging to seal well	Closure of unconventional wells is similar to closure of conventional wells.
Post-closure	Potential for methane seepage to occur in the long-term if seals or liners break down	Closure of unconventional wells is similar to closure of conventional wells.

3 Greenhouse Gas (GHG) emissions from shale gas production

3.1 Introduction

The GHG emissions associated with shale gas production have been the subject of previous life cycle assessment (LCA) studies. A review of these studies has been carried out in order to better understand the potential scale of emissions, the main emission causing activities, and the reasons for any differences in previous estimates.

3.2 Compilation of the evidence base

Much of the current evidence base originates from the U.S. There is little European evidence as significant shale gas operations are, with the exception of limited exploration activities, not yet operational in Europe and typical practices are yet to be established.

Most studies estimating the GHG emissions from shale gas production are relatively recent, with the number of studies growing steadily over the past 2 years. As far as possible, the analysis presented represents the state of research at the time of writing. It is important to note that certain limitations and uncertainties in the evidence base remain. These are discussed further below.

In practice, there are a small number of LCA studies that are regularly referenced by the wider literature. These include the studies by Broderick et al (2011); Howarth et al (2011); Jiang et al (2011), Santoro et al (2011); and Stephenson et al (2011). With the exception of Santoro et al (2011), all of these papers have been published in peer-reviewed journals or publications. Other studies have been prepared by government agencies. For example, Skone et al (2011) is a report prepared by the U.S. Department of Energy National Energy Technology Laboratory. These studies form the basis of the review conducted for this report.

The LCA studies reviewed draw upon a wider pool of primary research and data on specific shale gas operations and practices. These sources are used to support the assumptions that are made by the study authors in their emissions modelling. The source of these primary studies is diverse, and includes industry estimates, as well as estimates by governments and their agencies. Some of the main studies were referenced in the previous chapter, including reports from the U.S. EPA (2011b) and NYSDEC (2011). These studies have typically not been independently peer-reviewed, although in the case of the government studies may have been subject to formal consultation with stakeholders. The estimates also frequently originate from specific sites or regions, so may not be fully applicable to other locations.

The following sections describe our findings for each of the process stages described in Section 2.2. As with the original LCA studies the GHG emissions have only been considered from the perspective of normal state operating conditions, therefore fault conditions have not been considered.

3.2.1 Methodological basis

In order to provide a useful comparison of the different studies it is important to as far as possible present the results on an equivalent basis. This includes presenting the results in consistent units. This has been the aim in the summary presented below. This has required some conversion of the values presented in the original studies. The conversions that have been made in order to facilitate this comparison are described further in Appendix 1.

One important assumption that is important to correct for is the assumed Global Warming Potential (GWP) of methane. This reflects the relative potency of methane as a GHG, and its lifetime. Methane is a more potent GHG than CO_2 but has a shorter lifetime in the atmosphere, a half-life of about fifteen years, versus more than 150 years for CO_2. As a result, there are different ways to compare the effect of methane and CO_2 on global warming. One way is to evaluate the GWP of methane, compared to

CO_2, averaged over 100 years. The 4th Assessment report of the IPCC (IPCC, 2007) gives a value of 25 (on a mass basis) for this 100-years GWP, revised up from their previous estimate of 21. This value is relevant when looking at the long-term relative benefits of eliminating a temporary source of methane emissions versus a CO_2 source (IEA, 2012).

Averaged over 20 years, the GWP, estimated by the IPCC, is 72. This figure can be argued to be more relevant to the evaluation of the significance of methane emissions in the next two or three decades, which will be the most critical to determine whether the world can still reach the objective of limiting the long-term increase in average surface temperatures to 2 degrees Celsius (IEA, 2012). Moreover, some scientists have argued that interactions of methane with aerosols reinforce the GWP of methane, possibly bringing it to 33 over 100 years and 105 over 20 years (Shindell, 2009). These recent analyses are under review by the IPCC.

Since different studies may apply different GWP values for methane when expressing the results in carbon dioxide equivalents (CO_2eq), it is important to make this clear when making comparisons. In the results presented below emissions are presented in CO_2eq using GWP (100 years) of 25. Some further exploration of the potential influence on the assumed GWP on the overall results is presented in the summary section at the end of this chapter.

3.3 Pre-production stage

Pre-production comprises a number of subsidiary activities. These include:

- Site preparation (access road and well pad production);
- Drilling;
- Hydraulic fracturing.
- Well completion and waste water treatment.

GHG emissions can arise from each of these activities. The main sources of emissions and the relative scale of emissions are discussed further below. The estimates are based upon published literature. Where possible comparisons between different studies have been made and differences in the results explained. However, due to a lack of transparency in the calculations or differences in approach, it has not been possible to make direct comparisons in all cases.

For each of the sub-stages a summary of the estimates is provided in the tables that follow. In presenting the results the emissions estimates have been calculated as absolute values in consistent units (per well pad). This corrects for the different assumptions that have been made in the studies e.g. the productivity of the wells.

3.3.1 Site preparation

3.3.1.1 *Emission sources*

GHG emissions associated with the site preparation include energy-related emissions from the use of equipment to clear the site (e.g. clearing vegetation) and from the construction of necessary transport infrastructure (e.g. roads). Emissions associated with changes in land use type (e.g. removal of carbon stocks) are also relevant. Indirect emissions can also be associated with the materials used in the site preparation activities (e.g. embedded emissions in construction products), and are discussed further below.

3.3.1.2 *Emission estimates*

The estimated emissions will relate to the particular characteristics of the site of the well. The energy used in land clearance and the construction of transport infrastructure will be related to the size of the site and the proximity of existing infrastructure. Likewise the emissions associated with changes in carbon stocks will depend on the existing land use type.

In Table 3 existing estimates of the emissions from site preparation are compared.

Table 3: Existing estimates of emissions associated with site preparation

Source	Emissions estimate (per well) (tCO_2eq)	Relevant assumptions and methodology
Jiang et al (2011)	330 - 390	Based on a Marcellus shale gas well pad. **Vegetation clearance:** Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss from land use change. Area of well pad assumed was 2.0 ha. Area of access roads assumed was 0.6 ha. **Well pad and access road construction:** Detailed cost estimate used to inform an EIO-LCA model.
Santoro et al (2011)	158	Based on a Marcellus shale well pad. **Vegetation clearance:** Assumes 5 ha per site, or 0.62 per well (including access roads, and the areas required for gathering line construction). Includes initial carbon loss, and foregone carbon sequestration. **Disturbances:** Combustion emissions are based on 1,235 GJ ha for bulldozers and 98 GJ ha for excavators.
Stephenson et al (2011)	Not Reported	Land use change emissions associated with access roads and well pad construction were assessed but found to not make a material difference.

The estimates provided by Jiang et al (2011) and Santoro et al (2011) are similar in scope, but Jiang et al (2011) estimate emissions that are nearly double those from Santoro et al (2011). This is despite Jiang et al (2011) assuming a smaller land area. This variation therefore relates to methodological differences. The Santoro et al (2011) estimate (as presented above) only includes emissions from energy use. However, the Extended Input-Output (EIO) methodology used by Jiang et al (2011) will include a wider range of impacts as it is based upon total expenditure associated with construction, and it is not restricted to just fuel related impacts.

GHG emissions from this sub-stage are dominated by carbon dioxide from energy use, with some small amounts of methane and nitrous oxide emissions also arising from combustion. Land use clearance is also associated with sequestrated carbon.

3.3.1.3 *Uncertainties and data gaps*

The main uncertainties relate to the representativeness of results from one site to the next. Site specific characteristics have an important influence on the overall results.

There are also certain methodological uncertainties. For example, the emissions associated with vegetation clearance and other land use changes are the subject of debate.

The importance of these assumptions can be related to the overall significance of the site preparation stage in the total life-cycle impacts. As described below, these emissions are generally small in comparison to other stages in the life cycle.

3.3.1.4 *Applicability of estimates to the EU*

The estimates are applicable to the EU as similar practices will be required for the development of shale gas wells in Europe. However, due to the generally higher population densities in Europe, it is argued by some that shale gas developments might have a smaller overall land-footprint compared to US practices, or to conventional gas developments in Europe as developers may be under more pressure to reduce the impact of well developments on the landscape, although this would require further analysis. At the same time, developments may be closer to existing infrastructure. For example, Broderick et al (2011) refer to plans by Cuadrilla for exploration and production (E&P) from the Bowlands Shale in the UK, quoting a well pad size of 0.7ha, which will contain 10 wells.

3.3.2 Energy use in drilling and pumping

3.3.2.1 *Emission sources*

Emissions arise from the energy used in the drilling of the well bore, and in the pumping of water and other material during hydraulic fracturing.

During the drilling phase a temporary drilling rig is brought to the well pad and erected on site. Energy for the drilling operation (and all ancillary support activities such as well pad lighting and crew housing) is normally provided by large, diesel-fired internal combustion engines. In some instances the drilling rig may be powered by the local electric grid instead of diesel engines. The drilling rig engines are a source of combustion-related pollutants including CO_2. The quantity of fuel consumed, and the associated emissions, will depend upon the length of the well bore. Each horizontal wellbore may be around 1,000 to 1,500 metres in lateral length but can be more (NYSDEC, 2011). This step of the process is the same for conventional and unconventional gas wells, with the exception of horizontal drilling, which is specific for shale gas wells.

Hydraulic fracturing is essential for shale gas production. It involves the high pressure injection of the fracturing fluid into the well. The process is typically powered by large, diesel-fired internal combustion engines.

The fracturing phase requires significantly more energy to fracture the formation than required to drill the wellbore. Depending on the number of fracturing phases involved in stimulating the formation this step may last from several days to several weeks. For example a multi-stage fracturing operation for a 1200 metre lateral well typically consists of eight to thirteen fracturing stages (NYSDEC, 2011).

3.3.2.2 *Emission estimates*

Existing estimates of emissions from drilling and hydraulic fracturing are based upon bottom up estimates of the quantity of fuel required, or total power requirements, which is then applied to an appropriate emissions factor. The most important assumption in this calculation is therefore the assumed fuel and / or power requirements, which in turn relate to the specific characteristics of the site (e.g. depth and lateral length of the well and number of wells).

In Table 4 existing estimates of the emissions from drilling and hydraulic fracturing are compared. To ease comparison, results are presented as absolute emissions per well.

Table 4: Existing estimates of emissions associated with drilling

Source	Emissions estimate (per well) (tCO_2eq)	Relevant assumptions and methodology
Jiang et al (2011)	610 - 1,100	**Emissions from drilling:** Vertical drilling depth 2,600 metres, Horizontal drilling length 1,200 metres. Power of drilling rig assumed to be 2,500 to 6,600 HP, will a drilling time of 210 to 380 hours. Lifecycle diesel engine emission factor of 635 g CO_2eq per HP–hr.
	230 - 690	**Emissions from pumping:** Pumping energy multiplied by emission factor. Power of pumping equipment assumed to be 34,000 HP, with a pumping time of 10 to 30 hours. Lifecycle diesel engine emission factor of 635 g CO_2eq per HP–hr.

Santoro et al (2011)	1,426	Total well length of 3,878 metres, consisting of 2,678 metres depth and 1,200 metres of lateral length. Energy use based on a single well. **Emissions from drilling:** Includes prime movers - the drilling rig's main power source. Drilling time is assumes to last 4 weeks with engines running 24hr/day. **Emissions from pumping:** Use of pumps with power of 9,300 HP. Fracturing time is assumed to last 70 hours of pump engine time.
Stephenson et al (2011)	771	**Emissions from drilling**: Assumed to be the same as conventional wells. Assumes 15 days at 12 hours operation per day. Emission calculated on basis of 4,500 HP engines, with fuel consumption of 250g/kWh.
		Emissions from pumping: Assumes 2 hours per operation and 15 operations per well. Emissions calculated on basis of 12,250 HP engines, with fuel consumption of 250g/kWh.
Broderick et al (2011)*	49 to 74	**Emissions from drilling:** Horizontal drilling of 1,000 – 1,500 metres. Vertical drilling is excluded from the estimate. Fuel use of 18.6 litres of diesel per metre drilled, which equates to an emission factor of 49kgCO2/m. Diesel emission factors of 2.64 kg CO_2/litre.
	295	**Emissions from pumping:** Based on average fuel usage from hydraulic fracturing on a horizontally drilled well in the Marcellus Shale. Assumes total fuel use of 109,777 litres of diesel fuel per well. Diesel emission factors of 2.64 kg CO_2/litre.

Notes: * Estimate for Marcellus Shale used for consistency with other studies.

With the exception of the Broderick et al (2011) study the estimates of emissions from drilling and pumping are of a similar order. The estimates from Santoro et al (2011) are within the range provided by Jiang et al (2011). The estimates from Stephenson et al (2011) are just below the lower range provided by Jiang et al (2011). The range in the estimates appears to be driven by the assumptions relating to the HP[5] and time required for drilling and pumping (hours).

The estimate from Broderick et al (2011) is lower than the other estimates, particularly for drilling. This can, in part, be explained by methodological differences. For example, Broderick et al (2011) only look at additional impacts so only included horizontal drilling and not vertical drilling. However, even allowing for this adjustment, the estimates appear a little low in comparison with the other estimates.

[5] 1HP = 746 watts

All estimates assume the equipment is diesel fuelled, so the GHG emissions are dominated by CO_2 from combustion.

3.3.2.3 *Uncertainties and data gaps*

The main uncertainty relates to what should be assumed in terms of a typical depth of well and the lateral length. Clearly the emissions from energy use in drilling will relate directly to these assumptions. Assumptions with respect to the drilling effort required, which may in turn relate to the geological characteristics (e.g. the strength of the shale formation), and design of the well pad (e.g. number of wells per pad) may also be important.

3.3.2.4 *Applicability of estimates to the EU*

The approach used to estimate the results above are applicable to the EU. However, the results themselves should be adjusted to reflect European shale gas fields.

3.3.3 Energy use in transportation

3.3.3.1 *Emission sources*

Hydraulic fracturing consumes large quantities of water (as described in Section 2.3.1.3), sand and chemicals for the proppant fluids. Transportation of the materials will be associated with GHG emissions from vehicle movements, assuming current vehicle technologies, and conventional transport fuels.

The fuel consumed in the transportation of the water and chemicals, and the associated emissions, will depend on the quantities of materials that are required and the distances that the materials need to be moved. These characteristics are site specific in nature. For example, in some locations operators may be licensed to abstract water directly from surface or ground water sources, but at other sites the water needs to be delivered by tanker truck or pipeline.

3.3.3.2 *Emission estimates*

In Table 5 existing estimates of the emissions from the transport of water and chemicals are compared.

Table 5: Existing estimates of emissions associated with transport of materials

Source	Emissions estimate (per well) (tCO_2eq)	Relevant assumptions and methodology
Jiang et al (2011)	64	Assumed water use of 9,000 – 27,240 m^3 [6] per well for fracturing, and 454 m^3 for drilling. Original water source 50% surface water and 50% water treatment plant. Water transported by truck from a local public water system 8 km – 16 km (5-10 miles) from the site. Assume a recycling rate for drilling mud of 85%. The estimated truckloads for taking water to the sites, and waste water from the site is 315,671 kg per km[7] (560 ton-mile per) well. Trucking load is 35,513,003 kg per km (63,000 ton-mile) for transport of fracturing water to the site, and 140,924,615 kg per km (250,000 ton-mile) for transportation of waste fluid. Uses lifecycle emission factor of 0.094 gCO_2eq/kJ.
Santoro et al (2011)	475	Assumes 321 km (200 miles) per truckload for drilling and completion equipment and an average of 201 km (125 miles /per truckload) for water chemicals and wastes. Assumes 280 truckloads for drilling and completion equipment and 1,069 truckloads for fresh water, chemicals and wastes. Truckloads are doubled for round trips and 50% load factor assumed. Emission factor of 0.455 litres per km[8] (0.161 gallons / mile) for diesel trucks. Assumes water use of 22,700m^3 per well for hydraulic fracturing. 40% of water brought to well is assumed to be recycled, so water and waste truckloads reduced according
Broderick et al (2011)	38 to 59	Assumes 60 km round trip. Assumes 485 to 750 truck visits per well (of which 90% attributed to fracturing) for water deliveries. Assumes a water volume of 9,000 m^3 to 29,000 m^3 per well. HGV emission factor of 983g CO_2/km.
Stephenson et al (2011)	224	Analysis based on the assumption of 25,331 km (15,740 miles) to 37,079 km (23,040 truck miles) for a 1 well project. Assumes 18,160 m^3 of water per well, and that 50% of the water is sent for treatment. Water transported by truck with a round trip distance of 241 km (150 miles) by road.

[6] 1 Imperial gallon = 0.00454 cubic metres
[7] 1 short ton per mile = 563.698463 kilograms per kilometre
[8] 1 Imperial gallon per mile = 2.82481053 litres per kilometre

Estimated emissions from transportation are strongly influenced by the assumed mass of material transported and the transport distance. The volumes of water required for the hydraulic fracturing process, and the location of the water supplies and waste water disposal facilities, are therefore key determinants. The assumed level of water re-use is also important.

The volume of water required per well, assuming multiple fracturing events, are very similar in each of the studies. Likewise the studies assumed water transport by truck. However the emissions estimates from Santoro et al (2011) are a factor of 7 - 10 times greater than those made in Jiang et al (2011) and Broderick et al (2011). The estimate from Stephenson et al (2011) falls in between. The difference in estimates appears to be mostly explained by the transport distance assumed and the level of water re-use.

3.3.3.3 *Uncertainties and data gaps*

The main uncertainties relate to the volume of water required, the source of the water used, and the transportation method. These factors will all be site specific.

3.3.3.4 *Applicability of estimates to the EU*

Due to the site specific nature of these emissions there may be significant differences, for example, in the distances required to collect water and the availability and regulations concerning the use of ground water on site. Caution will therefore be needed in extrapolating U.S. data to the European context where the availability and location of water will be different (and Member State regulations covering extraction may be different).

3.3.4 Emissions associated with resource use

3.3.4.1 *Emission sources*

Emissions may also be associated with the material used in the hydraulic fracturing process and as part of the site preparation. These emissions are additional to those associated with transportation. Energy may be consumed, or process related GHG emissions released, as part of the production of the chemicals used in the hydraulic fracturing / proppant fluid. In addition the production of steel and cement used at the site will be associated with emissions of GHGs, having an embedded CO_2 content.

3.3.4.2 *Emission estimates*

In Table 6 existing estimates of the emissions associated with materials used in the construction of the well pad, and production of material for the hydraulic fracturing, are compared.

Table 6: Existing estimates of emissions associated with resource use

Source	Emissions estimate (per well) (tCO_2eq)	Relevant assumptions and methodology
Jiang et al (2011)	100 - 300	Production of hydraulic fracturing fluid (e.g. chemicals, sand) and drilling mud. Detailed cost estimate used to inform an EIO-LCA model.
Santoro et al (2011)	1,188	Resource consumption: Includes steel, cement, chemicals, gravel and asphalt production. These materials are used for upgrading local roads, for the well casing and in the fracturing fluid.

Each of the studies has used a different methodology to assess resource use. This, in part, explains the difference in the results. The Santoro et al (2011) study includes emissions associated with the material used in the construction of the well pad. These emissions are captured in the Jiang et al (2011) study, as part of the site preparation step, using an extended Input-Output (EIO) methodology. It has not been possible to further breakdown these estimates to make a more equal comparison. However, the larger emissions estimate from Santaro et al (2011) for resource use is likely to be compensated a little by the larger emissions estimate from Jiang et al (2011) in the site preparation step.

Broderick et al (2011) omit an estimate of the emissions from resource use in their study on the grounds that it is difficult to estimate the additional impacts (which is the scope of their study) of shale gas developments from conventional wells, and that emissions from the chemicals used in the fracturing fluid are difficult to ascertain.

3.3.5 Treatment of the wastewater

3.3.5.1 *Emission sources*

Hydraulic fracturing produces much larger quantities of waste water than conventional gas wells. If included within the boundary of the LCA then emissions will arise from the treatment of waste water. These emissions are in addition to the transportation of the waste water, as described above.

3.3.5.2 *Emission estimates*

A summary of the main results from studies that have estimated the emissions arising from waste water treatment and the key assumptions is provided below.

Table 7: Existing estimates of emissions associated with treatment of waste water

Source	Emissions estimate (per well) (tCO_2eq)	Relevant assumptions and methodology
Jiang et al (2011)	300	Assumes the waste water will be disposed of via deep well injection. 15% of the 454 m^3 of water used for drilling, and 20% of the water used for hydraulic fracturing. Emissions estimated using EIO - LCA approach based on the cost of treatment and emissions associated with "support activities for oil and gas".
Broderick et al (2011)	0.3 to 9.4	Based on 15% – 80% recovery of 9,000 – 29,000 m^3 [9] of water. Treatment emission factor of 0.406 tCO_2/Ml treated.

For the two studies that estimated the emissions associated with waste water treatment the variation in the estimates is significant, with the Jiang et al (2011) study estimating emissions of the order of 30 times greater than those estimated by Broderick et al (2011). This difference can be explained by the use of different methodological approaches. The Broderick et al (2011) study used an emission factor that was based on the CO_2 emissions associated with waste water treatment in the UK, as reported by the water industry. In the Jiang et al (2011) study, emissions were estimated based on cost data, and the estimated emissions from 'support activities for oil and gas'. It is not clear what the scope of these support activities is and therefore how comparable the estimates are with the Broderick et al (2011) study.

Stephenson et al (2011) also included an estimate for the energy use associated with wastewater treatment, based upon an energy intensive reverse osmosis and evaporation or freeze–thaw evaporation technology. However, the value reported for the estimated energy use per well does not reconcile with estimated energy use for the treatment process that is quoted in the same paper. It has therefore not been included in the table above. However, even with this uncertainty, the estimated energy use appears closer to that implied in the estimate by Broderick et al (2011), rather than the estimate by Jiang et al (2011).

3.3.5.3 *Uncertainties and data gaps*

The volume of water required, the characteristics of the waste water and its associated treatment needs, the level of water reuse and the route of waste water disposal are all important parameters

[9] 1 litre = 0.001 cubic metres

driving emissions from this sub-step. The emissions assessment methodology is also important, particularly where emissions factors for waste water treatment are limited.

3.3.5.4 *Applicability of estimates to the EU*

The methodology is applicable to the EU context but needs to reflect current practice in the EU with respect to waste water treatment.

3.3.6 Well completion

3.3.6.1 *Emission sources*

Upon completion of hydraulic fracturing a combination of fracturing fluid and water is returned to the surface (flow back). The flow back contains a combination of water, sand, hydrocarbon liquids and natural gas. Where the water within the flow back fluid cannot be reused, typically the produced water, it requires disposal. The waste water may be disposed directly by injection into a used well, or transported for treatment at a waste water treatment facility.

Equipment used at an existing gas well under production conditions, including the piping, separator, and storage tanks, are not designed to handle this initial mixture of wet and abrasive fluid that comes to the surface. Standard practice has been to vent or flare the natural gas during this step, and direct the waste water into ponds or tanks (Armendariz, 2009). However, the temporary installation of equipment designed to handle the high initial flow of waste water, including gas - as part of a Reduced Emission Completions (see Section 2.3.1.4), is becoming more commonplace.. Reduced Emission Completions have been used by some companies to reduce methane emissions in Texas' Barnett Shale in the U.S. since 2004 (Devon Energy, 2012). In addition, the States of Colorado and Wyoming and the City of Fort Worth require the use of 'green completions' on all hydraulically fractured wells.

After some time, the mixture coming to the surface will be largely free of the water and sand, and then the well will be connected to the permanent gas collecting equipment (Armendariz, 2009).

Emissions from the well completion stage are short-term, typically occurring over a period of several days (U.S. EPA, 2011b). The level of emissions will depend upon the volumes of methane in the water flow back, the quantities of water flow back, the length of the flow back period and the management practices that are applied.

3.3.6.2 *Emission estimates*

Well completion is the most important step in the pre-production phase of shale gas exploitation, in terms of the associated GHG emissions. However, the level of emissions is highly uncertain and subject to current debate.

During the course of this study, the evidence base on the emissions associated with unconventional well completions has evolved. In particular, the U.S. EPA carried out a detailed review of these emissions as part of the derivation of a series of emission factors to underpin GHG reporting in the U.S. An emissions factor for gas well completions with hydraulic fracturing was published in 2011, for use in the 1990-2009 U.S. GHG inventory (U.S.EPA, 2011b). Following further consultation of these factors, and additional research, the emission factors were updated in 2012 (See box below).

In the intervening period, separate estimates have been published by other authors. Some of the main estimates are summarised below. This is then followed by a discussion of the latest U.S. EPA (2012b) analysis, which included a review of reported estimates from a wide range of sources, and therefore represents the most comprehensive examination of emissions from well completion.

The estimated gas release rate during the well completions stage, as used in a number of published studies, is provided in Table 8. A brief description of the basis for the estimates is also provided. Since the assumed management practices will influence the net release of emissions, these have been separated out and where possible the emissions are presented on an unmitigated basis. In practice, this may not represent the actual emissions from the well, since mitigation measures such as Reduced Emissions Completions, may have been employed.

It is also important to note that the estimates are not restricted to shale gas formations in all cases, with other unconventional gas formations (tight gas, coal bed methane) also taken into account in some of the estimates.

Table 8: Existing estimates of emissions associated with flow back

	Gas release rate (thousand m^3)	Unmitigated emissions (t CO_{2eq})	Approach
EPA (2011b)	20 to 560 (257 average)	3,443	Data from four industry presentations at a technology transfer workshops (green completions). Together the presentations represented data from over 1,000 well completions, for a range of formation types, with hydraulic fracturing. For each data source, EPA calculated the average gas release per gas well completion. The four data sources were arithmetically averaged to determine the final emission factor for gas well completions with hydraulic fracturing.
Howarth et al (2011)	140 to 6,800 (2,034 average)	27,247	Data on methane capture for four site (all emissions assumed to be vented in study), and the projected releases for the fifth (and largest) site.
URS (2012)	10 to 32 (21 average)	281	Calculated gas leakage (using EPA 2011 calculation methodology) during the completion of 98 (shale gas or tight sand) new gas wells from data provided by 5 (self-selected) companies. Average emissions were calculated by company and by shale gas basin. Only non-green completed wells were included in the sample.
Jiang et al (2011)	39 to 1,508 (603 average)	8,078	Release per flow back event, based on a modelled release and flaring rate.

Note: Converting these weighted-average factors to a mass basis, assuming a gas density of 0.68 kg/m3 and methane content of the vented gas to be 78.8% mole fraction. Converting to CO_2 equivalents using GWP (100 years) of 25.

Table 8 illustrates the potentially large range in the published estimates of emissions from unconventional gas well completions. The U.S. EPA (2012b) suggests that geology, technology and operating conditions are important factors which explain the high degree of variability in gas release rates. It is also important to note that different calculation methodologies may also have been applied in the results presented above.

One of the most widely quoted estimates is that derived by Howarth et al (2011), largely because of the overall conclusion that was drawn by the authors from the study in relation to the comparative emissions between shale gas and coal. Howarth et al (2011) concluded that shale gas has a much larger GHG (greenhouse gas) footprint than conventional natural gas, oil, or coal when used to generate heat and viewed over the time scale of 20 years.

The Howarth et al (2011) estimate was based on information on five unconventional gas sites. Two of the sites were shale gas wells, and three were tight gas. For four of the sites the gas release rate was based on data from sites that had employed reduced emission completion technologies (RECs), so the gas release rates were essentially estimated from gas capture rates. The estimate for the fifth site at Haynesville, and the largest of all five estimates, was based upon gas flow rates data for 10 well tests. The use of the Haynesville data has been criticised by some authors. Cathles et al (2011) argue that the assumption by Howarth et al (2011), that the gas flow rate data can be assumed to represent to the gas venting rates during the well completion, is incompatible with the basic physics of gas production and the economic incentives of gas production. Cathles et al (2011) claim that because initial production is the highest flow achievable, and flow back occurs when the well still contains substantial water, flow back gas recoveries cannot exceed initial production recoveries as assumed by Howarth et al (2011) for the Haynesville site. It is also argued that the volumes of gas vented by this site represent $1,000,000 worth of gas and present a fire / explosion hazard that no company would countenance (Cathles et al, 2011). Further criticism is made by IHS (2011), whose report was cited by Howarth as the source of the Haynesville data. IHS (2011) state that Howarth made an “improper calculation of the average of the individual well flow rates” and an “improper attribution of the (improperly calculated) average flow rates from all the wells as occurring during flow-back operations”. More specifically, the average flow rate stated in the Howarth study was based upon an average of eleven well tests. However, this included the double counting of data for the most prolific well, which increased the calculated average. In addition, only one of the ten wells reported was measured during flow-back. The others were measured while the wells were being completed (capped and connected to pipelines).

The release rates published in Jiang et al (2011) are lower than those from the Howarth et al (2011) study but are not based on actual site data. Instead a modelling approach is used to estimate the release rate, which in part explains the large variations in emissions, even though it represents a single site.

The estimates presented in URS (2012), which was a report prepared for America’s Natural Gas Alliance (ANGA) and the American Exploration and Petroleum Council (AXPC), are much lower than the other sources. This source captures industry data from 98 new wells that were non-green completed (i.e. completions without Reduced Emission Completions). The emissions were calculated by URS (2012) using the U.S. EPAs calculation methodology. The authors concluded that the emission factor quoted in U.S. EPA (2011b) was potentially overestimated by 1200%. However, in reviewing the URS (2012) results, the U.S. EPA (2012b) found a miscalculation in the analysis. Correcting this error, the U.S. EPA (2012b) calculated an emission factor of 1,400 m^3 (50,000 Mcf), which is a factor of 6,400% greater than the value reported in the original URS (2012) study[10].

Derivation of d*efault factors for Unconventional Well Completions* emission factors in the latest *U.S. EPA GHG Reporting Protocol*

The U.S. EPA has compiled a series of GHG estimation methodology and reporting protocols for operators to use as guidance to underpin GHG reporting under new mandatory reporting systems in the U.S.; operators in the oil and gas sector must start to report their GHG emission estimates to the U.S. EPA from the year 2010 onwards, under the new mandatory reporting rule.

The text in the U.S. EPA guidance (Appendix B) that outlines the process of deriving the factors is summarised below:

- The U.S. EPA derives a series of emission factors for unconventional well completions based on data from eleven U.S. gas industry studies; the studies include well completion emission estimates from a number of different geological formation types (shale, tight gas, coal bed methane) and present emission estimates for unmitigated well completions and reduced well completions;
- The analysis includes a critical review of all of the industry sources and identifies where submissions by industry are evidently incorrect in their application of the (agreed) U.S. EPA emission estimation equations for well completions;
- The U.S. EPA document presents five different approaches to deriving an aggregate emission factor from the industry source data: weighted average by well completion from all eleven studies

[10] Given this uncertainty, EPA (2012) performed the analyses of emission factors both with (using the URS-calculated values per completion, averaged to 734 Mcf as noted above) and without the URS emissions estimates.

(across all formation types), un-weighted average by data source, weighted average by well completion by formation type (shale, tight gas and coal bed methane), weighted average by well completion across all formation types using total national data on well completions by type (i.e. to represent the U.S. data on numbers of well completions by formation type rather than just from the data available within the eleven studies), and a weighted average across tight gas and shale gas formation types (as these show similar levels of emissions);

- The U.S. EPA then assessed the various outcomes from these approaches as derived a "final emission factor" for all unconventional gas well completions to be 9,000 Mcf per completion (254,700 m^3), whilst the factor derived specifically for tight gas and shale gas formations (discounting the much lower estimates from coal bed methane) was 11,025 Mcf (312,007.5 m^3) per completion.

The weighted average factor for tight gas and shale gas formations of 11,025 Mcf (312,007.5 m^3) is regarded by the study team as the "best" factor to use as a central estimate within this study, but it must be noted that there is a high degree of reporting variability and uncertainty from across the industry studies. This factor equates to approximately 312,000 m3 per completion (unmitigated), or 167 tCH_4 (3,503 t CO_2eq).

In the existing estimates of emissions from well completion in the preparation of a technical support document for the oil and gas industry's reporting of GHG emissions (U.S. EPA, 2012b). The document provides further details on the industry estimates used in the draft technical support document (U.S EPA, 2011b), as well as reviewing additional evidence supplied by industry and environmental organisations as part of the consultation on the new Performance Standards that the document supports. Analysis was carried out of different ways to combine the data sets, and the associated emission factors. In addition, a statistical analysis was carried out to explore the variability in the emissions data. This level of uncertainty is highlighted by Pétron et al (2012), who applied dispersion modelling analysis techniques to estimate overall methane loss to the atmosphere around a U.S. shale gas field and estimated emissions at a level double that estimated by the U.S. EPA methodology.

As a result of this analysis the U.S. EPA recommended a default emission factor for emissions of gas per unconventional gas well completion of 9,000 Mcf (thousand cubic feet) (254,700 m^3) per completion. Further details on the derivation of the default factor is summarised in the box above.

A further important consideration is the management practices that are used for managing the gases in the flow back liquid. In the estimates provided above the emissions were assumed to be unmitigated. However, in practice flow back gases will not be simply vented, with flaring of emissions and gas capture techniques employed. This, of course, has an important influence on the results of the LCA.

Evidence from the U.S. EPA Gas Star programme suggests that Reduced Emissions Completions may achieve mitigation of fugitive / vented methane from well completions of around 90%. Applying the 90% reduction estimate to the recalculated U.S. EPA factor for shale and tight gas formations (i.e. 11,025 Mcf per completion, 312,007.5 m^3) provides an emission factor of Reduced Emission Completions of 31,000 m^3 per reduced emission completion, or 350 tCO_2eq per completion.

3.3.6.3 *Uncertainties and data gaps*

The main uncertainties relate to the unmitigated gas release rates and also the management practices that are typically employed at the production sites. The former is related to the characteristics of the particular site, and is clearly an area where there is a large amount of uncertainty, which may in part relate to the natural level of variability. In the case of management practices this is less of an issue as the management practices can be influenced by policies and regulations.

3.3.6.4 *Applicability of estimates to the EU*

From a technical perspective the results are considered to be applicable to emissions that may arise from hydraulic fracturing activities in the EU. However, the actual emissions are strongly related to the management practices that are in place. It is therefore worth considering how typical management practices in the EU may differ from those in the U.S.

3.4 Production and Processing Stage

This stage includes the processing stage which is not discretely separated from the production in much of the literature.

3.4.1 Sources of emissions

During this stage the most significant GHG emissions are from the compressors, dehydration equipment and some chemical processing. Additional GHG emissions could be fugitive methane in the form of natural gas migration away from a gas well in case well integrity has been compromised, especially through failure of the surface casing or the cement used to cap the well. However, this issue is not specific to unconventional gas and such emissions need to be prevented for water protection and health and safety reasons.

3.4.2 Technologies

The main technologies used in this process are the dehydration equipment, pumps and compressors. This is standard equipment that is used for conventional gas production.

3.4.3 Estimates of emissions

The New York State Department Environmental Conservation (NYSDEC, 2011) report provides the most detailed estimates of the total emissions from the production phase of the Marcellus shale deposits. These are summarised in Table 9:

Table 9: Typical emission from the production stage

	Methane (CH_4) (tonnes)	Carbon Dioxide (CO_2) (tonnes)
First full year in which drilling commenced		
- single vertical well	212	5,346
- single horizontal well	207	5,071
- four well pad	321	3,524
Post first year annual emissions		
- single vertical / horizontal well	221	5,591
- four well pad	512	5,608

Notes: emissions converted to tonnes assuming 1 short ton = 0.907 tonnes

The vast majority of the emissions arise from the compressors but there are also significant methane emissions from the dehydration operations. Table 10 summarises the key emission data for the post first year annual well production for a single vertical or horizontal well (summarising the results from NYSDEC, 2011).

Table 10: Typical emissions from activities used during the production stage

Activity	Methane (CH_4) (tonnes)	Carbon Dioxide (CO_2) (tonnes)
Well head	Negligible	Not Applicable
Compressor	116	5,591
Dehydration equipment	97	3
Other equipment	8	Negligible
Total	**221**	**5,591**

Notes: emissions converted to tonnes assuming 1 short ton = 0.907 tonnes.

3.4.4 Uncertainties and data gaps

The figures quoted above are not directly comparable since they are not associated with a specific production rate(s) which, because the Marcellus production is still new, are subject to considerable uncertainty.

3.4.5 Applicability to EU

The equipment used in shale gas E&P is similar to that used in conventional gas E&P. Therefore the equipment being used during shale gas E&P is likely to be applicable to the EU.

3.4.6 Discussion

Since most of the emissions in this stage arise from equipment which would be used for conventional gas production, while there are significant emissions during the production stage, they are not significantly different from conventional gas production. Howarth et al (2011) note that the emissions from routine venting and leaks during the production stage are between 0.3 to 1.9% of the methane produced from a well for both conventional gas and shale gas.

3.5 Transportation and distribution

Methane (CH_4) emissions, due to leakage, during this stage are a significant proportion of the total lifecycle emissions. However once the gas has entered the distribution pipelines leakage rates, and therefore emissions, are the same whether the gas has been supplied from conventional or shale gas reserves. For example Howarth et al (2011) estimate that for both sources the fugitive emissions of methane are between 1.4% and 3.6% of the methane produced over the lifecycle of a well. However Stephenson et al (2011) estimate that losses would be lower, suggesting based in the 2009 API compendium that 0.066% of gas is lost to fugitive emissions over 1440 km (which was taken as a typical distance for transmission to a power station in the U.S). The report notes that data from the U.S. EPA (2011) inventory report suggests that over the whole industry this could be higher, with losses from transmission and storage accounting for roughly 0.52% of total gas production. However even this value is much lower than the lower limit suggested by Howarth et al (2011).

Stephenson et al (2011) also estimate that about 1.4% of gas would be consumed by compressor stations along the pipeline, again assuming a distance of 1440 km.

3.6 Well plugging and abandonment

Data for this stage is sparse. The main source of emissions during the abandonment phase itself will result from the industrial processes required to pour concrete to seal the well. Following this, fugitive emissions may occur if the well integrity is compromised. The literature review suggests that there is growing awareness in the U.S. concerning the abandonment of on-shore wells.

3.7 Summary

The life cycle emissions estimated in the studies reviewed above, plus those of Skone (2011) and Lechtenbohmer (2011), are summarised in Table 11. The table sets out values for the base cases assumed, plus where numerical values are available, the results of sensitivity analysis. Results are presented for 100 year GWP for methane ($CH_{4)}$ and nitrous oxide (N_2O).

The different boundaries assumed in the studies need to be taken into account in comparing results from the studies: Stephenson et al (2011) did not estimate emissions from the construction phase; and Broderick et al (2011) has only examined emissions which are additional to those from conventional gas extraction, so has not examined well construction, and has only considered the horizontal element of drilling. Howarth et al (2011) only included fugitive emissions, so the results presented have been combined with those from Santaro et al (2011), as suggested in the Howarth et al (2011) paper in order to capture the full range of emission impacts. One further factor to bear in mind is that Howarth et al (2011) has used a 100 year GWP for methane of 33 in calculating the CO_2eq of methane emissions, whereas all of the other studies have used the GWP for methane of 25, as set out in the IPCC Fourth Assessment Report (2007). Howarth et al (2011) justifies the use of this higher GWP on the basis that more recent modelling (Shindell et al, 2009 as referenced in Howarth et al, 2011) which better accounts for the interaction of methane with aerosols. However as Broderick et al (2011) note, these processes are not yet well supported by a robust set of computer models.

Emissions from pre-production stages are compared in Figure 4. It is clear that the greatest contribution to emissions comes from the well completion stage, whether this is assumed to happen only once at the beginning of the production cycle, or several times as the well is worked over (as assumed in Skone et al, 2011). Estimates of emissions from this stage vary significantly between the studies, with that from Howarth et al (2011) being considerably higher than in the other studies, even after allowing for the use of a higher GWP, which will increase the methane contribution to total emissions by about a third compared to the other studies. Assumptions about the type of completion also have an influence, as can be seen from the Stephenson et al (2011) values, where the base case assumes 51% of the gas produced during flow back (that which is contained within the flow back liquid) is flared, compared to 98% in the low case and 0% in the high case where all the gas is vented. Similarly the high case in Broderick et al (2011) assumes that all methane produced during flow back is vented. The range in Broderick et al (2011) is in fact based on the other studies shown in Figure 4, but in the case of Howarth et al (2011) the value has been adjusted to a GWP of 25. Even so, this value (at 15.3 g CO_2eq/MJ) is still considerably higher than values reported in the other studies (0.3 to 7.1 g CO_2eq/MJ).

The second most significant source in this stage is drilling and hydraulic fracturing, where emissions (which range from 0.6 to 2.8 g CO_2 e/MJ (for the base cases). The emissions arise from a range of energy using source including: powering drilling equipment; transport of water to site and waste water away from site; processes to supply water and treat waste water, and ‘embedded carbon’ in the proppant and chemicals used in the hydraulic fracturing fluid. The relative importance of these activities varies from study to study, reflecting both site characteristics (e.g. transport distances), and methodological choices (e.g. approach to estimating emissions from waste water treatment).

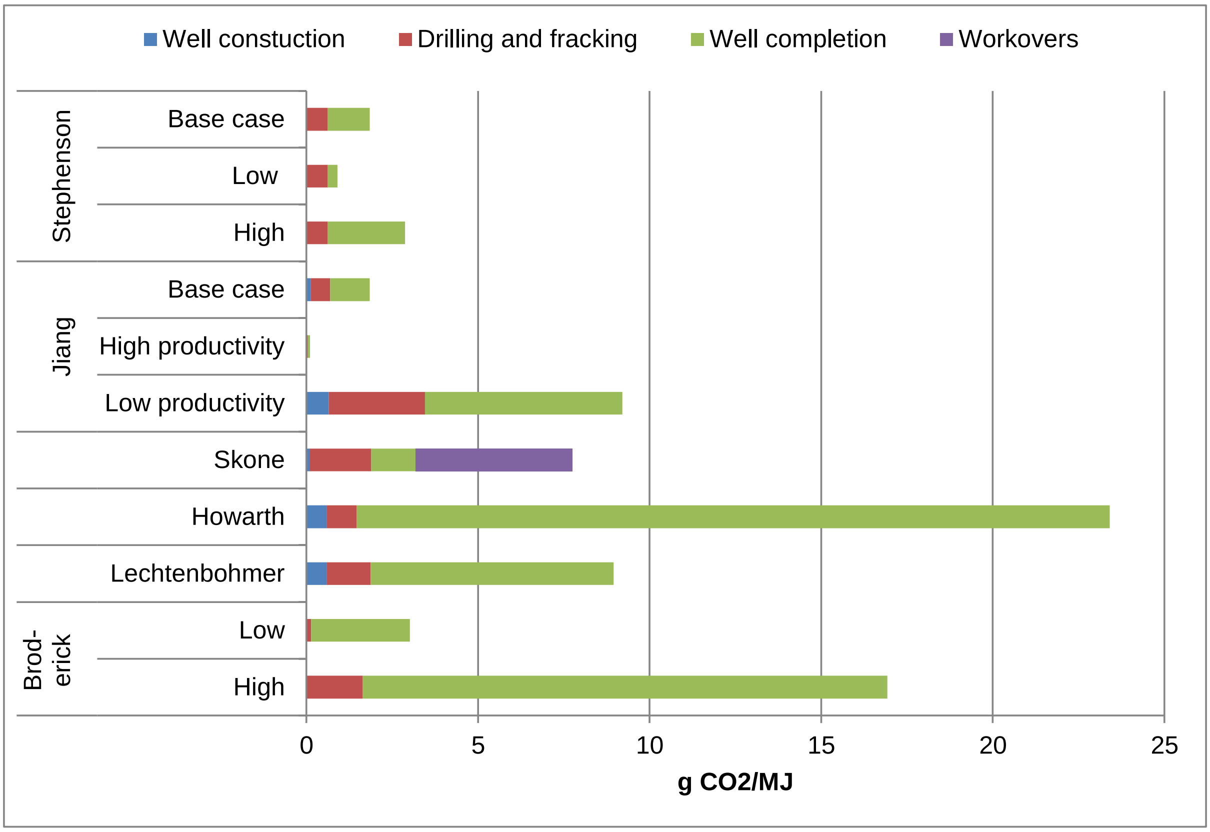
Emissions from land clearing, site preparation and construction of well pad, access roads and well casings, including emissions associated with transport and production of materials are smaller (0.1 to 0.6 g CO_2eq/MJ for the base cases).

The importance of assumptions about the productivity of the well are shown clearly in the results from Jiang et al (2011), and this is to be expected, as emissions from this preproduction stage are generally independent of lifetime gas production, so their contribution per MJ of gas declines directly as gas production increases.

Similarly the results from Skone et al (2011) indicate the importance of assumptions about the emissions associated with re-fracturing, as reflected in the relative contribution from workovers[11], at 60% of total emissions estimated.

[11] See glossary for technical terms; workovers are a repair operations on a producing well to restore or increase production. This may involve repeat hydraulic fracturing to re-stimulate gas flow from the well.

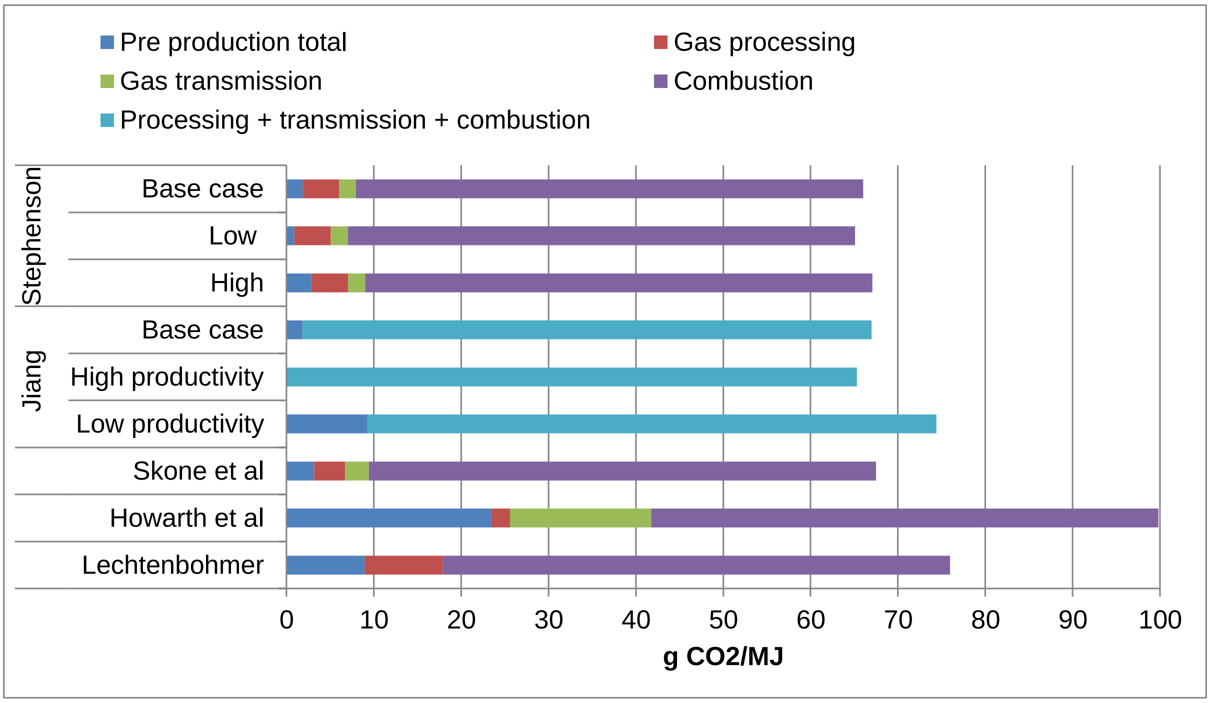
Figure 4: Life cycle emissions from pre-production stages (gCO_2 eq/MJ gas combusted, using 100 year GWPs for CH4 and N2O of the IPCC Fourth Assessment Report)



Notes: All studies assume a 100 year GWP for methane of 25 with exception of Howarth which uses 33. Studies have differences in scope and assessment methodology which limits comparability. Broderick et al (2011) only includes additional impacts of shale gas over conventional gas. Stephenson excludes well construction impacts. The results from Howarth et al (2011) only include fugitive releases, so have been combined with those from Santaro et al (2011) (on non fugitive emissions) as suggested in the Howarth et al (2011) paper in order to capture full range of impacts.

Figure 5 compares total life cycle emissions from the combustion of shale gas, for studies which have also examined emissions associated with gas treatment and gas transmission. For studies where combustion was not estimated; Skone et al (2011); Howarth et al (2011) and Lechtenbohmer (2011) a value of 58.1 g CO_2eq/MJ from Stephenson et al (2011) has been assumed. A breakdown of emissions between gas treatment, transmission and combustion is not available from Jiang et al (2011), so these are shown only in total in the Figure 5. In all cases, except Howarth et al (2011), the emissions from the pre-production stage, where emissions will differ from conventional natural gas production, are 3% to 12% of total life cycle emissions. Where flaring rates for gas produced during well completion are high or the well has a very high productivity, then the contribution may be reduced to 1.4% or less. In the case of Howarth et al (2011), the contribution of the pre-production stage to overall life cycle emissions is 23%. This is because of the high methane emissions assumed during well completion and higher GWP factor used for methane. Fugitive losses of methane during pipeline transmission of the gas are also assumed to be higher in Howarth et al (2011) than other studies, which together with the higher GWP assumed, means that the estimated contribution from transmissions is much higher in the Howarth et al (2011) study than other studies leading to a much higher overall emissions of 100 g CO_2eq /MJ of gas compared to values of 65 to 76 g CO_2eq/MJ for the other studies.

Figure 5: Total life cycle emissions for shale gas (CO_2 eq/MJ gas combusted using 100 year GWPs for CH4 and N2O of the IPCC Fourth Assessment Report)



Notes: All studies assume a 100 year GWP for methane of 25 with exception of Howarth et al (2011) which uses 33. Studies have differences in scope and assessment methodology which limits comparability. Broderick et al (2011) only includes additional impacts of shale gas over conventional gas. Stephenson et al (2011) excludes well construction impacts. The results from Howarth et al (2011) only include fugitive releases, so have been combined with those from Santaro et al (2011) (on non-fugitive emissions) - as suggested in the Howarth et al (2011) paper - in order to capture full range of impacts.

Table 11: Summary of life cycle emissions estimates for shale gas (g CO_2/MJ)

	Stephenson et al (2011)			Jiang et al (2011)			Skone et al (2011)	Howarth et al (2011)[1]	Lechten-bohmer (2011)	Broderick et al (2011)	
	Base case	Low	High	Base case	High product-ivity	Low product-ivity				Low	High
Well construction	Not estimated	Not estimated	Not estimated	0.1	0.0	0.7	0.1	0.6	0.6	Not estimated	Not estimated
Drilling and hydraulic fracturing	0.6	0.6	0.6	0.6	0.0	2.8	1.8	0.9	1.3	0.1	1.6
Well completion	1.2	0.3	2.3	1.2	0.1	5.8	1.3	21.9	7.1	2.9	15.3
Workovers							4.6				
Pre-production total	***1.8***	***0.9***	***2.9***	***1.8***	***0.1***	***9.2***	***7.8***	***23.4***	***9.0***	***3.0***	***16.9***
Gas processing	4.2	4.2	4.2				3.5	2.2	8.9		
Gas transmission	1.9	1.9	1.9				2.7	16.2			
Pre combustion total	***8.0***	***7.0***	***9.0***				***9.4***	***41.7***	***17.9***		
Combustion	58.1	58.1	58.1								
Overall lifecycle	***66.0***	***65.1***	***67.1***	***67.0***	***65.3***	***74.4***					

[1] Includes indirect emissions from Santaro et al (2011).

4 Best available techniques for reducing GHG emissions

4.1 Introduction

This chapter summarises and evaluates the available knowledge on shale gas extraction technologies and practices and the related GHG emissions.

As the most significant difference in GHG emissions from shale gas production compared to conventional gas production arises in the pre-production phase the analysis is focussed on this process. However we note that, in particular for the production phase, there are significant emissions from conventional equipment. For example pumps and compressors, and will note that improved technologies for these that could contribute to an overall reduction in GHG emissions from shale gas production. Reductions from the emissions due to leakage from gas distribution pipes will require improvements to the gas supply infrastructure off-site and, except for new pipes laid to connect the well head to the gathering, treatment and distribution system are likely to be outside the scope of the shale gas producers.

The U.S. EPA's Natural Gas STAR programme is a voluntary partnership which encourages oil and natural gas companies to adopt cost effective technologies and practices to both improve operational efficiency and reduce methane emissions. The U.S. EPA has recently finalised New Source Performance Standards (NSPS) for the Oil and Natural gas sector (U.S. EPA, 2012a). The U.S. EPA proposal for NSPS (U.S. EPA, 2011b) and the background technical support documents for the rule (U.S. EPA, 2012c) and the proposal (U.S. EPA, 2012b) provide a review of best practice which could be applied in the oil and gas sector. In particular these provide best practises for: well completions and recompletions; pneumatic controllers; compressors; storage vessels and equipment leaks. The data in the next sections use this as a basis which is supplemented from other sources.

4.2 Pre-production

4.2.1 Site preparation

Appropriate site selection and preparation may reduce GHG emissions, and in particular $CO_{2,}$ from combustion emissions by reducing fuel consumption. Preparation of the well pad requires resources, for example to level the site, prepare well cellars and install impermeable membranes. Use of existing roads, water resources and other infrastructure can minimise such work and the associated emissions from their construction. Provision of on-site storage of water and hydraulic fracturing fluids is often achieved through use of mobile tanks but some sites install reservoirs or lagoons for water and drilling / hydraulic fracturing fluids, but these have to be removed and land restored on completion. Use of transportable tanks will generally require less site preparation but this will depend on the site and availability of water, quantity of generated materials and treatment facilities. Consideration of drilling and well completion requirements during site selection will avoid or minimise situations where combustion or recovery of flow back gas (or accidental releases) might be constrained by proximity to buildings or other amenity space.

The NYSDEC (2011) report suggests the following measures which could be included to reduce these emissions:

- Drilling as many wells as possible using one rig move;
- Optimising the well spacing for efficient recovery of natural gas;
- Planning for efficient rig and fracturing equipment moves from one pad to another.

Site selection may also be important in reducing transport emissions which could be further reduced by:

- Ensuring that personnel and equipment can be sourced locally;
- Identifying sources or materials locally (including water and sand used in the hydraulic fracturing process);
- Identifying local facilities to recycle, and dispose of waste products;
- Planning to reduce the number of vehicle journeys;
- Using efficient transport engines.

4.2.2 Drilling

As outlined in Section 3.2.2.1, during the drilling phase, a temporary drilling rig is brought to the well pad and erected on site. Energy for the drilling operation (and all ancillary support activities such as well pad lighting and crew housing) is provided by large, diesel-fired internal combustion engines. As mentioned previously this step of the process is the same for conventional and unconventional gas wells. Horizontal drilling is required for shale gas and may also be used for conventional gas (and oil). Drilling is not a significant source of methane emissions, but the drilling rig engines are a source of combustion-related pollutants such as nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), and unburned hydrocarbons (HC). Three-way catalytic oxidizers may be used on drilling rig engines to reduce non-CO_2 emissions. Use of gas engines or engines powered from the local electricity grid may also be possible if supplies are available at the site.

Appropriate well design and supervision, including choice and depth of casings, seals and monitoring are essential to assure safety, avoid gas / fluid migration and maintain well integrity during the drilling phase.

4.2.3 Hydraulic Fracturing

During this phase of the well development process, the wellbore is fractured as discussed in Section 1.2. As with the drilling phase, energy for the hydraulic fracturing operation is typically provided by diesel-fired internal combustion engines. However, the fracturing phase is generally over a shorter period than required to drill the wellbore, using flatbed-mounted engines up to 1000 HP capacity. Depending on the number of fracturing phases involved in stimulating the formation, this step may last from several days to several weeks. Carbon dioxide emissions during the fracturing phase are primarily a result of fuel combustion. Typically a well pad will include several wells and, after completion of the first well, gas is likely to be available at the site and use of gas engines may be possible if gas quality is suitable. Similarly, if a well has to be re-fractured at a later stage, then use of gas engines could be an alternative to diesel-fired engines.

4.2.4 Well completion and flow back

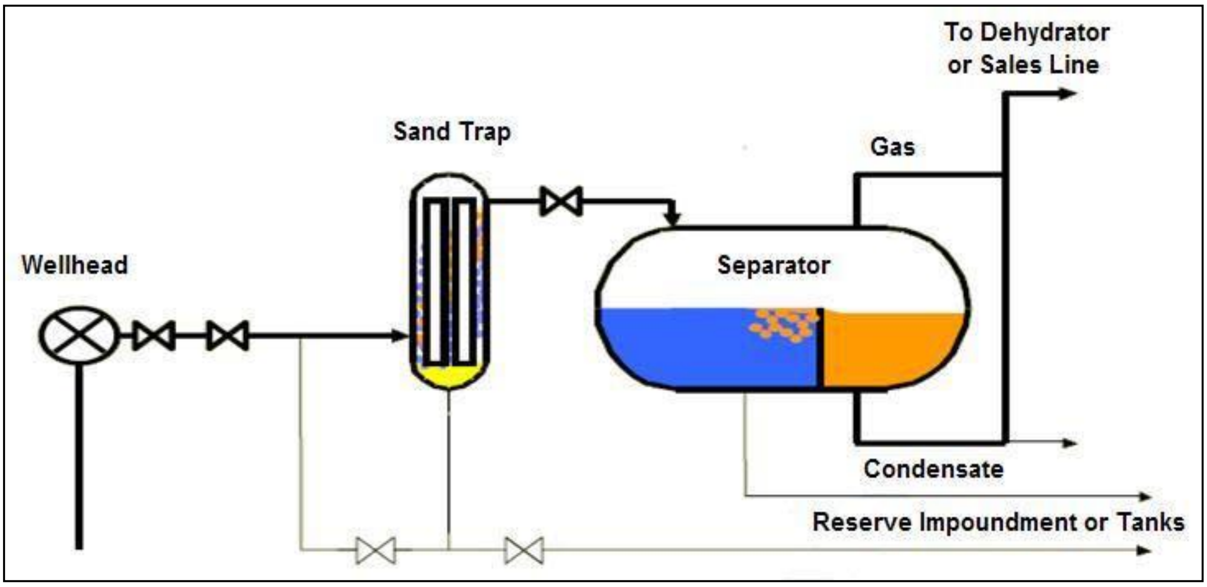
4.2.4.1 *Reduced emissions completions*

4.2.4.2 *Description*

Upon completion of the fracturing step the fracturing fluid mixture that returns to the well head will contain a combination of water (including produced water and waste water), sand, hydrocarbon liquids and natural gas (flowback fluid) (as outlined in Section 3.2.6.1 and Section 2.3.1.4). If it is not captured or used, the methane within the natural gas will be released into the atmosphere.

Methane emissions from the flow back / well completion step may be controlled through the use of reduced emission completions, or green completions, as shown in Figure 6 (U.S. EPA, 2011d).

Figure 6: Reduced Emissions Completion Equipment (U.S. EPA 2011d)



A reduced emission completion involves the temporary installation of equipment designed to handle the high initial flow of water, sand, and gas. A sand trap is used to remove the solids, and is followed by a three phase separator which separates the water from the condensate (liquid hydrocarbons) and gas. The gas is then sent to a sales pipeline (or to other processing facilities where needed). Where the pipeline infrastructure is not yet in place to receive saleable gas, the gas stream may be routed to suitable storage before treatment and transfer offsite or a temporary flare.

While not currently required in the U.S. at the national level, green completions have been used by some companies to reduce methane emissions in Texas' Barnett Shale since 2004 (Devon Energy, 2012). In addition, the States of Colorado and Wyoming and the City of Fort Worth require the use of green completions on hydraulically fractured wells. The U.S. EPA has recently finalised regulations that will require the use of reduced emission completions including the recovery of gas for sale on all new hydraulically fractured gas wells, as well as on re-fractured gas wells from 1 January 2015. Prior to this date completion will be by flaring or capture plus flaring. Green completions are not required for:

- new exploratory wells or wells used to define borders of a natural gas reservoir;
- hydraulically fractured low pressure wells (such as coal bed methane wells).

However emissions must be reduced using combustion unless combustion is a safety hazard or prohibited by local regulation.

4.2.4.2.1 Limitations

Limitations include:

- Availability of pipelines to transport the gas for sale or of equipment for other forms of natural gas utilisation (e.g. small scale power production).
- During the exploratory phase the sales pipelines may not have been constructed.
- Pressure of the produced gas.
- If pressure is too low then it may be difficult to displace the hydraulic fracturing fluid - compressed natural gas or inert gas may need to be pumped down the well to help displace the hydraulic fracturing fluid. Low pressure may limit effectiveness of any treatment stages (it may not be possible to produce sales or pipeline quality gas) and will limit the amount of gas that can be recovered into a storage vessel (without additional compression).
    - If the concentration of inert gases, such as CO_2 or N_2, is too high then it may not be possible to economically recover the natural gas and as above it may be necessary to flare the gas until the composition of the gas is acceptable. Furthermore, a source of continuous ignition may be required until the energy content of the gas is sufficient to sustain a flame.

4.2.4.2.2 Effectiveness

Emissions reductions vary depending on the specific characteristics of the well:

- Duration of completion;
- Number of fractured zones;
- Flow back pressure;
- Gas composition;
- Fracturing technology / technique.

U.S. EPA analysis assumes 90% of gas contained within flow back can be recovered (U.S. EPA, 2012b).

4.2.4.2.3 Cost

Illustrative costs are provided in U.S. EPA (2011c) and updated in U.S. EPA (2012b). For a typical completion estimated cost, including transport and installation of temporary equipment, is $33,237 (2008). This results in an average cost of $221 per ton of methane recovered. Against this the sales of the methane, with additional sales of liquid hydrocarbons from the condensate, provide a net saving of $1,543 per completion ($9.55 per tonne[12] of methane abated).

4.2.4.2.4 Secondary impacts

There are no secondary impacts. Secondary benefits include reduction in non-methane volatile organic compound (VOC) emissions and recovery of natural gas liquids.

4.2.4.3 *Completion Combustions (Flares)*

4.2.4.3.1 Description

Completion combustion devices are used to control VOCs in many industrial applications. They can be as simple as a pipe with a basic ignition source. Gas contained within flow back may or may not be combustible depending on the composition of inert gases and may therefore require the use of a continuous ignition source. These devices (pit flares) are not controlled and are not capable of being tested or monitored for efficiency.

4.2.4.3.2 Limitations

Due to the variable conditions during flow back there may not be a continuous supply of gas and so self-sustained flaring may not be possible. Furthermore the exposed flame may pose a fire hazard or other impacts in some situations, for example dry windy conditions and proximity to nearby occupied buildings. However such issues may be mitigated by appropriate management techniques including location of the well pad and design and location of the flare.

4.2.4.3.3 Effectiveness

The efficiency of combustion devices which can be used for exploratory wells, and also for development wells, is expected to be 95% on average during the completion / recompletion of the well.

4.2.4.3.4 Cost

U.S. EPA (2011c) state the average cost of flaring is estimated to be $3,523 per completion (2008 prices) providing cost of abatement of $20.93 per tonne methane and $145.60 per tonne VOC.

4.2.4.3.5 Secondary impacts

Flaring may cause:

- Noise and heat;
- Loss of visual amenity;
- Secondary pollutants including NOx, COx, SOx and smoke / particulates.

[12] All prices converted by a factor of 0.91 to convert price per ton (U.S.) to price per tonne (metric)

4.3 Production Stage

During the production stage emissions can occur from a number of sources including:

- Gas treatment (sweetening);
- Storage Tanks;
- Dehydration;
- Pneumatic Devices;
- Compressors.

Each of these emission sources, and methods available to minimize or control associated emissions, is discussed below.

4.3.1 Gas treatment (sweetening)

The processes used to remove CO_2, N_2 and sulphur compounds from shale gas are the same as used in conventional gas wells. It is anticipated that gas will not be treated at the wellhead or well pad (although this is possible) but would be brought to a central gathering and refining station to provide gas which is suitable for compression and transfer to the gas transmission infrastructure. Typically this will require reduction in moisture (dehydration), inert gases (CO_2, N_2) and might require separation of natural gas liquids and non-methane hydrocarbons, recovery of helium, reduction of hydrogen sulphide and mercury.

Where natural gas terminals / refineries are already in place (for conventional gas) this may be achieved by some initial processing of the gas at the field's gathering / compression to allow transport (by pipeline) to the terminal. In other instances, the gathering station will need to undertake treatment of gas to the national or regional transmission pipeline requirements. In the latter case, the installation may be considered to be a refinery and a regulated activity under Directive 2010/75/EU (IED Directive) and hence best available techniques would be applied.

4.3.2 Storage Tanks

4.3.2.1 *Description*

Storage tanks are used at natural gas wells to handle the produced water. Emissions from storage tanks occur from working losses (as the gas vapours in the head space of the tank are expelled as additional liquid enters the tank), breathing losses (due to changes in volatilization of hydrocarbons in the liquid due to diurnal temperature changes) and flashing losses. Flashing losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure to a vessel with lower pressure, allowing the gases to vaporize, or "flash" out of the liquid. These emissions may be controlled through the use of vapour recovery units (VRU's) (U.S. EPA, 2006a) and flares. Control of emissions from condensate storage tanks was included in the U.S. New Source Performance Standards (NSPS) (U.S. EPA, 2012a).

4.3.2.1.1 Limitations

The applicability of vapour recovery units is dependent on the availability of electrical supplies sufficient to power the compressor.

4.3.2.1.2 Effectiveness

VRU's or combustion units can reduce emissions from storage tanks by approximately 95%.

4.3.2.1.3 Cost

The cost of a VRU, including installation and commissioning, is estimated to be $98,186 with annual operating costs of $18,983 per year (U.S. EPA, 2011c).

The cost for a combustor, including installation and commissioning, is estimated to be $23,699 with annual operating costs of $8,909 per year (U.S. EPA, 2011c).

4.3.2.1.4 Secondary impact

The secondary impacts from VRU's are negligible.

The secondary impacts from combustion arise from the secondary pollutants including NO_2, CO_2, SOx and smoke / particulates.

4.3.3 Dehydration

4.3.3.1 *Description*

Glycol dehydrators are commonly used at natural gas well pads, compressor stations, and processing facilities to remove water from the gas stream prior to entering the sales line. Methane emissions may occur from glycol circulation pumps, gas strippers and the gas still column. In addition to methane, dehydrators are also a source of BTEX (benzene, toluene, ethylbenzene, and xylene). Dehydrator emissions are regulated in the U.S. under the National Emissions Standards for Hazardous Air Pollutants (NESHAP) program, which requires 95% control of emissions at larger sources through the use of vapour recovery units or flares (U.S. EPA, 2011c).

NYSDEC (2011) recommends replacing glycol dehydrators with desiccant dehydrators.

4.3.4 Pneumatic Devices

4.3.4.1 *Description*

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators and valve controllers. The U.S. EPA (2011c) estimated that approximately 400,000 of these devices are used in the production sector to control and monitor gas and liquid flows and levels in separators, storage tanks and dehydrators. By design these devices emit small quantities of natural gas on a continual basis (continuous bleed) or in short bursts (intermittent bleed).

The following techniques may be used to minimize methane emissions from pneumatic devices (U.S. EPA, 2011c and U.S. EPA 2006b):

- Replacement of high-bleed devices (those releasing over 0.168m^3 [13] of natural gas per hour) with low-bleed devices having similar performance capabilities;
- Installation of low-bleed retrofit kits on operating devices;
- Enhanced maintenance, cleaning and tuning, repairing / replacing leaking gaskets, tubing fittings and seals.

4.3.4.2 *Limitations*

Low-bleed devices may not be suitable for all applications, particularly where fast or precise control or process operation is required. These include processes where a slow response could result in damage to equipment.

4.3.4.3 *Effectiveness*

U.S. EPA (2011c) identifies average bleed methane emissions estimates for the natural gas production sector in the U.S. to be 6.50319 tonnes[10] per year. They also estimate that the emissions reductions by replacing high-bleed devices by low bleed devices would be 5.9862 tonnes[10] which suggests the effectiveness in reducing emissions of 90%.

4.3.4.4 *Cost*

The average cost of a low-bleed valve is quoted as \$2,553, compared to that of a high-bleed valve at \$2,388, i.e. a difference of \$165 per device. It is estimated that the sales value of methane saved is \$1,500 per year (U.S. EPA, 2011c).

4.3.4.5 *Secondary impacts*

There are no secondary impacts.

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[13] 1 cubic foot= 0.028 cubic metres

4.3.5 Compressors

4.3.5.1 *Description*

Natural gas compressors may be installed at a wellhead to assist in natural gas extraction during the later stages of well life to increase pressure from an individual well to a gathering station. Typically compressors will be located at gathering / processing stations to allow gas treatment and to enable export to the transmission pipeline. Two types of compressors can be used, centrifugal compressors and reciprocating compressors. These compressors are typically powered by natural gas-fired engines or turbines, which emit combustion by-products such as NO_x, CO, CO_2, and hydro carbons. In some urban oil and gas fields in the U.S. these compressors may be powered off of the local electrical grid, eliminating these local, combustion-related emissions. In addition to the combustion-related emissions, natural gas and methane may be emitted from wet seals in centrifugal compressors and from the rod packing seals of reciprocating compressors. The methane emissions from reciprocating compressors are significantly less than for centrifugal compressors. For centrifugal compressors the use of dry seals (rather than wet seals) can be used to mitigate the methane emissions (U.S. EPA, 2006c). For reciprocating compressors the emissions can be reduced by the periodic replacement of the rod packing systems on reciprocating compressors (U.S. EPA, 2006d).

4.3.6 Pipework and Equipment Leaks

4.3.6.1 *Description*

Leaks can occur from many potential sources at the well site, including pipework and equipment such as compressors and pneumatic devices. In addition, open ended lines and sampling connections may leak. Furthermore, corrosion of welded connections and flanges and valves may leak if not adequately maintained. Due to the large number of components this may build up to a significant source of emissions.

Corrective action depends upon an effective Leak Detection and Repair (LDAR) programme which includes:

- Identifying component;
- Leak definition;
- Monitoring components;
- Repairing components;
- Record keeping.

A number of leak detection methods are available for this purpose.

4.3.6.2 *Effectiveness*

The effectiveness is dependent on the frequency of monitoring leak definition, the frequency of leaks and promptness with which leaks are repaired. Comparison with the chemical and petroleum refining sectors suggests that the effectiveness varies from 45% to 96%.

4.3.6.3 *Secondary impacts*

There are no secondary impacts.

4.4 Well Plugging and Abandonment

4.4.1 Description

Plugging and abandonment is the sealing of a well and the subsequent removal of surface material and restoration of the production site to its previous condition. The general aim is not to recover everything from the well bore but to assure that the well is sealed and hydrocarbon reservoirs and other fluid-bearing formations (including brine) cannot leak from the well to the surface or migrate between different formations. Abandonment will remove the surface and upper part of the well to avoid subsequent disturbance.

In the U.S. the abandonment procedures for onshore gas wells are defined in Federal and State regulations. State regulations, which cover abandonment procedures for redundant wells, can include financial provision for abandonment as well as technical requirements and observation of the plugging procedure by local inspectors. The requirements in these regulations have evolved to replace a range of historic drilling and plugging techniques and to avoid future environmental issues arising from wells which had been abandoned.

Offshore, in the North East Atlantic and North Sea, the 1998 OSPAR decision 98/3 which mandates a clean seabed approach (with some derogations) and, the 2010 U.S. Interior Department BOEMRE 'Idle Iron' regulations which requires permanent plugging and abandonment of wells and associated facilities if out of use for 5 years apply. However, these instruments are for protection and management of the marine environment and do not apply onshore. There are industry guidelines for the suspension and abandonment of offshore wells.

Ideally, planning and development of the well needs to recognise that the well will have to be abandoned at some stage. Failure to consider abandonment at the design stage will make eventual abandonment more complex (and expensive).

Plugging generally involves determining where barriers are needed within the well bore and around the liners. Typically, cement is used to seal the surface, aquifer and hydrocarbon (production) zones of the well (including ensuring a seal between the outer casing and surrounding ground). Other plug materials are available (expanding cement, resins, silicone rubber, clay gels and soft metal alloy). Tubing and other downhole equipment may need to be removed from the zones of the well where the plug(s) will be installed to avoid potential leak paths and hence failure. Casings will need to be bridged, cleaned and perforated to ensure effective seals (particular across annular spaces and with the geology outside the casing). Casings may need to be penetrated to allow free movement of cement for the seal. Offshore UK requirements are for two concrete plugs enclosing a non-cement packing with the integrity of the plugs verified before removal and sealing of the top of the well (to about 9 metres below the seabed) and restoration of the seabed.

Onshore, multiple plugs may be required to provide isolation from the surface and avoid movement of gas, hydrocarbons and / or water between different levels of the well bore.

4.4.2 Effectiveness

Historic abandonment processes in the U.S. have led to local environmental pollution incidents. These led to State and Federal regulations to set minimum standards for abandonment, primarily to avoid land contamination, pollution and water pollution. GHG leakage rates for historic and modern abandonment processes are not provided in the literature.

Leakage or failure rates for modern plug and abandonment procedures are not known. Data reported for oil and shallow gas wells in 1993 in Western Canada for gas migration indicate that 45% of the surveyed wells had gas migration (Note that this gas migration may include leakage / failure in operating wells and would predate current well design and abandonment processes). Gas wells in Western Canada were reported (Oilfield Review, 2001) to be difficult to seal requiring further treatment before permanent abandonment.

4.4.3 Cost

Costs for onshore plugging and abandonment have not been established. In the U.S. a bond is required in the event that an operator fails to plug and abandon a well. Bonding is required under federal regulations for oil and gas lease operations to ensure that operators comply with various requirements including plugging, abandonment and remediation / clean-up. The minimum bond is \$10,000 (or \$25,000 for state-wide operation or \$150,000 nationally[14]).

State regulations also apply, for example Kentucky requires a bond of between \$500 and \$5,000 (the value paid depends on the depth of the well) with a higher value bond payable if the depth is greater than 1219.2 metres[15] and site conditions warrant a higher bond. The bond is held until all conditions for abandonment are met by the operator. Bonds for multiple wells are available and the value of the multiple-well bond is risk-related as multiple-well bonds for 'qualified' well operators are cheaper. Qualification is dependent on demonstrated compliance with Kentucky regulations and auditable proof of financial ability to plug and abandon wells.

[14] http://www.gao.gov/assets/310/300218.pdf
[15] Converted, 1 foot = 0.3048 metres

4.4.4 Secondary impacts

Measures to plug and abandon wells are currently undertaken primarily to make the operating site safe for further use and to avoid pollution release to water and land.

4.5 Applicability to Europe

The techniques used or mandated elsewhere (mainly North America) for controlling emissions of GHGs from unconventional gas deposits are a mix of technologies and techniques. Some are specific to unconventional gas exploitation but many are techniques which are in use on conventional natural gas extraction and processing facilities.

4.5.1 Exploration and production

The technologies described in the previous sections include measures which have been demonstrated, and which are a regulatory requirement, in certain regions in North America (and will be a regulatory requirement in the U.S. from 2015). Much of the concern regarding GHG emissions relates to well development and in particular completion and re-fracturing processes. Other activities are similar or identical to the development of conventional gas wells.

Application of these practices for well completion and re-fracturing in Europe may however be constrained by a number of factors:

- Geology: will wells in Europe have sufficient gas pressure to allow application of green completion (as opposed to combustion / flaring).
- Processing infrastructure for captured gas on well completion: at least initially any gas which doesn't meet the sales gas specification would need to be processed further. This may be a constraint if the pipeline or processing infrastructure is not in place and suitable connections available for transferring captured gas.
- Availability and experience in equipment / technology to capture the gas released on well completion and re-fracturing activity: this is likely to be an issue in initial stages of development until vendors develop suitable solutions.

4.5.1.1 *Geology*

The U.S. EPA (2012c) documents indicate that unconventional wells cover shale, coal and sand deposits. The U.S. EPA has determined that well pressures below 500 pounds per square inch (psia) reduced emissions completion (about 35 Bar) may not be suitable. The U.S. EPA has reviewed well depths for various basins in the U.S. and these range from 500 - 12,000ft (150m to 3700m). In the U.S. the well pressure constraint appears to be particularly relevant to shallow coalbed methane wells. However, even in these instances, the combustion of such releases during completion will be required by U.S. regulations.

4.5.1.2 *Processing infrastructure*

During initial development of a well or reservoir there may be limited infrastructure. For example no gathering pipelines, no receiving / refining station (to modify sulphur / inerts / moisture contents), condensate removal and gas compression prior to connection to the gas grid. During re-fracturing, such infrastructure should be in place.

The flow back period during well completion and re-fracturing generates flow back fluid which contains a mixture of sand, waste water, hydraulic fracturing liquids and gas (see Section 2.3.1.4) These phases need to be separated and, for green completion, the gas (and condensate) recovered. The gas may not be suitable for despatch to a distribution pipeline (sales quality) but even if completion gas composition is sales quality there is likely to be a need for further processing (for example moisture removal) before it can be introduced to a distribution pipeline[16].

Treatment of the completion gas before entry into national or regional gas transmission pipelines will be dependent on:

[16] Note that there are different gas quality requirements across Europe (although international pipeline trading has helped set some minimum requirements for pipeline quality gas). Nonetheless gas introduced into national and regional gas transmission systems needs to comply with a range of requirements. The requirements on gas quality including limits on hydrogen sulphide, total sulphur, hydrogen content, oxygen content, dewpoint, Wobbe No, CO_2/N_2/Inert contents, calorific value, activity, chloride and non-methane hydrocarbon content.

- Availability of a gas processing / refining station capable of making gas meet the transmission specification;
- Transport to the refining facility, connection via a local gathering pipeline or tanker transfer.

The recovery process for completion gas in the U.S. is not clear and it may be that recovery can be achieved by simply blending with gas from production wells and treating in on-field processing units. If completion gas is close to sales quality and needs fairly minor treatment then this may be achieved by storing the gas for a short period and then mixing (diluting) with production gas locally. Similarly, if the production gas goes to an on-field or near field gathering and refining facility then mixing with production gas may be a viable approach.

There are existing European gas refineries but these may have limited capability (at present) to receive off-specification gas. They may be some distance from the unconventional gas field and would require connection to the unconventional gas fields.

Many European countries do not have gas refineries (gas is transferred at sales quality from other regions). In countries with conventional gas reserves, natural gas refineries are located at or near the gas reserves (or where pipelines to offshore reservoirs make landfall) and similarly LNG terminals are located at locations which are convenient for LNG import.

4.5.1.3 *Availability and experience*

Shale bed gas development and green completion is an established technique in North America but has had little European application. This represents a risk that availability of equipment and other resources may not be immediately available to the industry. However this should be a temporary or short-term issue.

4.5.2 Downstream processing

E&P are not prescribed activities under the Industrial Emissions Directive (IED) (IED Directive 2010/75/EU) or preceding instruments (in particular Directive 2008/1/EC on integrated pollution prevention and control, IPPC). However, gas refining and associated activities are prescribed activities under the IED. The relevant prescribed activities under IED are:

- 1.2 refining of mineral oil and gas.
- 1.1 Combustion of fuels in installations with a total rated thermal input of 50 MW or more.

These activities are common to ‘downstream’ processing and transport of natural gas from both conventional and unconventional sources. Refining of gas from unconventional sources would be subject to IPPC / IED provisions which requires application of best available techniques for refineries (IPPC bureau, 2003) including (with an emphasis on measures which can influence GHG emission):

- Reducing VOC emissions (for example best available techniques includes quantifying sources and using LDAR campaigns);
- Implementation and adherence to an Environmental Management System;
- Application of good practise for maintenance and cleaning;
- Implementation of a monitoring system;
- Improve energy efficiency.

Many of these are management techniques rather than specific technologies.

4.6 Management techniques

Technology provides part of a best available techniques approach to management of methane emissions from unconventional gas exploration and production. However, best available techniques in other areas of industrial activity include management techniques. In natural gas refining, best available techniques include a range of measures which can help an operator avoid and mitigate emissions. These include:

- Environmental Management System: this can provide a focus for monitoring performance, benchmarking, continuous improvement plans, energy management, emissions assessment and reporting to stakeholders. An externally-accredited system provides credibility and assurance that the processes and plans are being applied;

- Application of good practise for maintenance and cleaning;
- Development of environmental awareness;
- Implementation of monitoring systems, perhaps with a specific focus on LDAR for GHG's;
- Reducing VOC (and methane emissions): identify and quantify sources, LDAR campaigns.

Other management areas relevant to GHG emissions from unconventional gas include:

- Consider transport distances, access roadway provision and compression / processing emission options for siting of well pads;
- Availability of gas for drilling technology;
- Avoiding constraints on deploying on flare or capture technology for well-completion;
- Transport of recovered gas from completion activities to processing facilities.

5 Hypothetical estimation of the lifecycle greenhouse gas (GHG) emissions from possible future shale gas exploitation in Europe

5.1 Introduction

In this chapter we estimate the lifecycle GHG emissions of electricity production from shale gas, taking into account the direct and indirect GHG gas emissions associated with gas extraction, transportation and use, including pre-production and production phases (excluding the exploration stage). Direct emissions are those that occur during operations, e.g. from venting of gas, or from the combustion of fuels used to provide power or transport; indirect emissions are those associated with production of materials used in construction and operation of the wells. This exercise is largely hypothetical, considering the need for further data and the uncertainties regarding EU shale gas development in comparison with North America.

The emissions from shale gas are then compared to lifecycle GHG emissions of electricity production from conventionally extracted natural gas, from liquefied natural gas and from coal. In all of the LCAs, we have only considered emissions arising from normal operations, as it is standard practice in an LCA to exclude emissions related to accidents and spills etc. (JRC-IES, 2010). For gas production, the main source of potential emissions from accidents is fugitive emissions from blowouts, the uncontrolled release of gas from a well when pressure control systems fail. Emissions from potential blowouts are excluded from both the shale gas and conventional gas LCAs.

5.2 Modelling the shale gas life cycle

In developing the LCA for shale gas we have modelled a hypothetical shale gas site located in Europe, as not enough data was available for a particular site to produce a site-specific LCA. We have therefore made use of mainly U.S. based data, drawn from a number of background studies (e.g. NYSDEC, 2011) and also information used in the LCAs reviewed in Section 3. Where ever possible we have compared this with information on likely practices in Europe (e.g. based on information provided in planning applications by Cuadrilla for their UK developments).

It is important to note that the analysis is hypothetical, and represents an illustration of the potential scale and significance of emissions from shale gas exploitation in Europe, based upon experiences from the U.S. In practice the actual emissions from shale gas operations in Europe will be influenced by site-specific characteristics, and by the management practices and technologies employed. In the hypothetical analysis the relative influence of these factors has been explored as part of the sensitivity analysis, wherever data is available to do so.

The lifecycle GHG emissions factors for materials, fuels, transport, and water supply have all been taken from the EcoInvent database and other lifecycle studies.

As in other studies, we have assumed that after well completion, emissions associated with processing and transmission of the gas will not differ significantly from conventional gas processing and transmission. We have therefore adopted common assumptions for these stages for both shale gas and natural gas from conventional sources. This is based upon data for operations relevant for Europe. It is important to note that as with the pre-production stage there will also be uncertainties in the emissions associated with these other stages in the lifecycle. These have been explored in less detail within this current report as we have focussed on what is specific to shale gas.

As with gas from conventional sources, shale gas comprises a mix of methane, other heavier hydrocarbons such as ethane, propane and butane, and CO_2. The literature offers differing opinions as to whether there are any systematic differences between the composition of shale gas and conventional gas. For example, Wood et al (2011) note that there is conflicting commentary on this issue. They cite INGAA[17] (2008), who note that natural gas production from the Barnett fields tends mainly to be 'wet' (i.e. has a high ratio of heavier components to methane) and a low CO_2 content, although this varies significantly across the field. On the other hand, ALL Consulting (2008) suggest that shale gas is typically dry gas composed primarily of methane (90% or more methane), and that while there are some shale gas formations that do produce gas and water, they are the exception based on data from those plays with active development. Stephenson et al (2011) concluded, based on data from the 2011 U.S. EPA Inventory report, that there was no systematic variation in the CO_2 content of conventional and unconventional gas production, and therefore used a single gas composition (typical of average U.S. gas composition) to model both conventional and unconventional production. Jiang et al (2011) give no information on what assumptions were made about gas composition. No data was available in the literature on the composition of shale gas in Europe, and whether this is likely to differ significantly from conventional gas composition. We have therefore adopted the approach of Stephenson et al (2011), and assumed a typical conventional gas composition for shale gas. As the UK is one of the key potential areas for shale gas production in the EU, as well as being a significant producer of natural gas, we have taken the gas composition for UK natural gas, as assumed in the LCA for conventional gas, as the composition of the shale gas in the LCA.

It is clear from the previous LCAs that the main factors affecting estimates of life cycle GHG emissions are:

- Overall lifetime shale gas production of the well;
- Methane emissions during well completion which are dependent on the quantity of methane in the flow back liquid and the treatment of this methane (e.g. venting, flaring or green completion);
- Number of re-fracturing events and the associated increase in productivity that result from these.

We have therefore conducted sensitivity analyses on each of these aspects. We have also considered how the location of the site could affect the distances that materials, water and waste water must be transported to and from the site and have examined the impact that this may have on overall emissions.

We have considered emissions of the three main GHGs, CO_2, CH_4 and N_2O and for our main analysis have applied 2007 IPCC Fourth Assessment Report GWPs of 25 for CH_4 and 289 for N_2O. As a further sensitivity we have also examined the impact of using the GWPs from the Second Assessment Report (21 for CH_4 and 310 for N_2O) as currently used in national inventories for reporting under the Kyoto Protocol, and of using of the higher GWP for CH_4 (of 33) utilised in the LCA by Howarth et al (2011).

5.2.1 Modelling conventional gas and coal life cycle GHG emissions

In order to have a comparison with electricity generation from conventional natural gas and coal, life cycle GHG data for gas and coal from countries which are a key source of imports into the EU have been produced. The EU currently produces 20% of the total volume of natural gas consumed by the 27 Member States. The two main EU producers are currently the Netherlands and the UK, who also possess by far the largest proven, 'discovered potential' and 'undiscovered potential' reserves in the EU27. The other 80% is imported, 85% of which stems from Russia, Norway, Algeria and liquid natural gas (LNG) producers in the Middle East.

As a basis for comparison with the shale gas supplies, the conventional natural gas sources which were modelled are the UK, Norway, Netherlands, Russia and Algeria, plus LNG from the Middle East and Algeria.

For coal based generation, the three main sources of imported coal into the EU which were modelled are Russia, South Africa and South America.

[17] Interstate Natural Gas Association of America

5.2.2 Exploration phase

Emissions from the exploration phase have not been considered in existing LCAs of conventional natural gas. This is because the emissions are considered small in comparison to other stages of the lifecycle, which in turn relates to the large amounts of energy extracted per well. A further reason is the large uncertainty concerning the amount of natural gas to which the environmental impacts related to exploration (see below) and well preparation has to be allocated to.

In the case of shale gas, similar arguments apply about how exploration emissions should be allocated to a well. In some cases, the exploration phase for shale gas may result in a considerable number of wells, and more than might be expected from conventional gas. However, the way these emissions should be allocated to the final shale gas that is delivered is a matter of debate. However, a more important difference between shale and conventional gas is that the productivity of the well is typically much lower than conventional gas wells, meaning that during the exploration phase (which also involves hydraulic fracturing and pilot production testing) emissions will be higher per unit of energy delivered.

The exploration phase is not considered in any of the LCAs of shale gas which were reviewed for this study, and therefore due to a lack of data this phase has not been included in our LCA. Similarly, published LCAs of the conventional gas cycle have not considered the exploration phase, and so it is excluded from the LCA of the conventional gas cycle in this study.

Exploration for conventional gas reservoirs

Although exploration is a core business for gas producing companies it cannot be categorically linked to production. Some exploration will lead to production, some will not. This means that it is hard to include exploration in a life cycle approach that tries to assess environmental impacts associated with a unit of natural gas. An additional complication is that exploration for gas is often tied to exploration for oil. At the exploration stage, there is no knowledge of the yield of either gas or oil and if it so happens that only oil is found, allocation to gas is impossible, although the exploration was targeting gas as well as oil. Therefore it is common practice to exclude exploration from the life cycle inventory and assessment (not only for fossil fuels, but also for mineral ores, see e.g. MSD2001).

5.3 Gas Life Cycle

5.3.1 Preproduction stage –Shale Gas

5.3.1.1 *Site preparation*

The trend in the U.S. is increasingly towards the use of multi-well well pads. This effectively reduces the above surface footprint of the site compared to single-well sites. We have therefore assumed, as in Jiang et al (2011) and based on the NYSDEC report (2011), 6 wells to a well pad. This is consistent with Broderick et al (2011) who state that 6 to 8 wells per pad is typical.

Based on data in NYSDEC (2011), it is assumed that 3 ha of land would need to be cleared for a single multi-well pad. This estimate includes land for access roads, the well pad itself, water and electrical lines, gas gathering lines, and a compression facility (shared with other well pads). This is slightly higher than the value assumed in Jiang et al (2011) of 2.6 ha and Santoro et al (2011) of 2.4 ha. The most detailed breakdown of equipment required to clear and prepare the site is given in Santoro et al (2011) and we have therefore used these assumption: i.e. 6 bulldozers and 1 excavator (with a power of 335 HP and 159 HP respectively) are used to prepare the site, and that these can prepare about a hectare per day.

Land use change emissions due to removal of vegetation are estimated as 167 tCO_2/ha, based on the emission factor for land clearance quoted in Santoro et al (2011) of 167.5 tCO_2/ha. Once again this is potentially a conservative estimate, being significantly higher than the factor implied by Jiang et al (2011) of 12 tCO_2/ha.

5.3.1.2 *Drilling*

Equipment required for drilling is based on the assumptions in Santoro et al (2011) as this provides the most comprehensive list of equipment needed (as compared to other studies where only the prime mover i.e. drilling rig is considered). Based on NYSDEC (2011), it is assumed that drilling a well will take about 4 weeks (about 2 weeks for vertical drilling and 2 weeks for horizontal drilling), and that plant operates 24 hours per day at 50% load. The drills are assumed to be diesel powered, as is the case in most of the U.S. studies.

The length of the well is assumed to be 2678m vertically and 1200m horizontally, which is a representative figure for Marcellus shale gas well from Chesapeake (2009) as quoted in Santoro et al (2011). These characteristics are assumed to provide a reasonable representation of conditions in Europe, based on current evidence. For example, shale gas beds in Poland and the Baltic states are at a depth of more than 2 km although shallow beds do exist (e.g. the Allum shale in Sweden). In the UK, the IEA (2012) suggest the Bowlands shale is relatively shallow, with an average depth of only 1,600m. However, Cuadrilla (2010), on the basis of their planning application, indicate the depth of wells could be up to 3000m.

Other emissions are associated with material used in the drilling phase. This includes water required for the drilling mud, which is assumed to be 455m^3 [18] per well, and 13,000 kg bentonite, which is the main component of drilling mud (based on 20 kg bentonite needed per m^3 of water). These estimates are based on information in Jiang et al (2011). This aspect was not considered in the other LCA studies reviewed in Section 3.

Water for drilling can be sourced from nearby surface water, brought in by pipeline from the utility water supply, or bought in by tanker. Most of the U.S. studies assume water is brought to the site by truck. However, there is evidence that the transportation of water by pipeline is becoming increasingly common (NYSDEC, 2011). The choice of water sources will be site specific as it depends on a number of factors (distance to the water abstraction source or water distribution network, the ease with which approval can be obtained for abstraction and construction of pipelines, and the ease and cost of constructing pipelines). Emissions from water provision are generally highest when the water is tankered in and we have therefore assumed in our base case that all water is tankered in. We have also conducted a sensitivity analysis, where we examine the reduction in emissions if all water was to be delivered by pipeline rather than tanker.

It is assumed that water, bentonite and the drilling equipment itself has to be transported a distance of 100km to the site. We have also examined the sensitivity of the results to this assumption, by also modelling cases where the transport distance is lower (50km) and higher (250km).

5.3.1.3 *Materials consumption*

During well drilling and site preparation, the main materials consumed are steel and cement for the well casing, and gravel and asphalt for preparation of the well pad and access roads etc. The quantities of materials required per well were estimated by Santoro et al (2011) who combined these with estimates of the GHG emissions associated with production of these materials to estimate the total emissions associated with materials consumption. We have used this value, adjusted for the consumption of chemicals used in hydraulic fracturing which we have estimated separately (see below) to provide an estimate of emissions associated with resource consumption; total emissions associated with steel, cement, gravel and asphalt consumption are thus estimated as 1051 t CO_2 per well[19].

5.3.1.4 *Hydraulic fracturing*

For the hydraulic fracturing of a well, the pumping requirements suggested in Santoro et al (2011) are assumed, i.e. that pumps with a total HP of 9300 operate for 70 hours per well at full load to complete a series of 15 hydraulic fracturing events. This running time is based on data from NYDEC (2009) and is for average injection rates and pressure ranges found in Marcellus shale. The updated NYDEC (2011)study reports no change in these typical running times. In addition it is assumed that a 1200 HP generator operates at 50% load for a similar period of time. The estimate of running time may be conservative, as other studies, e.g. Jiang et al (2011), assume that 15 hydraulic fracturing events will only require 30 hours of running time.

Water required for the hydraulic fracturing of one well is assumed to be 18,184 m^3 as used by Jiang et al (2011). This is within the range suggested by NYCDEC (2011) of 9,000 to 29,000 m^3. Stephenson et al (2011) also assume a water requirement of 18,184 m^3, Santoro et al (2011) assume a slighter

[18] 1 Imperial gallon = 0.00454609188 cubic metres
[19] The GHG emissions associated with production of a tonne of each material as cited in Santoro are based on U.S. values. The values cited were compared with values from the EcoInvnet database based on European production; differences ranged from between 15 and 30%.

higher consumption of 22,730 m^3 per well. It is assumed, as for the drilling stage, that this water is supplied by tanker in the base case, although the impact of piping water in is examined in a sensitivity study.

Jiang et al (2011) also provide a breakdown of the typical components of fluid additives, and this is used to make estimates of the GHG emissions associated with production of the four largest components: silica quartz sand (9%), hydrochloric acid (0.11%), petroleum distillate (0.08%) and isopropanol (0.08%), but as noted in Section 2.3.1.3, the composition of fracturing fluid is variable. These are all assumed to be transported 100 km to the site in the base case, with this distance varied for the transport sensitivity analyses as described above.

5.3.1.5 *Well completion*

The emissions arising from well completion are based on the U.S. EPA's Background Supplemental Technical Support Document for Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (2012b). As described in Chapter 3 this document provides a detailed review of emissions from unconventional gas completions, taking into account evidence gathered as part of the consultation on the draft document.

The updated U.S. EPA document provides a range of estimates that could potentially be applied in the emissions analysis:

1) 9,000 thousand cubic feet (Mcf) (254,700 m^3) of gas per completion is given as the default value for unmitigated emissions from unconventional gas completions (i.e. shale, tight and coal bed methane (CBM)).
2) 6,123 Mcf (173,281 m^3) of gas per completion is given as a lower value based on (similar to) 95% confidence interval for unmitigated emissions from unconventional gas completions (i.e. shale, tight and coal bed methane).
3) 11,676 Mcf (330,431 m^3) of gas per completion is given as an upper value based on (similar to) 95% confidence interval for unmitigated emissions from unconventional gas completions (i.e. shale, tight and coal bed methane).
4) 11,025 Mcf (312,006 m^3) of gas per completion is provided as an estimate for just shale/tight gas based on the weighting of data by two formation categories (CBM and tight sands / shale) based on the number of completions in formation categories.

In the LCA an emissions factor of 11,025[20] Mcf (312,008 m^3) of gas per well completion has been applied, since this latter estimate reflects the fact that emissions may vary by formation type (i.e. emissions from shale and tight gas may differ from CBM). It is also similar to the upper value across all formation types. This is an unmitigated value. For our base case we assume that 15% of these emissions are flared (with a combustion efficiency of 98%), with the remaining (85%) vented. We also conducted sensitivity analyses to establish the reduction in emissions resulting from a higher flaring rate (90%) and from green completion, and the increase in emissions if all of the gas is vented.

We also constructed a pessimistic scenario, where well completion emissions are assumed to be higher at 14,000 Mcf (396,200 m^3), and are all assumed to be vented. Since a 95% confidence level for the value of 11,025 Mcf (312,008 m^3) was not calculated in the EPA (2012b) report, we have estimated what might be a realistic upper limit for this estimate by taking the ratio between the central value and upper values stated for all unconventional completions.

5.3.1.6 *Waste treatment*

Waste treatment activities which have been considered are the disposal of drilling mud and of waste water generated from hydraulic fracturing. As discussed earlier in the report, of water used for hydraulic fracturing a proportion flows back. The NYSDEC (2011) reports that in Marcellus wells between 9% and 30% of water used flows back, although other studies quote higher water flow back rates, e.g. Stephenson et al (2011) suggest (based on NETL, 2009) that 30 to 70% of water flows back, and Jiang et al (2011) that 35 to 40% flows back. Of the water that flows back, some can be recycled, and used for hydraulic fracturing of other wells on the site. Re-use involves either straight dilution of the flow back water with fresh water or the introduction on-site of more sophisticated treatment options. These can range from using polymers and flocculants to precipitate out and remove metals to filtration technologies. NYSDEC (2011) notes that there has been an increasing

[20] We note that this value is at the lower end of some of the values quoted in the life cycle assessments reviewed in chapter 3. However, as discussed in this chapter, the recent review by the U.S. EPA takes into account the primary research

trend towards reuse and that operators plan to maximise reuse, although this can be constrained by high levels of contaminants in the flow back water, or a lack of other wells close enough for the water to be reused.

Jiang et al (2011) suggests that 30% to 60% of water which has flowed back can be reused; suggesting that overall (for a central estimate of 45% reuse) about 17% of the water used for hydraulic fracturing ends up as waste water which must be treated. Stephenson et al (2011) makes a more pessimistic assumption that 50% of the water used for hydraulic fracturing ends up as waste water which must be treated. We have adopted this latter, more conservative assumption in our analysis.

Flow back water can be disposed of in several ways, by tankering the water off site to dispose of by deep well injection, disposal in municipal sewage treatment works, or in a specialised industrial waste water treatment plant. An alternative practice in the U.S. is to store the waste water in open pits; this option has also been utilised at the Lebien LE-SH well in Poland. Such water would still require treatment before it could be disposed of. However, NYSDEC (2012) reports that operators proposing to drill in New York State would not routinely propose to store flow back water either in reserve pits on the well pad or in centralized impoundments.

Previous studies have assumed either disposal in municipal waste water treatment facilities (Broderick et al, 2011) or in specialised waste water treatment facilities (utilising reverse osmosis and evaporation or freeze – thaw evaporation) (Stephenson et al, 2011), or deep well injection (Jiang et al, 2011). NYSDEC (2011) highlights that some contaminants which are likely to be present in flow back water may not be properly treated in a standard sewage treatment facility, and that treatment in a municipal sewage treatment plant can affect the plant due to the salt content of the water, which if not properly handled, can reduce the overall effectiveness of the sewage works. We therefore do not consider that disposal to standard sewage treatment facilities is likely to be a viable option for disposal of flow back water. Instead we assume that more advanced treatment e.g. involving reverse osmosis (RO) is required, and base emissions associated with this on an electricity consumption for RO of 4 kWh/m^3 (Vince et al, 2007). It is assumed that the waste water is transported 100km to such a facility, with the sensitivity to this assumption analysed in the transport sensitivity analysis.

Injection to deep well for disposal of waste water is not discussed in the literature for extraction of shale gas in Europe, and is therefore not considered. Storage in open pits would still require treatment of the water (potentially on site) before it can be discharged to surface waters, but could remove the need to tanker the water off site. Our assumptions for waste water treatment can therefore be considered to be conservative.

Drilling mud is assumed to be transported 100km for disposal in a landfill.

5.3.1.7 *Productivity of well*

The overall productivity of the well is assumed to be 2 Bcf (56.6 million m^3) based on Stephenson et al (2011). This is based upon a survey of production data published for unconventional gas fields in the U.S. which gave an average productivity of 3.8 Bcf (107.54 million m^3), and data from the U.S. Geological Survey which showed that the range for horizontal wells was 0.9 to 2.6 Bcf (25.47 million m^3 – 73.58 million m^3) per well. Our assumed productivity is lower than that assumed in Jiang et al (2011), of 2.7 Bcf (76.41 million m^3). Broderick et al (2011) quote a lower range of 0.2 to 1.8 Bcf (5.66 million m^3 – 50.94 million m^3) although this is based on 2006 data. We have also carried out a sensitivity analysis assuming that productivity in the wells is lower (1 Bcf / 28.3 million m^3) and higher (3 Bcf / 84.9 million m^3); in both these sensitivity studies we have made the simplifying assumption that the well completion emissions are independent of the lifetime productivity of the well

A further consideration is the influence of re-fracturing on the overall productivity, and the associated emissions. ICF[21] (2009) suggest that re-fracturing can frequently restore the well's production rate close to between 75% and 100% of the initial rate, although the post-fracture production rate would be expected to be lower with each subsequent re-fracturing treatment. The same report suggests that re-fracturing the well can increase the cumulative amount of gas recovered by 80% to 100%, but it is not clear how many re-fractures of a given well are required in order to deliver this return. Likewise, it is not clear how frequent such events are. Due to the levels of these uncertainties we have not carried

[21] Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs. ICF International (2009).

out further detailed analysis for this report. We note that in the U.S. the drilling of new wells is often preferred over re-fracturing of existing wells.

Other evidence from the U.S suggests that re-fracturing is less common, with a much greater proportion of well completions associated with new wells, than from the re-fracturing of existing wells.

In the analysis by Broderick et al (2011) it was assumed that outputs from re-fractured wells were 25% higher than un-fractured wells. We have used this assumption in our sensitivity analysis i.e. that re-fracturing the well once will increase the cumulative output of gas from the well over its lifetime by 25%.Our base case assumes that there is no re-fracturing of the well.

5.3.2 Preproduction stage – Conventional gas

As discussed earlier, emissions from the preproduction stage for natural gas (of both exploration and drilling) have not typically been considered in existing LCAs of natural gas, and the exploration phase has been excluded from our LCA of both shale gas and conventional gas. In order to ensure that the boundaries of the LCA for conventional and shale gas are equivalent, it is however necessary to estimate the emissions associated with well preparation i.e. drilling for conventional gas as this stage is included in the shale gas life cycle.

Our estimate is taken from Stephenson et al (2011) which estimates the emissions associated with diesel use for well drilling are 0.3 g CO_2eq/MJ, assuming 15 days of 12 hour operation of 4500 HP engines, and a productivity of the well of 2 bcf (56.6 million m^3). In addition, we have used an estimate from Stephenson et al (2011) of 0.35 g CO_2eq/MJ for methane emissions on well completion; this is based on an estimate from the API compendium of 25.9 t CH4 per completion day, assuming that 2 days are required to complete the well and that 51% of the methane emissions are flared. The proportion of well completion emissions flared is based on data from the EPA. Values from Stephenson et al (2011) are used as this is the only LCA study reviewed which included estimates for this stage for conventional gas.

5.3.3 Production stage

5.3.3.1 *Pipeline gas production*

Extraction of non-associated natural gas gives a mixture of raw gas, condensed higher hydrocarbons, free water and entrained particles. The raw gas is isolated from solids and fluids by flashing (also known as primary separation), and must then be further processed to separate the methane fraction from co-products or pollutants such as:

- Water vapour;
- Acid gases (CO_2, sulphurous compounds);
- Nitrogen (N_2);
- Condensable hydrocarbons (C_5+).

Ethane, propane and butane may also be separated out where there is a use for them, e.g. a petrochemical industry which can utilize them as a feedstock in steam cracking. Which processes are applied to treat the gas depends on the quality of the raw gas as well as the required standard for the processed gas. In the Netherlands, for instance, a high percentage of N_2 is still present after processing.

Most treatment processes require electricity for valves, pumps, etc. The electricity is often produced on site in the case of off-shore production and treatment or fields located in remote areas. For on-shore production in less remote areas electricity may be taken from the grid. Other inputs to the treatment process include methanol, which may be added before dehydration, but is mostly recovered and recycled, and activated carbon and glycol, involved in the desulphurization and dehydration steps.

Based on publicly available data, it is assumed that the percentages of gas throughput shown in Table 12 are used to supply energy to treat the gas, or are vented or flared. This equates to the values shown in Table 13, for emissions per GJ of gas delivered to the power station.

For Norwegian, Dutch, UK and Algerian pipeline gas, gas turbine consumption is associated with subsea pipeline transport from either off shore gas fields (Norway, UK, Netherlands) or from one side to the other of a sea (Algeria). Further discussion on the potential variation in the estimates is provided in Section 5.3.4.1.

The applied data concerns country or operator averages and has been derived from EcoInvent (2007), ExternE reports and from company reports for operators in the Netherlands. EcoInvent data is in turn based on reports from operators and permitting authorities.

For environmental impacts related to natural gas production in the EU and Norway data from Ecoinvent was taken. This data is somewhat older and does not necessarily reflect the current status of technology and emissions.

The data has been allocated to natural gas production, which means that the total impact related to natural gas production or, in the case of the majority of Norwegian gas production, production of oil and associated gas has been divided over oil, gas, condensate and other products.

In practice energy consumption related emissions and fugitive emissions will differ from well to well or treatment plant to treatment plant, depending on:

- Level of depletion of the gas reservoir and associated requirements for depletion compression;
- Composition of raw gas and processing required to clean the gas up to pipeline specifications;
- Equipment applied and level of energy integration realized.

This also explains the variations in alternative estimates. For example, in EcoInvent (2007) specific energy consumption for gas treatment in Siberia is indicated to be 1% of produced and transmitted gas, while in the Austrian ExternE report a specific energy consumption of 0.65% of transmitted gas is indicated.

Given the focus of the study and the size of the emissions it is beyond the scope of this study to conduct an in-depth analysis of the variations in GHG emissions for gas treatment. However, for illustration, the ranges demonstrated by the results for different regions in the table below, provides an indication of the relative uncertainty in these estimates.

For the shale gas base case, we have assumed that gas use for treatment and fugitive emissions are at the same level as for UK conventional gas. We have also conducted a sensitivity analysis where we have assumed the higher levels of gas use for treatment associated with Norwegian conventional gas.

Table 12: Gas use for treatment and fugitive emissions (% of gas throughput)

	Netherlands	*UK*	*Russia*	*Algeria*	*Norway*
Used to supply energy	1.17%	1.00%	0.64%	1.00%	1.30%
Of which:					
gas turbine	0.77%		0.25%	0.64%	0.94%
drying	0.40%		0.39%	0.36%	0.36%
Diffuse emissions / vented	0.04%	0.18%	0.44%	0.13%	
Flared	0.12%	0.25%		0.25%	0.30%

Source: Calculated by CE Delft based on EcoInvent (2007), ExternE reports and for the Netherlands, operator reports.

Table 13: Emissions from gas treatment (kg/GJ gas delivered)

	Netherlands		**UK**		**Russia**		**Algeria**		**Norway**	
	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4
Used to supply energy	0.65		0.56		0.40		0.63		0.73	
Of which:										
gas turbine	0.42		0.56		0.16		0.40		0.52	
drying	0.22				0.24		0.23		0.20	
Diffuse emissions / vented		0.01		0.03		0.10	0.00	0.02		
Flared	0.07		0.14				0.16		0.17	

Source: Calculated by CE Delft based on EcoInvent, ExternE reports and for the Netherlands, operator reports

5.3.3.2 *LNG production*

Liquid natural gas (LNG) is natural gas cooled to a low temperature (-162^{o}C) so it becomes a liquid occupying a much smaller volume. It can then be transported over long distances without the need for fixed infrastructure. The LNG process consists of several steps: processing; liquefaction; transport; storage and regasification.

The processing step for LNG is essentially the same as described above. The undesirable components (H_2O, CO_2, etc.) are removed, and then the higher hydrocarbon fractions are removed during the liquefaction process. Cooling down to condensation temperature is done in industrial installations, typically with a number of cooling stages, which can produce up to 5 Mton per year of LNG. LNG often consists of both methane and ethane; liquefied ethane is re-added to fluid methane after methane liquefaction (as ethane liquefies before methane does). The by-products of LNG production are liquefied petroleum gas (LPG) and gasoline, the heavier fractions of the raw natural gas.

The LNG is stored in a full containment tank normally consisting of a concrete outer tank and an inner tank of 9% nickel steel. The boil-off gas and pre-cooling and loading vapours are compressed and used as fuel gas for the liquefaction units or flared. Transportation to and from storage is driven by pumps. Storage may also take place at other stages in the LNG chain (after international transport or before regasification). Again, boil-off gas is mostly put to use, but may be vented in emergencies.

Table 14 shows the percentage of gas used for processing LNG and fugitive emissions; and Table 15 shows these emissions on a kg per GJ basis. Further discussion on the potential variation in the estimates is provided in Section 5.3.3.2. Data for GHG emissions related to LNG production has been adapted from Sevenster and Croezen, (2005) which was based on publicly available data from operators (Middle Eastern LNG) and on EcoInvent. In practice GHG emissions and energy consumption will depend on raw gas composition, but also on the applied design and the age of the installation. There are five suppliers of technology for large scale LNG trains, each utilizing their own type of refrigerator and refrigeration cycle design. Train capacity and associated requirements for compression capacity will influence the applied size of gas turbines and their efficiency, the larger the gas turbine the higher the efficiency (in general).

Table 14: Gas use for treatment and fugitive emissions – LNG (% of gas throughput)

	Algeria	Middle East
Used to supply energy	17.7%	9.7%
Of which:		
gas turbine	17.3%	9.4%
drying	0.4%	0.3%
Diffuse emissions / vented	0.1%	0.1%
Flared		0.2%

Source: Calculated by CE Delft based on EcoInvent, ExternE reports

Table 15: Emissions from LNG gas processing (kg/GJ)

	Algeria		Middle East	
	CO_2	CH_4	CO_2	CH_4
Used to supply energy	9.87		5.79	
Of which:				
gas turbine	9.67		5.58	
drying	0.20		0.21	
Diffuse emissions / vented		0.01		0.01
Flared			0.12	

Source: Calculated by CE Delft based on EcoInvent, ExternE reports

Table 16: Examples of LNG installation specific energy consumptions and fugitive emissions

	Bonny Island train 4/5	Peru LNG	Oman LNG	Nigeria LNG	Rasgas	Qatargas	Snovhit
Gas consumption (as fraction of raw gas)							
- refrigeration cycle	6.2%	6.9%					
- auxiliary electricity	1.6%	1.4%					
- hot oil system	N/A	0.3%					
- flaring	N/A	-	0.2%	0.4%	0.3%	0.4%	
Total	7.9%	8.7%	9.9%	11.5%	12.5%	12.9%	6.0%

Source: Calculated by CE Delft

5.3.4 Transmission stage

5.3.4.1 *Pipeline transmission*

After processing, gas is often transported over large distances, mostly through a pipeline system consisting of the pipeline, compression stations, import / export stations and metering. Gas is compressed to pressures of approximately 70 bar before transport, and intermediate compressor stations along the pipeline compensate for the pressure loss that arises from the friction between the gas and pipeline wall. Compressors are almost always driven by natural gas, as this is obviously easily available. In the case of undersea pipelines, the initial pressure may be higher (more than 200 bar) since intermediate compression is not possible.

Upon 'arrival' at the receiving end, blending stations, metering and pressure-regulation stations as well as export / import stations take care of the connection between the long-distance transmission grid and the regional distribution grid. Quality control, pressure (and temperature) control and odorisation take place at these points.

Apart from energy consumption for the transport itself, maintenance and check-up activities, especially in remote areas, may require energy. Another source of gas 'consumption' during transport is leakage of the gas from the pipeline.

The estimated consumption of gas for compression, and also the estimated leakage of gas from pipeline transmissions systems, is shown as a percentage of gas throughput in Table 17 and in terms of kg per GJ of gas delivered in Table 18. Emissions are based on transport from the gas field to the Netherlands (as a representative European location).

For shale gas, we have assumed in the base case that gas is transported 500 km (giving an energy use of 0.9% of gas through-put and diffuse emissions of 0.013% of gas throughput). We have also conducted a sensitivity analysis where it is assumed the gas is transported a distance of 1,000 km.

Table 17: Emissions from Pipeline transmission (% of gas throughput)

	Netherlands	UK	Russia	Algeria	Norway
Used to supply energy	0.18%	0.45%	11.60%	7.02%	1.62%
Diffuse emissions	0.003%	0.01%	0.68%	0.10%	0.02%

Table 18: Emissions from Pipeline transmission (kg/GJ)

	Netherlands		UK		Russia		Algeria		Norway	
	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4
Used to supply energy	0.099		0.251		6.476		3.984		0.918	
Diffuse emissions		0.001		0.001		0.136		0.016		0.004

Estimates of the GHG emissions related to pipeline transportation in Russia have been taken from a 2005 study which made an inventory of GHG emissions within the Russian transmission system. Gazprom is however actively mitigating environmental impacts and current emission rates may be less than those included in the table above. Data for pipeline transportation within the EU were taken from the Marcogaz inventory and reflect country averaged data provided by the national transmission grid operators.

In general, energy consumption will depend on demand on the pipeline and the velocity of the gas, and will change between seasons. For example, in the Netherlands during the summer, demand is at such a low level that gas injected in the transmission system can be transported to the customer without any intermediate compression, while in winter intermediate compression stations operate at near full capacity (Sevenster and Croezen, 2005) Apart from the level of demand, the other main influence on emissions is the efficiency of the technologies used e.g. the driver for the transmission compressor, and also the level of mitigation measures taken to reduce fugitive emissions.

5.3.4.2 *LNG transport*

Long distance transport of LNG takes place primarily by cargo ships with an insulation system to keep the temperature at -162ºC. Boil-off gas provides a large fraction of the fuel needs for the ship, also on the return journey when some LNG is left in the tanks to ensure that the gas concentration in the tanks is above the upper explosion limit (UEL).

At the arrival port LNG is stored, pressurised with a pump, regasified and injected into the gas grid. Regasification consists of increasing the LNG temperature using (sea) water at roughly ambient temperature as a heat transfer medium. After quality control, the gas is then ready to be transported in the regular distribution network.

The main processes leading to GHG emissions in this part of the life cycle are combustion emissions from shipping, power consumption for pumping and re-liquefaction and combustion emissions related to regasification.

During the voyage part of the LNG evaporates (boils off). The boil-off ratio (BOR) depends on the ambient temperature, size and age of the ship, its speed and the level of insulation, and is minimized by cell isolation. Typical values for existing tankers are about 0.2% of the full contents per day with new designs having a guaranteed maximum BOR of 0.13%/day - 0.15%/day; BORs of < 0.1%day have been reported, but there are also data suggesting a boil off ratio of approximately 0.3%/day in practice[22]. Until recently, LNG carriers have been equipped with steam turbines powered by heavy fuel oil (HFO) and / or LNG boil off gas. The thermal efficiency of the boiler and steam turbine configuration in these vessels is approximately 30%. An alternative and new development is the application of diesel / LNG dual fuel engines. At present approximately 15 vessels with this new propulsion system are on order. The engines can run on MDO (medium diesel fuel), HFO or boiled off LNG. A second new development is the re-introduction of a boil-off gas reliquefaction facility on-board the LNG carriers. In the current analysis we taken into account the first development, but not the second.

The energy consumption and GHG emissions from LNG are determined by the:

- Travelling distance;
- Vessel size;
- Whether boil off is utilized as a fuel or not;
- The applied power generator for propulsion (boiler, engine, electric).

There are no fugitive emissions since all vapour is collected to be used as a fuel.

In the table below a comparison is made of the energy consumption and associated emissions per 1,000km transport distance (with data from various sources).

Table 19: Comparison of emissions estimates from LNG transport from alternative sources.

	Yoon & Yamada (Japan)	EcoInvent	MAN B&W + own calculation	
Some study specific details			Average	Best available technology
Trip distance, one way (km)	5,540		12,038	12,038
Cargo load (ton)	52,977		70,500	70,500
One way or return trip considered?	Not known		return	return
BOR				
- loaded voyage	0.32%	0.15%	0.12%	0.12%

[22] According to *Yoon* an average tanker sailing from Brunei, Australia or the Middle East with a delivered cargo of 53,000 ton over a distance of 5,540 km (one way trip) consumes 1,150 tonnes of LNG as fuel. Assuming an average speed of 19 knots/hour – requiring a 7 day trip – the boil off ratio is $\frac{1.150}{7 \times (1.150 + 53.000)} = \pm 0,3\%$

- ballast voyage			0.06%	0.06%
Specific fuel consumption (kJ/ton·km)	269	330	307	205
Consumptions				
- natural gas (Nm^3/1,000 km·Nm^3)				
a. energy source	0.39%	Not specified	0.21%	0.21%
b. fugitive				
c. flaring				
- other fuels/energy carriers (kJ/1,000 km·Nm^3)				
a. electricity				
b. Heavy / medium fuel oil	59.3	Not specified	205.0	103.0

The consumption data taken from Yoon & Yamada (2005) is based on information for 44 ships shuttling between Japan and four of the major LNG production locations supplying Japan: Indonesia, Brunei, Australia and the Middle East. These figures may be considered reliable. The figures concern approximately 40% of LNG transported. Emissions include the contributions of fuel oil utilization. In EcoInvent the total fuel requirement of the LNG tanker is assumed to be covered by boil off. However, this is not the case in most practical situations, as shown in the other studies.

The figures given in the columns with the title '*MAN B&W + own calculation*' mainly refer to a paper from MAN B & W (MAN, 2005) in which an economic comparison is made between a conventional LNG tanker with steam turbine propulsion and an LNG tanker with a dual fuel engine. The analysis is made for a new design (see low BOR and large volume) and is made applying rules of thumb.

The emissions given in the columns with the title '*MAN B&W + own calculation*' concern results of own calculations. These are based on the assumed composition of LNG, heavy fuel oil and medium fuel oil. The presented figures do not refer to a practical situation and can be qualified as estimates. The specific fuel consumption however does correspond well with the practical data given in (*Yoon & Yamada, 2005)*. The similarity demonstrates that a good estimation can be made on the basis of rules of thumb.

Total estimated GHG emissions from LNG transport are shown in Table 20 as a percentage of gas throughput and in Table 21 as kg of gas emitted per GJ of gas consumed. The transport related emissions assume shipping to the Netherlands and then 100km transport by pipeline.

Emissions have been calculated assuming the specific average energy consumptions of 102 kJ/tonne·km of boil off gas and 205 kJ/tonne·km of heavy fuel oil (MAN B&W average). Distances to the North West EU amount to 5,000 km for Algerian LNG and 20.000 for Middle Eastern LNG.

Table 20: Emissions from LNG transport (% of gas throughput)

	Algeria	Middle East
For energy (shipping)	1.03%	4.14%
For energy (regasification and pipeline)	0.55%	0.55%
Diffuse emissions (pipeline)	0.003%	0.003%

Table 21: Emissions from LNG transport (kg/GJ)

	Algeria		Middle East	
	CO_2	CH_4	CO_2	CH_4
For energy	0.893		2.671	
Diffuse emissions		0.0004		0.0004

5.3.5 Power generation

Power generation is assumed to be in a combined cycle gas turbine (CCGT) power station. During combustion the hydrocarbons making up the natural gas are completely burned and converted into CO_2. Nowadays, gas turbine operational parameters allow for an overall efficiency of 60% - 61% as demonstrated at Baglan in Wales and Irsching, Bavaria. Future power efficiency is expected to increase to 65%

However, for the purposes of the current analysis an overall efficiency of 52.5%[23] has been applied in all the scenarios. We have though also examined what the impact of a more efficient generation plant will have on the total emissions.

5.3.6 Results

The overall results from the lifecycle assessment are presented below. The results are presented firstly for the shale gas cycle and then for the conventional gas cycle. In both cases there are a range of estimates provided to reflect differences in the assumptions.

The results are presented for kWh of electricity delivered to the electricity grid from a power station, based on the assumed plant efficiency described above.

5.3.6.1 *Shale gas*

Across a range of scenarios, the emissions from the use of shale gas to produce electricity are estimated to be in the range of 409gCO_2eq to 472gCO_2eq per kWh of electricity generated. As for conventional sources of gas, emissions are dominated by the combustion at the electricity generation plant, which typically represents around 90% of the total emissions impact.

A range of scenarios have been explored. There is no preferred scenario, although a base case has been developed for the purposes of comparison. The base case is based on the assumptions described earlier and primarily assumes characteristics on the performance and management of shale gas exploitation which is in-line with current practice in the U.S. Exceptions are transport distances, which are lower reflecting the fact that exploitation sites in Europe are likely to be less remote from utilities such as water supply, waste water treatment and sources of materials required for site preparation than many U.S. sites. Whilst it is not necessarily the case that this represents a base case for practices in Europe, it provides a reasonable basis for comparison. A series of scenarios are then explored which examine circumstances that deviate from the base case assumptions including the management of emissions arising from flow back, the productivity of the well and assumptions around transport impacts.

The scenarios can be defined as follows.

- Base Case: this scenario assumes 15% of the emissions from well completion are flared and the remainder are vented. It assumes a well productivity of 2 bcf (56.6 million m^3), and a transport distance of 100km.

The following scenarios take the characteristics of the base case and then test the sensitivity of one of the variables:

- High Productivity: the productivity of the well is 50% greater than in the base case.
- Low Productivity: the productivity of the well is 50% lower than in the base case.

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[23] As defined in Commission Decision of 21 December 2006 establishing harmonised efficiency reference values for separate production of electricity and heat in application of Directive 2004/8/EC of the European Parliament and of the Council (2007/74/EC)

- Re-fracturing: in addition to the initial hydraulic fracturing stage, the well is re-fractured one further time. It is assumed that this additional hydraulic fracture will increase the volume of recovered gas by 25%.
- Flaring: 100% of emissions from well completion are flared.
- Green Completion: 90% of emissions from well completion are captured and utilised and the remainder (10%) are vented.
- Venting: 100% of emissions from well completion are vented.
- Low transport: transport distances are at the lower end of range identified (50km).
- High transport: transport distances are at the high end of range identified (250km).
- Higher emissions from flow back: unmitigated well completion emissions are 14,000 Mcf (396,200 m^3), and are all assumed to be vented.
- Piped water: it is assumed that all fresh water required is piped rather than tankered in.
- Higher emissions from gas treatment and transmissions: transmissions distance for shale gas is increased from 500 to 1000 km and energy use for gas treatment is higher.
- 'Worst' case scenario: this most pessimistic scenario combines all of the assumptions which give higher emissions i.e. low productivity, higher emissions from flow back gases, all of which are vented, higher transport distances and higher gas transmissions distances.

Details of how the parameters were varied are given in Table 22.

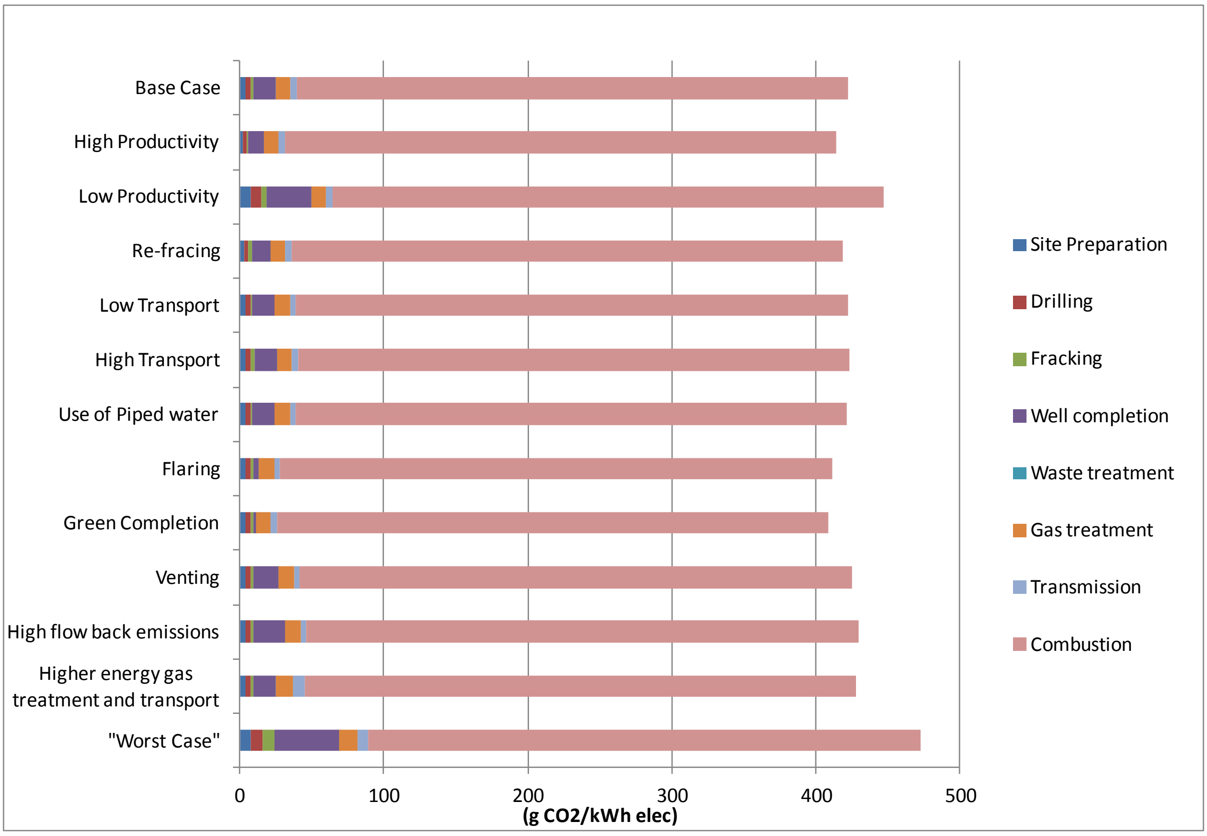
Table 22: Parameters varied in each scenario

	Well Product-ivity over lifetime (bcf)	*Well Product-ivity over lifetime(million m^3)*	*No. of hydraulic fracturing cycles*	*Well completion emissions flared*	*Well completion emissions vented*	*Transport distance* (km)*
Base Case	2	56.6	1	15%	85%	100
High Productivity	3	84.9	1	15%	85%	100
Low Productivity	1	28.3	1	15%	85%	100
Re-fracturing	2.5	70.75	2	15%	85%	100
High transport	2	56.6	1	15%	85%	250
Low transport	2	56.6	1	15%	85%	50
Use of Piped water	2	56.6	1	15%	85%	100
Flaring	2	56.6	1	90%	10%	100
Green Completion	2	56.6	1	0%	10%	100
Venting	2	56.6	1	0%	100%	100
High flow back emissions	2	56.6	1	0%	100%	100
Higher Energy gas treatment and transport	2	56.6	1	15%	85%	100
"Worst Case"	1	28.3	1	0%	100%	500

* For materials and wastes

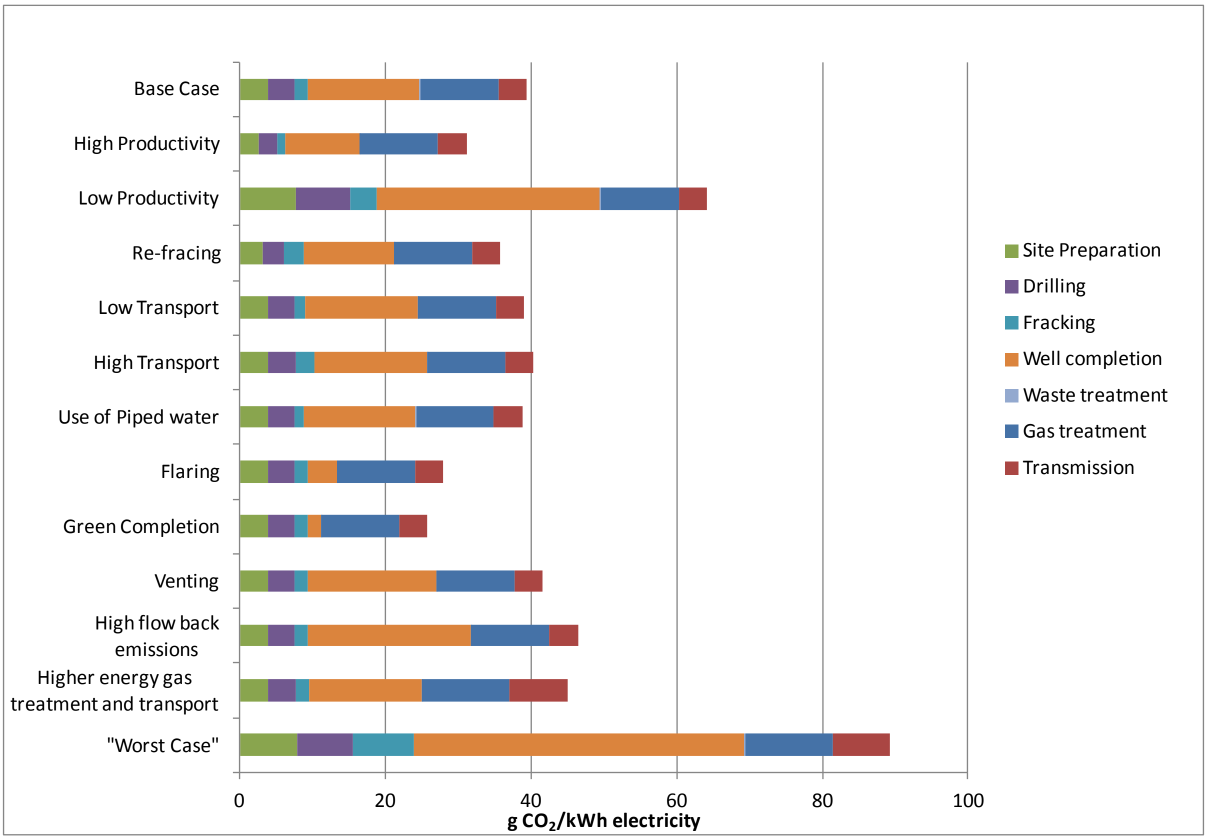
The results of the sensitivity analysis are shown in Figure 7 below. These results are expressed as gCO_2/kWh of electricity delivered to the grid.

Figure 7: Lifecycle GHG emission from electricity production using shale gas (gCO_2/kWh)



As described previously, the main difference between the shale gas fuel cycle and conventional gas is associated with the pre-production stage. It is therefore useful to explore the variability of the emissions when the combustion stage is excluded. These results are shown in Figure 8.

Figure 8: Lifecycle GHG emissions from electricity using shale gas – pre combustion stages only (gCO_2/kWh)



The influence of the key assumptions on the overall emissions can be more clearly seen. As you would expect, the productivity of the well has an important influence on the overall emissions[24], as does the assumed management of emissions from well completion. The impact of assumptions on transport distance has little impact on overall emissions. Changes from the base case for each scenario are shown in Table 23.

Table 23: Lifecycle emissions for electricity generation from shale gas (g CO_2/kWh electricity)

		Change from base case	
	g CO_2/kWh	g CO_2/kWh	%
Base Case	422.4		
High Productivity	414.2	-8.3	-2.0%
Low Productivity	447.2	24.8	5.9%
Re-fracking	418.9	-3.6	-0.8%
Low Transport	422.1	-0.3	-0.1%
High Transport	423.4	0.9	0.2%

[24] This assumes that emissions from well completion are unrelated to the overall levels of productivity.

Use of Piped water	421.9	-0.6	-0.1%
Flaring	411.1	-11.4	-2.7%
Green Completion	408.8	-13.6	-3.2%
Venting	424.7	2.3	0.5%
High flow back emissions	429.5	7.0	1.7%
Higher energy gas treatment and transport	428.0	5.6	1.3%
"Worst Case"	472.3	49.9	11.8%

All of the results from the above scenarios are calculated based on using 100 year GWPs for CH_4 and N_2O of 25 and 289 respectively as set out in the IPCCs most recent (fourth) Assessment Report. However GHG reporting in national inventories and under the Kyoto protocol uses 100 year GWPs of 21 for CH_4 and 310 for N_2O (as set out in the IPCC's Second Assessment Report. We have therefore carried out a sensitivity study to see the impact on lifecycle emissions of using these GWPs to calculate the CO_2eq emissions. Similarly we have looked at the impact of using the higher GWP of 33 for CH_4 as used by Howarth et al (2011). Table 24 shows the impact of the different GWPs on the base case, and on the scenario with the highest methane emissions – venting. Use of the GWP used for reporting under the Kyoto Protocol, reduces overall emissions by just under 1%, and use of the higher GWP suggested by Howarth et al (2011), increase the estimate of overall emissions by 1.6% in the base case and 1.8% in the venting scenario where methane emissions are higher.

Table 24: Influence of GWP for methane on lifecycle emissions for electricity generation from shale gas (g CO_2/kWh electricity)

	GWP of 25	GWP of 21	GWP of 33
	g $CO_{2\ eq}$/kWh	g $CO_{2\ eq}$/kWh	g $CO_{2\ eq}$/kWh
Base Case	422.4	419.0	429.3
Venting	424.7	420.9	432.4
Worst case	472.3	464.0	489.1

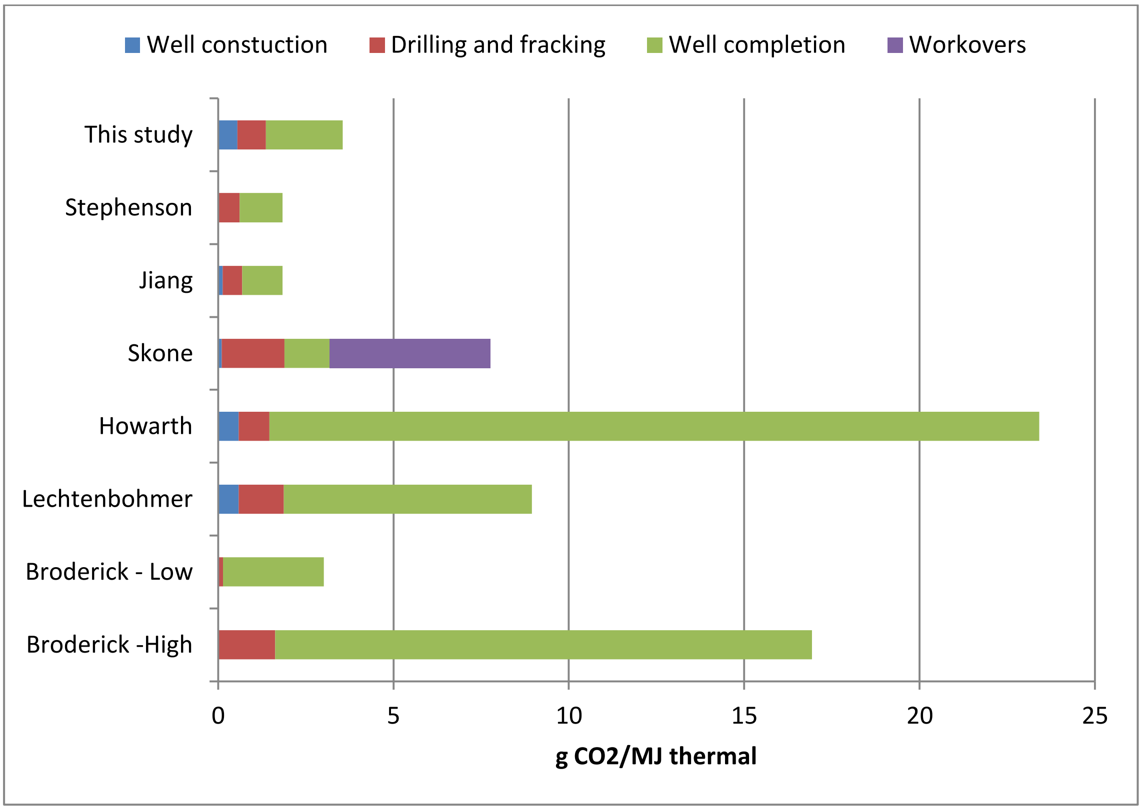
It is also interesting to compare the results from this study with the results from those studies reviewed in Chapter 3.

The results for the base case for the pre-production stages are shown in Figure 9, alongside the results for the base cases in the other studies reviewed in Chapter 3. This study estimates lifecycle emissions for these stages which are within the range of those forecast in other studies. There are however some differences:

- Emissions from site preparation are larger than in some studies, and similar to others. This reflects the conservative assumptions that have been applied (e.g. on emissions from land clearance).
- Emissions from transport are comparable, but at the lower end of other studies. This is due partly to the shorter transport distances assumed in the current study, based on the premise that exploitation sites in Europe are likely to be less remote than in the U.S.
- Emissions from waste water treatment are comparable with one study (Broderick et al, 2011), but lower than the other (Jiang et al, 2011). Overall the contribution of this stage is small in all studies, although further research may be needed on emissions associated with treatment.

- For emissions from flow back, during well completion, which is the biggest contribution to pre-production emissions our values are smaller than in some other studies, notably Howarth et al (2011). However, our estimate is in line with the latest EPA (2012b) analysis on total emissions per well completion, and applies conservative assumptions (85% vented) on the control of these emissions.

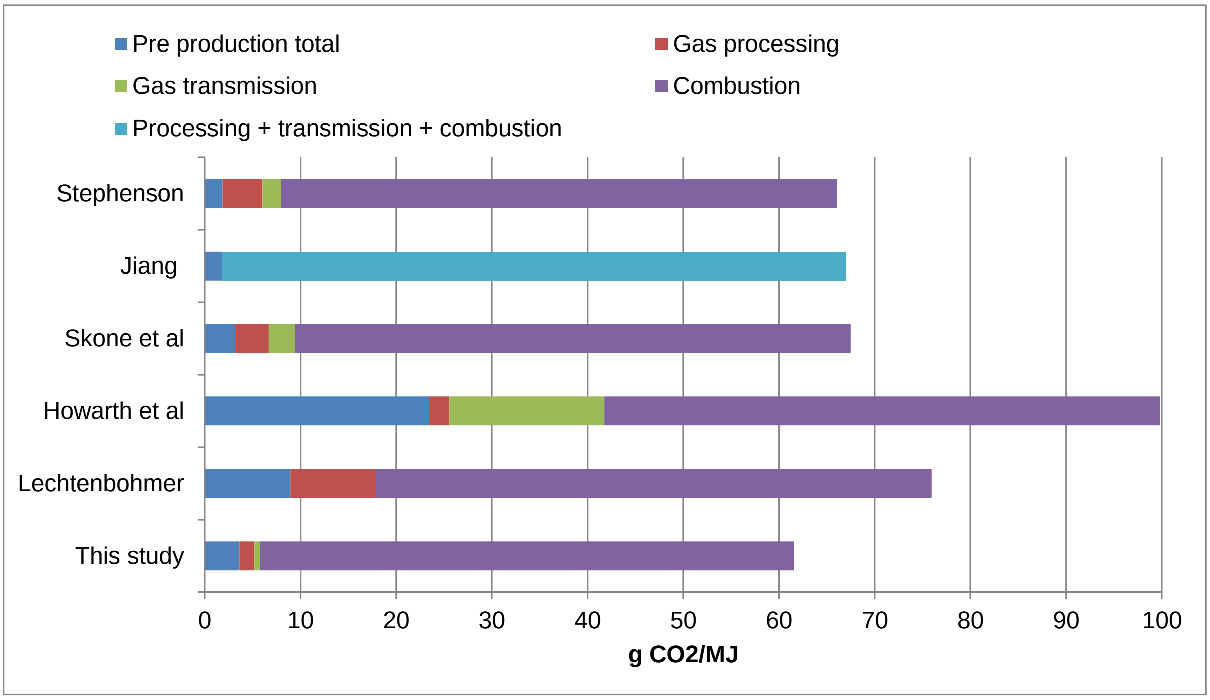
Figure 9: Comparison of lifecycle GHG emissions from pre-production stages for shale gas from this study and others



Note: Not all studies are fully independent of each other. For example, the Broderick and Lechtenbohmer estimates draw upon data from the Howarth study on emissions from well completions.

Our estimate of emissions from the total lifecycle is compared with the base cases of other studies reviewed in Figure 10. It is noticeable that emissions from gas treatment and processing and transmission are significantly lower than in the other studies. The emissions for these stages in this study are based on estimated emissions for these stages for conventional gas based in the UK; values in the other studies are typically based on average values for treatment, processing and transmission of conventional natural gas in the U.S. It is likely that this difference reflects differences in practices and mitigation techniques between the two regions. While it affects the absolute value of the lifecycle emission estimated for shale gas, the difference is not material when comparing shale gas with conventional gas, as in all of the studies, the same (region appropriate) value is used for both the shale gas and conventional gas cycle.

Figure 10: Comparison of lifecycle GHG emissions for shale gas from this study and others

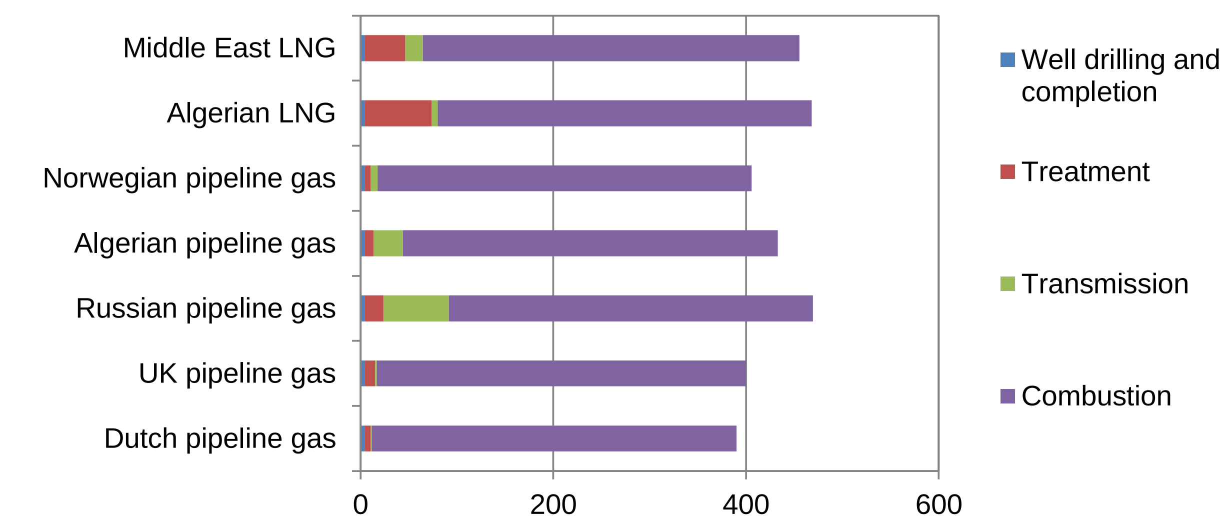


5.3.6.2 *Conventional gas*

The overall emissions from conventional gas are of an overall magnitude that is similar to shale gas and in some cases greater depending upon the supply source. The total lifecycle emissions range from 390 to 470 gCO_2eq/kWh, as shown in Figure 11

Since the production and transmission stage assumed in the shale gas results are based on the conditions in the United Kingdom, then this is the most equal comparison. Emissions from electricity production from conventional gas are estimated to be just less than 400 gCO_2eq/kWh. This suggests that the additional emissions from shale gas are between 9 and 72 gCO2eq/kWh. However, for other supply sources the relative differences will be less, and in some cases emissions from sources outside of Europe may exceed emissions from within Europe.

Figure 11: Total emissions from conventional gas (g/kWhe)



In all cases, the combustion of natural gas has the greatest contribution to the overall emissions in all cases.

In the case of natural gas from the Middle East, the gas needs to be further processed to produce liquid natural gas requiring additional energy. Also, the impacts of transport are quite high as the LNG needs to be transported via LNG tanker around Africa to Europe.

The emissions associated with Russian gas are also quite high, largely due to the high contribution of transport. This is primarily due to transport over long distances at high pressure in combination with pipeline leakages, more leakages occur due to poorly maintained compression stations and turbines in combination with the fact that Russian gas requires more drying to prevent pipe corrosion.

Natural gas from the Netherlands originates primarily from onshore wells in the province of Groningen, which borders the North Sea. The processing of the natural gas has relatively low GHG impacts compared to other countries as a result of energy savings achieved through a national long term agreement for efficient industry and mining. Transportation impacts are relatively small due to low compression energy demands and short transport distances. The high methane content of the natural gas also results in fewer GHG emissions from combustion.

Norwegian natural gas wells are located along the coastline in the North Sea. Similarly to natural gas from the Netherlands, Norwegian natural gas is processed using efficient best available technology. This results in relatively low GHG emissions per kWh. The transport distances, however, are greater for the supply of natural gas to continental Europe and as such the GHG impacts for transportation are greater. Norwegian natural gas also results in slightly more combustion emissions per kWh than Dutch natural gas as a result of different gas composition.

Algerian natural gas is pumped from onshore wells throughout the country. The processing of natural gas occurs fairly efficiently compared to that of natural gas from other non-European countries. However, the transportation of natural gas through pipelines has a relatively high GHG impact due to the underwater pipeline, which requires high pressures to compensate a lack of compression stations along the Mediterranean Sea portion of the pipeline. As with Norwegian pipeline gas and Middle Eastern LNG, the GHG emissions per kWh from combustion are quite high.

5.4 Coal Cycle

In order to allow a comparison with other forms of power generation, we have also produced estimates of the lifecycle emissions from coal generation based on data in the Ecoinvent lifecycle database.

Uncertainties and variations in data are discussed in EcoInvent's background report on coal.

5.4.1 Mining, preparation and shipping

Coal is mined in both opencast and underground mines. In underground mines associated methane rich mine gas is partly utilized in mining processes for onsite heat and power generation. Another fraction is vented to air as part of ventilation air from the mine.

Mined coal is ground and upgraded in the vicinity of the mine. Coal directly from the mine (also known as ROM - run-of-mine) contains unwanted ingredients such as pyrite and gangue. For the removal of these deficiencies and in order to meet power plant client specifications the ROM is broken and separated by screening into different fractions. The different fractions are purified applying gravity separation technologies such as jigging, gravity separation baths and cyclones. The purified particles are dewatered applying screens and centrifuges.

After transport to the port by truck (sometimes pipeline or train), the coal is shipped with bulk carriers to the customer.

The main GHG emission sources in mining and transport include diffuse methane emissions and CO_2 emissions from combustion of fuels for onsite heat and power generation and transports of run-of-mine coal and upgraded coal.

At the power station, the coal is micronized and pneumatically injected with combustion air into the boiler. Radiation and sensible heat of the combustion is used for production of super critical or ultra super critical steam, which is next utilized for driving a sequence of steam turbines before being condensed.

5.4.2 Power generation

Current state of the art power plants have net electric efficiencies of up to 48% (e.g. Avedoere II in Copenhagen). Technological developments aim at reaching efficiencies of 50% and higher. In the current analysis electrical efficiencies of 48% has been assumed across all scenarios.

Next to the CO_2 produced during coal combustion some additional GHG emissions are produced, related to the use of lime stone and ammonia in flue gas cleaning.

5.4.3 Results

Total emissions per kWh of electricity delivered to the grid are given in Table 25, assuming a net power plant efficiency of 48%.

Table 25: Lifecycle emissions from coal fired electricity generation (g CO_2eq/kWh)

	Russia	South Africa	South America
Mining + upgrading	107	37	8
Transport	0.3	1	1
Power station	721	731	706
Total	828	768	714

Source: based on the EcoInvent database

South American coal has the lowest GHG impact of three two types of coal. The non-combustion impacts are practically negligible compared to those for other coal types. Coal mining in Columbia (the highest coal producing country in South America) in practice takes place in both underground mines and open-pit mines (approximately 50% of total production). The Included EcoInvent data however include only data for underground mines. These mines produce little mine gas as half of the gas is captured for use as fuel. The transport of coal from South America is very efficient and results in a low GHG impact. The coal is transported in bulk carrier ships with an average capacity of 60kton. The GHG emissions resulting from the combustion of South American coal is high, as a result of a high carbon intensity.

South African coal has a slightly larger overall GHG impact than (underground) South American coal and the non-combustion GHG impacts are greater. Half of the mine gas is captured in South African coal mines, however due to greater methane emissions the GHG impact of the mining phase is relatively large. The transportation of coal from South Africa takes place very efficiently, by means of bulk carrier ship.

Russia has the largest coal impact, mostly due to the extraction phase of the lifecycle. The high GHG emissions are as a result of two-thirds of the coal being underground. For this reason, a large amount of mine gas is produced. In addition, the processing of Russian coal has quite high impacts as a result of a high energy use. Since Ecoinvent was used as a source for GHG impacts, it is unknown why the energy use is so high.

5.5 Summary

The main source of GHG emissions associated with shale gas exploitation have been identified and analysed. Overall, the emissions from shale gas are dominated by the combustion stage. However, emissions also arise from the pre-production, production, processing and transmission stages, but overall the significance of these stages is less. Emissions from exploration have not been taken into account within the analysis.

Of these pre-combustion stages, the most significant source of emissions are well completion and gas treatment, which account for 39% and 27% of pre-combustion emissions respectively in the base case of this hypothetical exercise. If flaring of flow back gases or green completion is assumed however, then the significance of the well completion stage falls significantly, only accounting for between 7% and 14% of pre-combustion emissions. Less significant sources are activities associated with well drilling and gas transmission, both of which account for about 10% of emissions in the base case.

Figure 12 shows the range of lifecycle emissions estimated for shale gas, against those for conventional pipeline gas (from within and outside Europe) and for LNG.

For the base case considered for shale gas, the GHG's per unit of electricity generated are around 4% to 8% higher than for electricity generated by conventional pipeline gas from within Europe. If emissions from well completion are mitigated, through flaring, or capture and utilisation then this difference is reduced (1% to 5%). This finding is broadly in line with those of other U.S. studies, which found that generation from shale gas had emissions between 2% to 3% higher than conventional pipeline gas generation.

This study also considered sources of gas outside of Europe, which make a significant contribution to European gas supply. Based on this hypothetical exercise, and drawing upon existing LCA studies for conventional sources, the analysis suggests that that the emissions from shale gas generation (base case) are 2% to 10% lower than emissions from electricity generated from sources of conventional pipeline gas located outside of Europe (in Russia and Algeria), and 7% to 10% lower than electricity generated from LNG imported into Europe[25].

However, this conclusion is far from clear-cut. Under the 'worst' case scenario, where all flow back gases at well completion are vented, emissions from electricity generated from shale gas would be at a similar level of the upper emissions level for electricity generated from imported LNG, and for gas imported from Russia. This suggests where emissions from shale gas are uncontrolled, there may be no GHG emission benefits from utilising domestic shale gas resources over imports of conventional gas from outside the EU. In fact, for some pipeline sources, emissions from shale gas may exceed emissions from importing conventional gas.

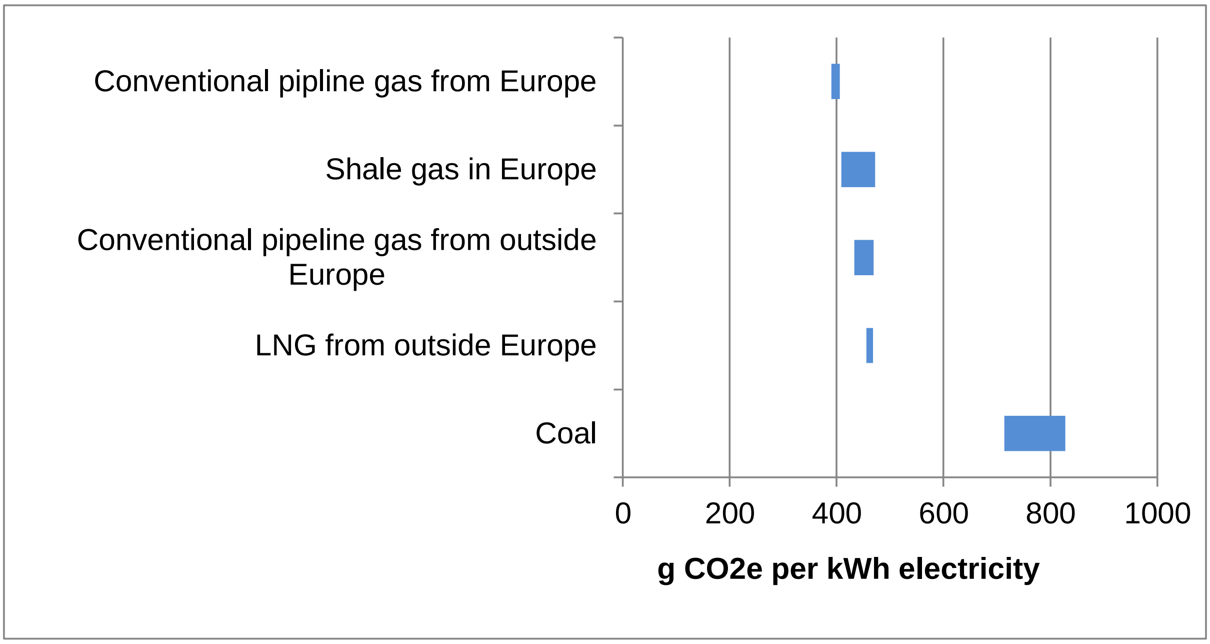
Emissions from shale gas generation are significantly lower (41% to 49%) than emissions from electricity generated from coal. This is on the basis of methane having a 100 year GWP of 25. This finding is consistent with those in most other studies.

These conclusions are based on experiences largely drawn from the U.S. Whilst attempts have been made to take into account the different circumstances in Europe, and how this may influence the overall emissions, this comparison is still largely hypothetical. Where the shale gas industry develops in Europe, this information should be used to update the results of the analysis.

These results can also be used to inform future discussions on the potential role of shale gas in the future energy supply mix. It has not been the aim of this study to explore this issue specifically, or related issues surrounding the potential implications of exploitation of indigenous shale gas resources on the development of renewable or other energy sources in Europe. These issues are important considerations for energy and climate policy makers, but are beyond the scope of this study.

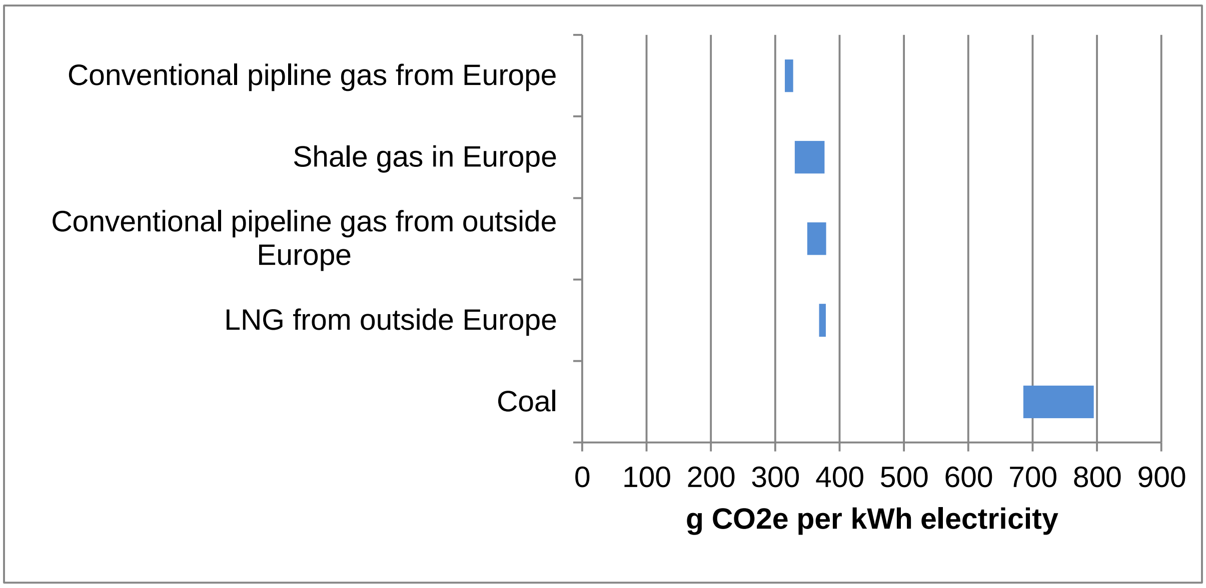
[25] When reporting emission on a production basis (as is the case with national emissions inventories under the United Nations Framework on Climate Change), emissions arising from shale gas operation within Europe will be captured within the EU's GHG emission inventory. However, emissions from e.g. conventional gas processing outside of Europe will not be accounted for in the EU's GHG inventory – and instead will be captured in the inventory of the regions in which they are produced.

Figure 12: Lifecycle emissions from coal and gas fired electricity generation



In the future, the electrical efficiency of new gas and coal power stations is expected to improve, as described in the previous sections. Improvements in efficiency will reduce the relative emissions from the combustion of gas and coal in these power stations. Efficiency improvement in gas-fired power stations will affect emissions from shale and conventional sources equally, as only the combustion step is affected. In Figure 13 the lifecycle emissions from coal and gas fired electricity generation are calculated on the basis of the high electrical efficiencies (65% for gas, 50% for coal) that might be possible in the future. The estimates do not take into account any other technology improvements, such as the application of carbon capture technologies. Clearly the application of abatement measures of the kind will have a significant impact on the overall GHG emissions (from the combustion stage) from both conventional and unconventional sources.

Figure 13: Lifecycle emissions from coal and gas fired electricity generation, with future improvements in electrical efficiency



6 Legislation controlling GHG emissions from shale gas production

6.1 Introduction

This chapter builds upon previous sections within this report to provide an examination of the suitability of different EU legislation for controlling the potential GHG emissions from shale gas production. Specific attention is given to policies which could enforce the use of most advanced technologies and practices designed to minimise potential GHG emissions.

The analysis has included the following:

- An initial review of existing legislation relevant to the exploitation of shale gas reserves. A brief overview is given for a range of relevant legislation and more detailed analysis carried out for a narrower set of the most relevant legislation.
- An exploration using case studies of the implementation of key directives within selected Member States (Poland, the UK and France).

For both of these activities the focus is on the well completion stage given the relative importance of this in terms of GHG emissions.

The analysis also includes a brief summary of the precedents set for emissions related to activities such as flaring and vented CO_2 emissions from enhanced hydrocarbon recovery in the EU Emission Trading System (EU ETS).

6.2 Initial review of existing legislation

This overview of the existing EU legislation relevant to exploitation of shale gas reserves focuses on EU legislation identified as relevant in two other documents, as detailed below. It should be noted that the documents have only been used for the selection of relevant EU legal acts and not for the analysis itself as they do not directly cover GHG emissions at a level of detail necessary for this work:

Source 1: "European Commission Guidance note on the applicable EU environmental legislation to unconventional hydrocarbon projects using advanced technologies such as horizontal drilling and high volume hydraulic fracturing.

This guidance document identifies eight pieces of EU environmental legislation applicable to shale gas projects, and provides a brief commentary on these with the European Commission's interpretation. It has a direct relevance for applicable EU environmental legislation, therefore many of the identified pieces of legislation may have relevance to GHGs and thus to this project. The list of eight is:

- EIA Directives (85/337/EC and 2011/92/EU): Council Directive of 27 June 1985 on the assessment of the effects of certain public and private projects on the environment, *1985L0337* and Directive 2011/92/EU of The European Parliament and of The Council of 13 December 2011 on the assessment of the effects of certain public and private projects on the environment, *OJ L 26/1, 28.1.2012.*

- Mining Waste Directive: Directive 2006/21/EC of The European Parliament and of The Council of 15 March 2006 on the management of waste from extractive industries and amending Directive 2004/35/EC, *OJ L 102/15, 11.4.2006.*

- Water Framework Directive: Directive 2000/60/EC of the European Parliament and of the Council of 23 October 2000 establishing a framework for Community action in the field of water policy *OJ L 327, 22.12.2000.*

- REACH Regulation: Regulation (EC) No 1907/2006 of the European Parliament and of the Council of 18 December 2006 concerning the Registration, Evaluation, Authorisation and

Restriction of Chemicals (REACH), establishing a European Chemicals Agency [etc], *OJ L 396, 30.12.2006.*

- Biocidal Products Directive: Directive 98/8/EC of the European Parliament and of the Council of 16 February 1998 concerning the placing of biocidal products on the market, *OJ L 123, 24.4.1998.*
- SEVESO II Directive: Council Directive 96/82/EC of 9 December 1996 on the control of major-accident hazards involving dangerous substances, *OJ L 010, 14/01/1997.*
- Habitats Directive: Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora, *OJ L 206, 22/07/1992.*
- Environmental Liability Directive: Directive 2004/35/CE of the European Parliament and of the Council of 21 April 2004 on environmental liability with regard to the prevention and remedying of environmental damage *OJ L 143, 30/04/2004.*

Source 2: The Final report on Unconventional Gas in Europe prepared by Philippe and Partners November 2011.

This report provides information, based on a sample of four Member States (France, Germany, Poland and Sweden) on current shale gas related licensing and permitting procedures. It has a much wider scope than just GHGs. Most national legislation originates at EU level. The potentially important EU legislation identified in Source 2, in addition to those listed in Source 1 is:

- Directive 94/22/EC of the European Parliament and the Council of 30 May 1994 on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons, OJ L 164, 30.06.1994.
- Directive 2001/81/EC of the European Parliament and of the Council of 23 October 2001 on national emission ceilings for certain atmospheric pollutants, OJ L 309, 27.11.2001.
- Council Directive 92/91/EEC of 3 November 1992 concerning the minimum requirements for improving the safety and health protection of workers in the mineral- extracting industries through drilling OJ L 348, 28.11.1992.

In addition to the above we have also considered the application of the Industrial Emissions Directive 2010/75/EU, which entered into force on 6th January 2011. This has to be transposed into national legislation by Member States by 7th January 2013.

The review in this chapter serves two main aims:

- To identify those texts / policy instruments which are relevant to GHG emissions from shale gas exploitation (i.e. the topic of this study);
- To provide focus for the case studies, which look at the implementation of certain relevant EU legislation in three Member States: France, Poland and the UK. The case studies focus on the national arrangements for regulation of GHGs as they apply to shale gas. It highlights corresponding differences between Member States and certain pieces of EU Legislation (mentioned below). It is not a detailed assessment of the transposition of that EU legislation.

Section 6.2.1 presents a brief overview of the directives and regulations identified above. Section 6.2.2 reviews three directives in more detail, which have been considered as particularly relevant or potentially relevant as regards GHG emissions: the EIA Directive, the Industrial Emissions Directive and the Health and Safety of Workers in the Mineral Extracting Industries through Drilling Directive. The EU ETS directive is also reviewed from the perspective of the examples it sets for the regulation of venting and flaring. It is noted that direct emissions from shale gas projects would not be covered by the EU ETS. The final part of this section presents the main conclusions relevant for the country case studies.

6.2.1 General Overview

This overview is focused primarily on the scope of the different legal acts that have been considered. Given the focus of this project on GHG emissions, a number of these have been deemed not relevant.

EIA Directive 85/337/EEC; 2011/92/EU (codified)

Pursuant to the EIA Directive, an Environmental Impact Assessment (EIA) is mandatory for unconventional / shale gas projects falling within Annex I.14 (extraction of natural gas where the amount of gas extracted exceeds 500,000 m³ per day). For projects below this threshold (e.g. those mentioned in Annex II.2.d or II.2.e), a screening is required, in accordance with Articles 2(1), 4(2)-(4) and Annex III of the EIA Directive. Projects related to the exploration of unconventional / shale gas are also subject to the requirements of the EIA Directive (European Commission, 2011). The EIA Directive does not contain any provisions relating specifically to GHG emissions. However, these would be considered to be part of the identification and assessment of particular estimates of expected emissions.

Industrial Emissions Directive (2010/75/EU)

The Industrial Emissions Directive does not explicitly mention that it covers shale gas exploration and exploitation activities. However, these activities could generate hazardous waste and thus fall under Sections 5.1 5.5 or 5.6 to Annex I to the Directive, or would potentially be covered by Section 1 to Annex I under specific circumstances related to their combustion capacity[26]. This would mean that the general requirements of this Directive could apply to these activities. The Directive requires that measures are set in the permit on emission limit values for certain polluting substances listed in Annex II, and for other polluting substances which are likely to be emitted from the installation concerned in significant quantities, having regards to their nature and their potential to transfer pollution from one medium to another. Substances listed in Annex II do not include methane. Methane could however be considered as a polluting substance which is likely to be emitted from the installation concerned in significant quantities that would require specific emission limit measures.

National Emission Ceilings Directive (2001/81/EC)

The NEC Directive set upper limits for each Member State for the total emissions in 2010 of the four pollutants responsible for acidification, eutrophication and ground-level ozone pollution (sulphur dioxide, nitrogen oxides, volatile organic compounds and ammonia). The Directive requires Member States to draw up programmes in order to reduce these emissions, to ensure that the limits are complied with and that emission ceilings for these pollutants are not exceeded in any year after 2010. The Directive leaves it largely to the Member States to decide which measures (on top of Community legislation for specific source categories) to take in order to comply with these limits.

The EU legislation that could apply to unconventional / shale gas projects, but that are not directly relevant to regulate GHG emissions as they do not include any provision specific to GHGs, are summarised below:

REACH Regulation (1907-2006/EC)	Operators of shale gas projects are considered downstream-users of chemical substances under REACH. To that end they must be provided with a safety data sheet that includes information on how they must use these substances.
Habitats Directive (92/43/EEC)	Shale gas projects would be prohibited in special areas of conservation unless it is demonstrated that here are imperative reasons of overriding public interest.
Biocidal Products Directive (98/8/EC)	Only biocidal products authorised under the Biocidal Product Directive can be used for shale gas exploration and exploitation.
Mining Waste Directive (2006/21/EC)	The mining waste Directive applies to waste derived from the exploration and exploitation of shale gas. It requires the set-up of a waste management plan. Gaseous emissions are excluded from the definition of waste and therefore the management of these would not be covered by measures under the Mining Waste Directive.
Water Framework Directive	Pursuant to this Directive, operators of shale gas exploration and exploitation activities must be granted an authorisation for

[26] In case the following conditions would apply: a combustion plant of at least 50 MW or another activity (e.g. gas refinery) listed in Annex I of the Industrial Emissions Directive (i) would be directly associated to shale gas exploration and exploitation, (ii) would have a technical connection with shale gas exploration and exploitation and (iii) would be operated in situ.

(2000/60/EC)	abstraction of fresh surface water and groundwater and impoundment of fresh surface water. This Directive prohibits discharges of pollutants into groundwater and the injection of water from exploration and extraction of hydrocarbon or mining activities (provided that such injections do not contain substances other than those resulting from such operations) is subject to authorisations by Member States. The application of this to flowback water is beyond this report, since it does not significantly affect the GHG emissions from shale gas exploitation
Hydrocarbons Directive (94/22/EC)	The Hydrocarbons Directive sets common rules among Member States to ensure non-discriminatory procedures for granting authorisations for access to the activities of prospection, exploration and production of hydrocarbons, which include shale gas activities.
Directive concerning minimum requirements for improving health and safety of workers in the mineral-extracting industries through drilling (Directive 92/91/EEC)	This Directive sets requirements to protect workers from harmful and explosive atmospheres. These requirements can indirectly and potentially control the air emissions of methane at the project site even though it is not the aim of this Directive.

6.2.2 Detailed analysis of key directives

This section provides further detail on the EIA Directive (85/337/EEC; 2011/92/EU (codified)), the Industrial Emissions Directive (2010/75/EU) and the Directive concerning minimum requirements for improving health and safety of workers in the mineral-extracting industries through drilling (Directive 92/91/EEC), focusing on their direct application to GHG emissions from shale gas extraction projects. We also examine the EU ETS Directive (2003/87/EC) with regards to the precedents that it could set for future regulation of GHG sources from hydraulic fracturing (hydraulic fracturing is not covered by the EU ETS).

6.2.2.1 *EIA Directive 85/337/EEC; 2011/92/EU (codified)*

The EIA Directive requires that public and private projects likely to have significant effects on the environment should be subject to an EIA. The main requirement of an EIA is to identify, describe and assess the direct and indirect effects of the project on different factors of the environment, including air and climate, and the interaction between those factors (Article 3).

The Directive distinguishes between those projects subject to a mandatory EIA and those projects which are determined by Member States as requiring an EIA (Art 4). A mandatory EIA is required for all projects listed in Annex I, which are considered as having significant effects on the environment. These include unconventional / shale gas projects which fall within Annex I.14 (extraction of natural gas where the amount of gas extracted exceeds 500,000 m³ per day).

Other projects, listed in Annex II are not required to be automatically assessed. Instead, Member States are required to screen such projects, to determine whether an EIA should be carried out. The determination must be made either on a case by case basis or according to thresholds or criteria, taking into account specific selection criteria, including the project's characteristics (e.g. size, pollution), location (including environmental sensitivity of the local area) and potential impact (e.g. geographical area affected and duration). Projects falling within Annex II include those associated with the extractive industry (e.g. "deep drillings" (Annex II.2.d) and surface industrial installations for the extraction of natural gas (Annex II.2.e)), the energy industry (e.g. industrial installations for carrying gas, and surface storage of natural gas and fossil fuels) and infrastructure projects (e.g. oil and gas pipeline installations).

The European Commission has confirmed that the EIA Directive would apply to those unconventional / shale gas activities falling within Annex I.14 and that, where such projects fall below the threshold in Annex I.14, a screening would be required in accordance with Articles 2(1), 4(2)-(4) and Annex III of the Directive. It also confirmed that projects related to exploration or unconventional / shale gas would be subject to the requirements of the Directive, noting that Annex II.2 refers to *"deep drillings"* and provided the view that the list of activities associated with deep drillings, which does not include shale gas extraction, is non-exhaustive. The European Commission also underlined the need for the precautionary principle to be taken into account in deciding whether an EIA is needed, indicating that shale gas projects would be subject to an EIA if it could not be excluded (on the basis of objective information) that the project would have significant environmental effects. It concluded that the precautionary principle implied that in case of doubts as to the absence of significant effects, an EIA must be carried out (European Commission, 2011).

The study commissioned by the European Parliament has expressed concern over the threshold set by the EIA Directive, noting that current exploitation of shale gas is considerably lower than the minimum threshold required for a mandatory EIA to be carried out. It recommends that projects including hydraulic fracturing should either be added to Annex I independently of a production threshold or else the threshold value should be lowered in order to close the gap.

It is also important to note that the EIA Directive does not contain specific provisions relating to GHG emissions from projects. Instead, it requires Member states, *inter alia,* to ensure that developers supply certain information, such as a description of estimated air emissions and significant environmental impacts resulting from the project, including air and climatic factors in the framework of a full EIA. Furthermore, the Directive provides for competent authorities to give an opinion on the information supplied, which, as a minimum should include, *inter alia,* a description of the measures envisaged in order to avoid, reduce and if possible, remedy significant adverse side effects. These, along with other requirements, will be considered in more detail below.

Impact Assessments

Pursuant to Article 5(1), in the case of a full EIA, Member States are required to adopt necessary measures to ensure that project developers supply specific information as listed in Annex IV. This information includes an estimate of expected emissions (including air emissions) resulting from the operation of the proposed project; and a description of the aspects of the environment likely to be significantly affected by the proposed project (including climatic factors and interrelationships between all factors considered). It also includes a description of the direct and indirect, secondary, cumulative, short, medium and long-term, permanent and temporary, positive and negative effects of the project, using forecasting methods which must be described by the developer.

Member States should adopt these measures to the extent that such information is relevant, *inter alia,* to the specific characteristics of the environmental features likely to be affected; and they consider that a developer may reasonably be required to compile this information having regard, *inter alia,* to 'current knowledge and methods of assessment'. Due to its uncertainty this wording may create problems as far as consideration of impact on GHG emissions is concerned.

Technology requirements

While the EIA Directive does not provide for specific technological requirements, Article 5(2) provides for Member States to ensure that, if the developer so requests before submitting an application for development consent, the competent authority shall give an opinion on the information to be supplied by the developer in accordance with Article 5(1). As a minimum the supplied information must include, *inter alia,* a description of the measures envisaged in order to avoid, reduce and if possible, remedy significant adverse side effects, as well as the main alternatives studied by the developer. These could potentially include technological solutions as are deemed necessary to reduce GHG emissions.

Consultation process

Article 6 of the EIA Directive provides that authorities likely to be concerned by a project must be given an opportunity to express their opinion on the information supplied by the developer under Article 5 and on the request for development consent. This could potentially include those authorities concerned with GHG emissions and climate change. Article 6 also provides for public consultation early in the environmental decision-making procedures. Furthermore, Article 11 requires Member States to ensure that members of the public, who have "sufficient interest" or are "maintaining the impairment of a right", have access to a review procedure to challenge the substantive or procedural legality of decisions, acts or omissions. What constitutes "sufficient interest" and "maintaining the impairment of a right" is to be determined by Member States. This, arguably, leaves scope for interpretation. Access to review procedures should be open to the general public and NGOs which promote environmental protection and meet the requirements under national law.

Article 7 provides that where a Member State is aware that a project is likely to have significant effects on the environment in another Member State, or where a Member State is likely to be affected, the Member State shall send a description of the project including, *inter alia,* available information on its trans-boundary impact. Article 7 also requires the Member States concerned to arrange for that information to be sent to the authorities specified in Article 6 (as mentioned above).

Licensing / authorisation requirements

As stated above, EIAs are an inherent part of the development consent process and for applicable activities, consent must not be granted until all necessary measures are taken to identify, describe and assess the direct and indirect effects of the project on the environment.

Other issues

Confidentiality

Article 10 provides that competent authorities must respect the limitation imposed by national laws, regulations and accepted legal practices with regard to commercial and industrial confidentiality. This may have important consequences with regard to information which may be relevant to GHG emissions.

6.2.2.2 *Industrial Emissions Directive 2010/75/EU*

Directive 2010/75/EU lays down rules on integrated prevention and control of pollution arising from industrial activities. This Directive is a recast of the following Directives:

- Directive 2000/76/EC on the incineration of waste;
- Directive 2001/80/EC on the limitation of emissions from large combustion plants;
- Directive 2008/1/EC concerning integrated pollution and prevention and control;
- Directives 78/176/EEC, 82/883/EEC and 92/112/EEC on waste from the titanium dioxide industry.

The purpose of this Directive is to achieve a high level of protection of the environment taken as a whole from the harmful effects of industrial activities. To that end it sets some requirements that must be applied to industrial installations set in Annex I to the Directive and specific measures for combustion plants and waste (co)-incineration plants.

Operators of industrial activities listed in Annex I to the Directive must obtain an integrated permit from relevant national authorities prior to operation. All of the related environmental impacts of these activities (e.g. pollution caused, generation of waste, energy efficiency, and emissions to air) must be taken into consideration for the issuance of the permit. Furthermore the permit conditions (e.g. emission limit values) must be based on the Best Available Techniques as defined in Article 3(10) of the Directive.

Annex I to this Directive does not explicitly refer to unconventional hydrocarbon exploration and exploitation activities as it does not refer to mining activities in general.

Section 5.1 of Annex I covers disposal or recovery of hazardous waste with a capacity exceeding 10 tonnes per day involving several types of activities (e.g. surface impoundment), Section 5.5 of that Annex covers temporary storage of hazardous wastes listed under Section 5.1 with a total capacity exceeding 50 tonnes, excluding temporary storage pending collection on the site where the waste is generated and Section 5.6 of the Annex refers underground storage of hazardous waste with a total capacity exceeding 50 tonnes.

The criteria to define hazardous waste are set under Annex III to the Waste Framework Directive.

Criteria to define hazardous waste (Annex III Waste Framework Directive)

H 1 ‘Explosive’: substances and preparations which may explode under the effect of flame or which are more sensitive to shocks or friction than dinitrobenzene.

H 2 ‘Oxidizing’: substances and preparations which exhibit highly exothermic reactions when in contact with other substances, particularly flammable substances.

H 3-A ‘Highly flammable’.

— liquid substances and preparations having a flash point below 21 °C (including extremely flammable liquids); or

— substances and preparations which may become hot and finally catch fire in contact with air at ambient temperature without any application of energy; or

— solid substances and preparations which may readily catch fire after brief contact with a source of ignition and which continue to burn or to be consumed after removal of the source of ignition; or

— gaseous substances and preparations which are flammable in air at normal pressure; or

— substances and preparations which, in contact with water or damp air, evolve highly flammable gases in dangerous quantities.

H 3-B ‘Flammable’: liquid substances and preparations having a flash point equal to or greater than 21 °C and less than or equal to 55 °C.

H 4 ‘Irritant’: non-corrosive substances and preparations which, through immediate, prolonged or repeated contact with the skin or mucous membrane, can cause inflammation.

H 5 ‘Harmful’: substances and preparations which, if they are inhaled or ingested or if they penetrate the skin, may involve limited health risks.

H 6 ‘Toxic’: substances and preparations (including very toxic substances and preparations) which, if they are inhaled or ingested or if they penetrate the skin, may involve serious, acute or chronic health risks and even death.

H 7 ‘Carcinogenic’: substances and preparations which, if they are inhaled or ingested or if they penetrate the skin, may induce cancer or increase its incidence.

H 8 ‘Corrosive’: substances and preparations which may destroy living tissue on contact.

H 9 ‘Infectious’: substances and preparations containing viable micro-organisms or their toxins which are known or reliably believed to cause disease in man or other living organisms.

H 10 ‘Toxic for reproduction’: substances and preparations which, if they are inhaled or ingested or if they penetrate the skin, may induce non-hereditary congenital malformations or increase their incidence.

H 11 ‘Mutagenic’: substances and preparations which, if they are inhaled or ingested or if they penetrate the skin, may induce hereditary genetic defects or increase their incidence.

H 12 Waste which releases toxic or very toxic gases in contact with water, air or an acid.

H 13 ‘Sensitizing’: substances and preparations which, if they are inhaled or if they penetrate the skin, are capable of eliciting a reaction of hypersensitization such that on further exposure to the substance or preparation, characteristic adverse effects are produced.

H 14 ‘Ecotoxic’: waste which presents or may present immediate or delayed risks for one or more sectors of the environment.

According to several studies on hydraulic fracturing in the U.S.[27], certain chemicals used are known to be carcinogens, mutagens or are listed as hazardous pollutants under the U.S. Clean Air Act. Furthermore, methane is a gaseous substance which is flammable in air at normal pressure.

Therefore it would be possible that hazardous waste is generated during shale gas exploration and exploitation activities and that provided the threshold is fulfilled (disposal capacity exceeding 10 tons per day, capacity exceeding 50 tons for temporary storage and 50 tons for underground storage) their waste water disposal installations could thus fall under Annex I to the Industrial Emissions Directive. However shale gas activities would not fall under Sections 5.1, 5.5, 5.6 of Annex I if the storage of hazardous waste is temporary prior to being transferred to a waste treatment facility.

Furthermore it can also be interpreted that the Industrial Emissions Directive could apply to shale gas exploration and exploitation activities if a combustion plant of at least 50 MW or another activity (e.g. gas refinery) listed in Annex I of the Industrial Emissions Directive (i) would be directly associated to

[27] US House of Representatives Committee on Energy and Commerce, 2011 NPR and New York State DEC (2011 PR p5-54 onward

shale gas exploration and exploitation, (ii) would have a technical connection with shale gas exploration and exploitation and (iii) would be operated in situ.

Permits must be granted to Annex I installations subject to the compliance with certain conditions which include measures on emission limit values for polluting substances listed in Annex II to Directive 2010/75/EU[28] and for other polluting substances, which are likely to be emitted from the installation concerned in significant quantities, having regards to their nature and their potential to transfer pollution from one medium to another (Article 14(1) (a)). Substances listed in Annex II do not include methane. Methane could however be considered as a polluting substance which is likely to be emitted from the installation concerned in significant quantities that would thus require specific emission limit measures.

Overall the application of Directive 2010/75/EU to shale gas exploration and exploitation activities is subject to interpretation and requires a case by case approach. Furthermore it is not clear whether the emission limit value measures required under this Directive would apply to methane contained within flow back from these activities.

6.2.2.3 *Directive concerning minimum requirements for improving health and safety of workers in the mineral-extracting industries through drilling (Directive 92/91/EEC)*

Directive 92/91/EEC details the minimum requirements for improving the safety and health protection of workers in the mineral-extracting industries through drilling i.e. extraction of minerals (onshore and offshore) and preparation of extracted materials for sale. While the Directive does not contain any provisions specifically relating to GHG emissions it requires employers to take the necessary measures to ensure, *inter alia,* that workplaces are designed, constructed, equipped, commissioned, operated and maintained so that workers can perform their work without endangering their health and safety and those of others. It also requires employers to prevent the occurrence of health endangering atmospheres. It is an individual directive within the meaning of Directive 89/391/EEC (on the introduction of measures to encourage improvements in the safety and health of workers at work), for which Article 6 places a general obligation on employers to take measures necessary for the health and safety protection of workers.

Article 10, in conjunction with the Annex to the Directive, sets minimum requirements for health and safety in the workplace. These include the requirement for Member States to take measures for assessing the presence of harmful and / or potentially explosive substances in the atmosphere and for measuring the concentration of such substances. Paragraph 6.1 of the Annex requires that additional measures for monitoring devices measuring gas concentrations at specific places, as well as alarms and devices to cut off power, must also be provided but only “where required by the safety and health document”. Paragraph 6.2 requires “appropriate measures” to be taken to ensure collection at source and removal of harmful substances where they accumulate or may accumulate in the atmosphere, also requiring the system to be capable of dispersing such substances in such a way that workers are not at risk. Furthermore, appropriate and sufficient breathing and resuscitation equipment must be available in areas where workers must be exposed to atmospheres which are harmful to health.

This Directive does not define what covers harmful and / or potentially explosive substances. Methane, which is a flammable gas, could however be considered as a potentially explosive substance. The Directive’s focus is however on the protection of workers from harmful and / or explosive substances. It does not regulate the air emissions of methane even though the measures to protect workers from harmful and / or explosive substances could potentially and indirectly control the air emissions of methane. Pursuant to Annex Part B paragraph 2 of this Directive, systems for the isolation and blowdown of wells, plant and pipelines must be capable of remote control at suitable locations in the event of an emergency. This would limit the accidental air emissions and would potentially have an influence on the control of GHG emissions. This is however not relevant for this project, which does not cover abnormal situations.

[28] List of substances under Annex II to Directive 2010/75/EU: Sulphur dioxide and other sulphur compounds, Oxides of nitrogen and other nitrogen compounds, Carbon monoxide, Volatile organic compounds, Metals and their compounds, Dust including fine particulate matter, Asbestos (suspended particulates, fibres), Chlorine and its compounds, Fluorine and its compounds, Arsenic and its compounds, Cyanides, substances and mixtures which have been proved to possess carcinogenic or mutagenic properties or properties which may affect reproduction via the air, polychlorinated dibenzodioxins and polychlorinated dibenzofurans.

In general the provisions for the protection of workers will provide some protection for the wider public. However, since the legislation is not expressed in terms of public safety, it is not possible to conclude that it would adequately protect the public or control GHG emissions to any desired limit.

6.2.2.4 *Emissions Trading System (EU ETS) Directive 2003/87/EC*

This Directive establishes a system for GHG emissions trading, which began in 2005 and which has undergone several revisions since then. The Directive covers stationary installations and aircraft operators and is described here in the context of the former since this has the most direct potential relevance to shale gas exploitation sites.

The Directive covers stationary installations that carry out any activity listed in Annex I. Such installations must hold a GHG emissions permit (Article 4), monitor, have verified and report their GHG emissions (Articles 14 and 15), and acquire and surrender emissions allowances equal in quantity to the number of tonnes of carbon dioxide equivalent that they emit (Article 12).

Annex I does not contain any activities that would directly relate to the extraction of natural gas. The only potential means by which shale gas sites could be included in the system would be through the inclusion of the combustion of fuels in installations with a total rated thermal input exceeding 20MW. In this context Annex I states that the determination of total rated thermal input is to include, *inter alia*, engines and flares. Consequently a shale gas installation could in principle be included in the system because of these activities, although whether in practice the combustion capacity is likely to exceed that level is not known. Notably there is no mention in the Directive of including installations due to the GHG emissions arising from the venting of natural gas.

It is therefore assumed unlikely that shale gas extraction would be covered by the EU ETS, and the discussion below is intended to describe the EU ETS approach to venting and flaring as this may set examples for future regulation of shale gas emissions (either within or outside of the EU ETS).

In a similar way that flaring must be taken into account in determining whether an installation must be included in the system, it must also be reported as applicable for those that are included. To the end of December 2012 the rules for monitoring and reporting of emissions are set out in the Monitoring and Reporting Guidelines. However, from January 2013 two new Regulations for Monitoring and Reporting (M&RR) and for Verification and Accreditation will apply. The M&RR contains rules for flaring under the combustion processes activity (Annex IV subsection D). This requires the calculation of emissions from routine flaring and operational flaring, with a reference emission factor for lower volume flaring (lower emissions) and the requirement for an installation emission factor for higher volume flaring. Venting of certain process emissions are included for some activities, but it is not required to be monitored for combustion installations.

From the above, it can be seen that the EU ETS contains provisions for the inclusion of combustion installations including flaring, but not for venting of GHG emissions at those installations. With regards to a potential model for the regulation of fugitive emissions from hydraulic fracturing, examples can be taken from the Directive's treatment of capture and geological storage of carbon dioxide.

The Directive includes geological storage of GHGs in a storage site permitted under Directive 2009/31/EC. For pipelines for the transport of CO_2 and for storage the M&MR require the determination of fugitive and vented emissions as well as those from leakage events. For the storage site, vented and fugitive emissions must also be included. In cases of enhanced hydrocarbon recovery operations, emissions sources must also include oil-gas separation units and the flare stack and associated CO_2 purge systems. Whilst predominantly CO_2 sources, the treatment of emissions from venting, flaring, fugitive emissions and gas processing operations under the EU ETS could provide relevant examples for systems to regulate emissions arising at hydraulic fracturing sites.

6.2.3 General conclusions regarding the overview of legislation

In conclusion, the overview analysis of the EU legal acts identified as relevant to shale gas has shown that there are very few requirements applicable specifically to GHG emissions from shale gas projects.

The **EIA Directive (85/337/EEC; 2011/92/EU (codified))** is the most relevant as it sets requirements as to the consideration of climate change effects and air emissions as part of a full EIA. It requires Member States to ensure that developers supply certain information, such as a description of estimated air emissions and significant environmental impacts resulting from the project, including air and climatic factors. Furthermore the Directive provides for competent authorities to give an opinion on the information supplied which, as a minimum, should include a description of the measures envisaged in order to avoid, reduce and if possible, remedy significant adverse side effects.

However, despite these requirements, many uncertainties remain as to whether Member States would require an EIA for shale gas operations, and if so how Member States should implement the EIA, for example the methodology to be used to quantify GHG emissions baseline scenarios.

Directive 92/91/EEC concerning minimum requirements for improving health and safety of workers in the mineral-extracting industries through drilling does not contain any provisions specifically relating to GHG emissions from these activities. It does however set requirements to protect workers from harmful and / or explosive substances that would primarily apply to methane present in such concentration that it can represent a risk in terms of flammability for workers.

With regard to **the Directive on Industrial Emissions (2010/75/EU)** it is not clear in which circumstances it would apply to shale gas exploration and exploitation activities and whether its measures on air emissions would cover methane contained within flow back.

It is beyond the scope of the report to make specific recommendations on how to overcome the potential shortfalls identified above.

Finally, **the EU ETS Directive (Directive 2003/87/EC**) could provide precedents for the regulation of shale gas emissions, through its treatment of venting and flaring and emissions related to carbon capture and storage processes.

The legislation described above could provide an approach with which to enforce best shale gas technologies, although this would likely need to be supplemented by BAT reference documents, guidance specific to shale gas technologies and clarification on the applicability of key directives. In particular:

- Under the EIA Directive 85/337/EEC; 2011/92/EU (codified), the competent authority must, if requested, give an opinion on the measures envisaged in order to avoid, reduce and if possible, remedy significant adverse side effects. These could potentially include technological solutions as are deemed necessary to reduce GHG emissions, in line with best available technologies;
- Directive 92/91/EEC, concerning health and safety of workers in mineral extracting industries requires “appropriate measures” to be taken to ensure collection at source and removal of harmful substances where they accumulate or may accumulate in the atmosphere. These are not required to be BAT, but the legislation does appear suitable for prescribing use of certain technologies;
- The Industrial Emissions Directive 2010/75/EU requires permiting of eligible installations, for which conditions necessary to achieve a high level of environmental protection should be set on the basis of best available techniques. However, it is not clear if the directive would always apply to methane emissions from shale gas installations and there is no BAT reference document specific to shale gas extraction technologies.

As described above, there are approaches within existing legislation that are well aligned with applying best available technologies to shale gas technologies. Alternatives, such as voluntary agreements, could also be considered but additional measures would be required to ensure they are rigorously applied.

6.3 Case Studies

The following case studies examine regulatory frameworks for implementing the key Directives in three Member States. Taking into account the fact that, as mentioned above, the identified Directives have limited application to GHG emissions from shale gas activities the scope of the case studies looks more generally at any existing requirement and / or guidance that would apply at the EIA and authorisation stages. Particular attention was paid to requirements or guidance applicable to well completion, at the national level.

The case studies examine Member States’ implementation of the EIA Directive but also any requirement on GHG emissions as part of the authorisation process. The case studies do not constitute an assessment of the appropriateness of the transposition of the EU legislation into national law.

They also examine the associated national legislation for three countries, insofar as they could relate to GHG emissions. The UK, France and Poland were selected due to the contrast in their differing approaches and potential for shale gas production. Germany was also considered as a potential country but, due to the complexity of the legislation, it was decided it would not be included.

As part of the development of the case studies we approached at least one representative for each Member State to ask for an interview. In some instances they preferred to provide a written response to a pre-prepared interview questionnaire. The Member State representatives whose contribution is included in the case studies are:

Country	National regulator
France	Direction générale de la prévention des risques, Ministère de l'Ecologie: Ms Sophie Dehayes
Poland	Polish Environment Ministry department on mining concessions: Mr Bartosz Arabik
UK	Environment Agency of England and Wales: Martin Diaper Department of Environment Northern Ireland: Mark Livingstone

6.3.1 Case study: Legal requirements on the climate change impact of shale gas exploitation: United Kingdom

6.3.1.1 *Background information*

Shale gas exploration in the UK is still in its infancy. According to the UK authorities only one well has been hydraulically fractured to date, while about 10 have planning permission for site works but do not have permission for hydraulic fracturing. In light of this early stage of development the regulatory position for some aspects of on-shore unconventional gas are being reviewed and developed. Official estimates published by the Department of Energy and Climate Change (DECC) in 2010 indicated that up to 150 billion cubic metres (bcm) of shale gas could be available in the UK. However, more recent industry estimates indicate that over 5,000 billion cubic metres (bcm) of gas could lie in the Bowland shale under Lancashire in the North of England alone[29].

6.3.1.2 *Legal framework applicable to GHG emissions for the exploration and exploitation of shale gas in the UK*

There is no specific mention of shale gas, or unconventional gas, in the UK legislation. Rather, shale gas drilling in the UK is covered by the general provisions for oil and gas exploration and development activities. Furthermore, there are no requirements within these general provisions which specifically address GHG emissions. The regulation and control of GHG emissions from the production of unconventional gas is covered (albeit indirectly) by separate regimes for environmental control, health and safety and petroleum exploration and development. There are also local controls through land use planning. In addition, there are a number of legislative variations in the regulation of unconventional gas within each of the three main jurisdictions: (i) England and Wales; (ii) Scotland and (iii) Northern Ireland. This report will consider the main legislative and regulatory requirements within each of these jurisdictions.

GHG emissions related considerations in the oil and gas licencing in England, Scotland and Wales

Oil and gas licensing in England, Scotland and Wales is governed by the Petroleum Act 1998 (“the 1998 Act”), the Petroleum (Production) (Landward Areas) Regulations 1995 (“The 1995 Regulations”), and the Hydrocarbon Licensing Directive Regulations 1995 (“the Hydrocarbon Regulations”). The 1998 Act vests all rights and ownership of petroleum resources (oil and gas) to the UK government, which then grants a Petroleum Exploration and Development licence (PEDL) in competitive offering

[29] http://www.cuadrillaresources.com/benefits/jobs-and-investment/

(licensing rounds) for the exclusive exploration, development, production and abandonment of hydrocarbon in the licence area. This licence, issued by DECC, only allows a company to carry out various oil and gas exploration and exploitation activities, subject to all necessary drilling / development consents, planning permissions, health and safety and environmental requirements, as set out below. Before a licence can be awarded, the applicant must satisfy DECC of the technical competence and environmental awareness of its proposed operator, and each member of the applicant group must satisfy DECC of its financial viability and financial capacity. It should be noted that GHG emissions are not specifically taken into account in the licensing process.

As part of the licence application, applicants must submit an "Environmental Awareness Statement".

Information to be provided in the Environmental Awareness Statement:

- applicant's understanding of the UK's onshore environmental legislation relevant to the exploration, development and production stages of the project;
- applicant's understanding of the particular sensitivities associated with operational planning (e.g. Special Areas of Conservation (SACs), Special Protection Areas (SPAs), Marine Conservation Zone (MCZs), Marine Protected Areas (MPAs));
- details of their pollution liability arrangements and their commitment to environmental policy and management;
- details of any previous failure to comply with environmental standards or requirements within the previous five years (e.g. any civil or criminal action against the operator, or any convictions for breaches of environmental legislation.

It should be noted that DECC's criteria for assessing licence applications are published and do not involve assessment of the impacts of the proposed activities on the environment. So far as these impacts can be assessed at the stage of the issue of licences, they are covered by a "strategic environmental assessment" (SEA) which is carried out before applications for licences are invited. In accordance with Directive 2001/42/EC ("the SEA Directive"), the Environmental Assessment of Plans and Programmes Regulations 2004 and the Environmental Assessment (Scotland) Act 2005 require an environmental assessment to be carried out, which should include the preparation of an environmental report (regulation 12; Article 5 of the SEA Directive). The matters to be included in the environmental report are specified in Schedule 2 to the Regulations (Article 5.1 of, and Annex II to, the SEA Directive), details of which are set out below. At the licensing stage the impacts are only to be assessed at a generic level. It will however be noted that more detailed assessment of the possible impacts of the specific activities which the licensee may in due course wish to carry out will be performed at the stage of seeking planning permission for these activities, in those cases in which an EIA is required.

Matters to be included in the environmental report pursuant to the Environmental Assessment of Plans and Programmes Regulations 2004 and the Environmental Assessment (Scotland) Act 2005:

- An outline of the contents and main objectives of the plan or programme, and its relationship with other relevant plans and programmes;
- The relevant aspects of the current state of the environment and the likely evolution thereof without implementation of the plan or programme;
- The environmental characteristics of areas likely to be significantly affected;
- Any existing environmental problems which are relevant to the plan or programme including, in particular, those relating to any areas of a particular environmental importance, such as areas designated pursuant to Council Directive 79/409/EEC on the conservation of wild birds and the Habitats Directive;
- The environmental protection objectives, established at international, Community or Member State level, which are relevant to the plan or programme and the way those objectives and any environmental considerations have been taken into account during its preparation;

- The likely significant effects on the environment, including short, medium and long-term effects, permanent and temporary effects, positive and negative effects, and secondary, cumulative and synergistic effects, on issues such as biodiversity, human health, flora and fauna, air, climatic conditions, measures to prevent, reduce and as fully as possible offset any significant adverse effects on the environment.

GHG emissions related considerations in the planning permissions in England, Scotland and Wales

On being issued with a PEDL by DECC, the operator must obtain all relevant planning permissions and landowners' permissions before exploration in respect of any hydrocarbon development(s) can commence. Pursuant to Section 57 of the Town and Country Planning Act 1990 (England and Wales) as amended by the Planning Act 2008, planning permission is required from the Local Planning Authority (LPA) for the carrying out of any development of land. 'Development' includes the carrying out of building, engineering, mining or other operations in, on, over or under land. This includes drilling for the purposes of shale gas exploration and exploitation.

As part of the planning permission process, the LPA must determine if an EIA is required. The Town & Country Planning (Environmental Impact Assessment) Regulations 2011 and the Town & Country Planning (Environmental Impact Assessment) (Scotland) Regulations 2011 require an EIA to be carried out for developments in Schedule 1 of the Regulations and certain developments under Schedule 2 of the Regulations ('EIA Developments') where they are likely to have a significant impact on the environment. According to these Regulations an EIA is compulsory in case of extraction of petroleum and natural gas for commercial purposes, where the amount extracted exceeds 500 tonnes per day in the case of petroleum and 500,000 m^3 per day in the case of gas (schedule 1) and can be required after an environmental screening for any type of drilling where the area of the works exceeds 1 hectare (Schedule 2).

It is most likely that shale gas drilling operations would fall within the Schedule 2 category of 'deep drilling'. If the development falls within the criteria set out in Schedule 2 (drilling the area of the works exceeds 1 hectare), the development would be screened to assess whether or not it is likely to have significant effects on the environment and thus whether an EIA is required. The selection criteria for this screening process includes; consideration of the characteristics of the development (e.g. size, use of natural resources production of waste, pollution and nuisances); location of the development (e.g. existing land use and absorption capacity of the natural environment) and characteristics of the potential impact (e.g. extent, magnitude and complexity).

Information required in the Environmental Impact Assessment (Environmental Statement):

- A description of the development (including physical characteristics, production processes and an estimate of expected residues and emissions);
- An outline of the main alternatives and an indication of the main reasons for the choice made, taking into account the environmental effects;
- A description of those environmental aspects likely to be significantly affected by the development, including population, flora, fauna, soil, water, air and climatic factors;
- A description of the likely significant effects of the development on the environment, including direct, indirect, temporary and permanent effects.

GHG emissions relevant requirements for the drilling authorisation in England, Scotland and Wales

Once the minerals planning authority has granted permission to drill, DECC will consider an application to drill; and at least 21 days before drilling is planned, the Health and Safety Executive (HSE) must be notified of the well design and operational plans to ensure that major accident hazard risks to people from well and well-related activities are properly controlled, subject to the same regulation as any other industrial activity. HSE regulations also require verification of the well design by an independent third party. Once DECC checks the geotechnical information and that the EA / SEPA and HSE are aware of the scope of the well operations, they may consent to drilling. If the well needs more than 96 hours of testing to evaluate its potential to produce hydrocarbons, the operator can apply to DECC for an extended well test of up to 60 days (once all other consents and permissions have been granted) which limits the quantities of gas to be produced and saved or flared. If the operator wishes to drill an appraisal well or propose a development, they start again with the process described above; obtaining the landowner permissions and planning consents, EA or SEPA consultation and HSE notification before DECC would consider approving the appraisal well for development. The minerals planning authority will also consider whether an EIA is required.

The operator should also consult with the EA in England and Wales, or SEPA in Scotland, which are also statutory consultees in the planning process. In Scotland, the Town and Country Planning (Scotland) Act 1997 as amended by the Planning etc. (Scotland) Act 2006 provide for planning provisions, while SEPA is a statutory consultee.

All drilling operations in England, Scotland and Wales are subject to notification to the HSE and each site is assessed by the EA in England and Wales, (and SEPA in Scotland) which regulate discharges to the environment through the environmental permitting regimes. Pursuant to the Environmental Permitting (England and Wales) Regulations 2010 (EPR), an environmental permit may also be required from the EA where fluids containing pollutants are injected into formations that contain groundwater, which could be the case for shale gas exploration and exploitation. An environmental permit may also be needed if the activity poses a risk of mobilising natural substances that could then cause pollution. The permit, if granted, will specify limits on the activity and any requirements for monitoring. While the EA will not issue a permit if the activity poses an unacceptable risk to the environment, a permit may not be necessary if it decides that the activity will not affect groundwater.

The information to be provided in the application for a permit will depend on the type of activity and permit required but may include: the type of facility and activity; the type of discharge and source; how effluent will be treated; monitoring arrangements; the technical ability and financial capacity of the operator; planning status of the installation / activity and a risk assessment. There is no requirement to include any information on specific measures to reduce GHG emissions. The EA may also require further controls where there are discharges into controlled waters under the Water Resources Act 1991, as amended. For example, notification of an intention to drill has to be served on the environmental regulator under Section 199 of the Water Resources Act. In Scotland, the Water Environment (Controlled Activities) (Scotland) Regulations 2011 sets environmental permit requirements for discharges of pollutants into controlled waters. SEPA is the regulating authority responsible for issuing permits. It should be noted that the water legislation does not contain any specific requirements with regard to GHG emissions, for example, possible methane migration into waters.

Other GHG emissions relevant measures in England, Scotland and Wales

It should be noted that under the Energy Act 1976, as amended by the Gas Act 1986, the Secretary of State's consent is required for the disposal of natural gas (whether at source or elsewhere) by flaring or unignited release into the atmosphere.

The Environmental Protection Act 1990, Part III allows for measures to be taken in the event of, *inter alia*, statutory nuisance (i.e. non-regulated activities), noise or odour which may emanate from shale gas exploration.

GHG emissions related considerations in the oil and gas licencing in Northern Ireland

In Northern Ireland, oil and gas licensing is primarily governed by the Petroleum (Production) Act (Northern Ireland) 1964 ('the 1964 Act') and the Petroleum Production Regulations (Northern Ireland) 1987 ('1987 PP Regulations') as amended by the Petroleum Production (Amendment) Regulations (Northern Ireland) 2010 ('2010 PP(A) Regulations'). The 1964 Act vests the rights in petroleum in Northern Ireland in the Department of Enterprise, Trade and Investment (DETI) and enables it to grant licences that confer exclusive rights for the exploration, development, production and abandonment of hydrocarbons in the licence area. In awarding licences, regard must also be given to the Hydrocarbons Licensing Directive Regulations (Northern Ireland) 2010.

As is the case in England, Scotland and Wales, applicants must have the necessary financial and technical capacity and appropriate environmental awareness before a licence will be granted by DETI.

Information to be provided in the Environmental Awareness Statement:

- Understanding of Northern Ireland's environmental legislation which is relevant to the exploration, development and production stages of the project;

- The broad environmental sensitivities of the area applied for and how the applicant would address those sensitivities in operational planning.

DETI assesses the applicant's understanding of environmental issues, including relevant environmental legislation, the broad environmental sensitivities of the area applied for and how the applicant would address those sensitivities in operational planning. As a result of this assessment, DETI will give a 'Pass' or 'Fail' mark for the applicant. It should be noted that this assessment does not specifically take into account GHG emissions.

According to DETI, when granting licences for shale gas operations in Northern Ireland, the environmental impacts of proposed activities on the environment could theoretically be used as criteria to decide between two or more applications of equal merit (and would have merit, particularly where shale gas was the hydrocarbon target). However, DETI noted that such a situation is unlikely to arise in Northern Ireland for the following reasons:

i. Northern Ireland operates an 'open door' or 'first come, first served' policy, rather than a licensing round system for petroleum licensing and competing applications are unlikely to arise because of this.

ii. Petroleum licence applications only specify a work programme for the Initial Term (five years) which corresponds to the exploration phase. Development programmes / plans are only submitted in the Second Term and DETI approval and planning permission (including EIA) are among the pre-requisites for production to take place.

GHG emissions considerations in the planning permissions in Northern Ireland

In Northern Ireland, the EIA process is governed by the Planning (Environmental Impact Assessment) Regulations (Northern Ireland) 2012 (the 'EIA Regulations'). An EIA is compulsory in case of extraction of petroleum and natural gas for commercial purposes where the amount extracted exceeds 500 tonnes per day in the case of petroleum and 500,000 m^3 per day in the case of gas (Schedule 1). Any type of drilling for which the area of the work exceeds 1 hectare, or if it is in a sensitive area (e.g. Area of Special Scientific Interest (ASSI), Area of Outstanding Natural Beauty (AONB), European site etc.) (Schedule 2) is subject to screening to assess whether it requires an EIA. It should be noted that while the EIA process requires certain environmental information, such as climatic factors, to be taken into account there is no specific requirement to include GHG emissions.

Information required in the Environmental Impact Assessment in Northern Ireland:

- A description of the development (including physical characteristics, production processes and an estimate of expected residues and emissions);
- An outline of the main alternatives and an indication of the main reasons for the choice made, taking into account the environmental effects;
- A description of those environmental aspects likely to be significantly affected by the development, including population, flora, fauna, soil, water, air and climatic factors;
- A description of the likely significant effects of the development on the environment, including direct, indirect, temporary and permanent effects.

In relation to the applicable thresholds in Schedule 2 noted above, the DOE has the power under regulation 3(a) of the EIA Regulations to direct that the development described in Schedule 2 which is not in a sensitive area or does not meet the applicable thresholds is still a development requiring an EIA. Therefore given the nature of the hydraulic fracturing process an environmental impact statement may be required regardless of the size or location of the site.

Relevant requirements in the drilling authorisation in Northern Ireland

The petroleum licences require further consents for development work, i.e., for the drilling of any well or development of a field. As part of these consenting processes, DECC expects the applicant to demonstrate that flaring or venting will be kept to the minimum that is technically and economically justified. Specific limits to any flaring or venting will be applied.

At the exploration stage, it is expected that companies exploring for shale gas will seek permission for an "extended well test", which allows production for a sufficient length of time, often 90 days, to establish commerciality. As production facilities would not at that stage be in place the gas has to be flared or vented. DECC confirmed that it will not normally consent to venting unless flaring is not technically possible.

While no field development plans for shale gas have yet been submitted in the UK, DECC would expect all such plans to demonstrate compliance with good production practices that currently apply for conventional hydrocarbon exploitation. However it should be noted that there is currently no BREF (European IPPC Bureau Best Available Techniques Reference Document) for the hydraulic fracturing industry.

Health and Safety of workers

A number of requirements on health and safety of workers are also applicable to shale gas exploration and exploitation.

The UK Health and Safety Executive (HSE) is the regulatory body responsible for regulating the safety of workers from drilling operations, which would include shale gas exploration and exploitation. As regards requirements applicable to health and safety at work, the UK has implemented Directive 92/91/EEC via the following Regulations, which cover both offshore and onshore activities:

Offshore:

- The Offshore Installations (Safety Case) Regulations 1992 and 2005: primary aim is to reduce the risk from major accident hazards to the health and safety of the workforce employed on offshore installations or in connected activities. They required every operator, or owner, of an offshore installation to prepare a safety and health document (safety case) and submit it to HSE for acceptance. This will cover the principles of risk prevention, the assessment of risks and the preventative and protective measures selected. Operators are also required to set up a verification scheme and seek input from an independent competent person;
- The Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995: these set out requirements for the safe management of offshore installations, such as the appointment of installation managers, the use of permit-to-work systems and health surveillance;
- The Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995: these provide for the protection of people from fire and explosion, and for securing effective emergency response. They require the necessary assessment of risks and the introduction of appropriate control measures to address these risks;
- Offshore Installations and Pipeline Works (First-aid) Regulations 1989: These Regulations outline the offshore first aid and basic health care provision requirements;
- Offshore Installations (Safety Representatives and safety Committees) Regulations 1989: These regulations cover requirements related to consulting and informing workforce representatives and on the responsibilities and powers of safety representatives.

Onshore:

- The Borehole Sites and Operations Regulations 1995 and the Borehole Sites and Operations Regulations (Northern Ireland) 1995 (BSOR Regulations): As shale gas operations are concerned with the extraction of "petroleum" (oil and gas), Regulation 6(1) requires the Borehole Site Operator to notify HSE of these operations a minimum of 21 days before they can commence. The Borehole Site Operator must supply the information as detailed in Schedule 1, Part 1. The Regulations also require the operator to ensure, inter alia, that workplaces on a borehole site are designed and built to a certain standard (Regulation 8). Furthermore, they prohibit commencement of a borehole operation unless the operator ensures that a health and safety document has been prepared, specifies the matters which the document must contain, requires that the operator ensures that it be kept up to date, and requires employers to have regard to it (Regulation 7). The health and safety document must contain specific information including: a demonstration that the risks to which persons at the borehole site are exposed whilst they are at work have been assessed, an escape plan for employees, a plan for the prevention of fire and explosions and any uncontrolled escape of flammable gases and for detecting the presence of flammable atmospheres and a fire protection plan.

An assigned OSD Wells Inspector will inspect the notification to ensure that it complies with, among other regulations, the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 (DCR) and industry good practice. If the inspector has any concerns or requires further information they will contact the Borehole Site Operator as part of the inspection process. No consent is given to commence operations by HSE and the Borehole Site Operator can start operations after the 21 day period has elapsed. HSE would have to serve a prohibition notice to stop operations. The DECC as issuer of the licence do run a consents scheme.

Regulation 9(1) also requires the Borehole Operator to ensure suitable well control equipment such as blow out preventers are provided and deployed on the well when the conditions require it;

- The Health and Safety at Work etc Act 1974 also applies to shale gas operations, as do more specific regulations focused on general occupational health and safety, borehole operations and well integrity.

Onshore and offshore:

- The Offshore Installation and Wells (Design & Construction etc.) Regulations 1996 and the Offshore Installation and Wells (Design & Construction etc.) Regulations (Northern Ireland) 1996 are applicable to all wells drilled with a view to the extraction of petroleum regardless of whether they are onshore or offshore. These regulations are primarily concerned with well integrity and there are no specific obligations with regard to fugitive methane or GHG emissions. Regulation 13 places a general duty on the well-operator to ensure that the well is designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned, that so far as is reasonably practicable, there can be no unplanned escape of fluids (which could be interpreted as including methane – the regulation is not specific about this) from the well and risks to the health and safety of persons from the well, including anything from within the well or from the strata to which the well is connected, so far as is considered as low as is reasonably practicable (ALARP). Regulation 14 requires the well operator to assess the conditions below ground through which the well will pass during the design phase of the well and while the well is being drilled. Regulation 18 requires the well operator to set up a well examination scheme and appoint a well examiner. The Well Examination Scheme and involvement of the well examiner is for the complete lifecycle of the well from design through to abandonment. The well examiner is an independent competent person who reviews the proposed and actual well operations to confirm they meet the well operators policies and procedures, comply with the Regulations and follow good industry practice. Regulation 19 requires the well operator to submit a weekly report to HSE on the past weeks operations on the well. This enables the wells inspector to monitor progress on the well and determine if the well operator is conducting their operations as per the well notification submitted to HSE. Regulation 21 requires the well operator to ensure that all persons working on the well are suitably informed, instructed, trained and supervised so that the risks to them are as low as is reasonably practicable;
- Reporting of Injuries Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR): Regulation 3 of The Reporting of Injuries Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR) has a specific set of Wells Dangerous Occurrences contained in Schedule 2, Part I that the Well Operator has to report to HSE. These include a blowout i.e. an uncontrolled flow of well fluids; the unplanned use of blow out prevention equipment; the unexpected detection of H2S; the failure to maintain minimum separation distance between wells; mechanical failure of any safety critical element of a well;
- The Control of Major Accident Hazards Regulations 1999 (as amended), and the Control of Major Accident Hazards Regulations (Northern Ireland) 2000 (as amended) impose requirements with regard to the control of major accident hazards involving dangerous substances. These Regulations are made under the Health and Safety at Work Act 1974 and implement EC Directive 2003/105/EC amending Directive 96/82/EC. It should be noted however that according to DECC, conventional onshore fields to which the Regulations apply are unlikely to store hydrocarbon products in sufficiently large volumes so as to warrant

control under the COMAH Regulations. Furthermore, there is nothing in these regulations which deals specifically with GHG emissions such as methane.

The health and safety framework in the UK does not require environmental risks associated with drilling to be assessed, but it is assumed by UK regulators that the very high well integrity standards required to protect lives and the safety of workers will in practice ensure that most environmental risks from well integrity are also addressed.

General requirements applicable to well completion and GHG emission limits – England, Scotland and Wales

There are no general emission control regimes over GHG gases as such. However, according to the DECC, in addition to those provisions noted above, a number of regulatory regimes will have the effect of restricting or controlling methane emissions from oil and gas activities including shale gas, as follows:

- Environmental Permitting;

According to The EA it is considering the implications of the European Commission's interpretation on the applicability of the Industrial Emissions Directive and the Mining Waste Directives in determining its regulatory stance. It has started a full review of the regulations and controls it may require to ensure effective regulation of shale gas.

- Health and Safety of Workers;

The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 (DCR) also include goal setting requirements which place the responsibility on those who create risks to demonstrate that they have adequately assessed the risks associated with their work activities and put in place appropriate measures to control these. These Regulations have the flexibility to require operators to consider new standards or best practice as they emerge and to drive them to continually improve.

6.3.1.3 *Institutional framework*

As noted above, there are a number of different authorities in the UK responsible for overseeing shale gas activities, each of which will enforce its own legislation and, where appropriate, place reporting requirements on operators. The main authorities are as follows:

The Department of Energy and Climate Change (DECC): is the UK government department responsible for licensing, exploration and regulation of oil and gas developments on the UK continental shelf. In Northern Ireland, the Department of Enterprise, Trade and Investment (DETI) is responsible for issuing licences.

The Environment Agency (EA): is the environmental regulator responsible for advising government and regulating discharges to the environment in England and Wales. In Scotland this function is carried out by the Scottish Environmental Protection Agency (SEPA), in Northern Ireland the Department of the Environment (DOE) and the Northern Ireland Environment Agency (NIEA).

The Health and Safety Executive (HSE): is the UK non-departmental public body responsible for regulating the process safety risks (including workplace health and safety) of shale gas activities, and contributing to the mitigation of environmental risks. In particular, the HSE is responsible for ensuring the appropriate design and construction of a well casing for any unconventional gas borehole. It is the operator's responsibility to assess the risks and ensure that appropriate controls are put in place. In the UK risks to health and safety, including those associated with shale gas operations, operators must take appropriate action to reduce the risks to as low as is reasonably practicable. For health and safety, HSE as the regulatory agency will oversee this process and take enforcement action when necessary. The HSE regulates shale gas wells using the same regulations (e.g. DCR) and standards as are applied to other onshore oil and gas wells.

Enforcement

In terms of enforcement, both HSE and the EA have to be consulted and / or notified before any drilling operations take place, and have powers to halt operations if they have concerns. HSE is the enforcing authority for the health and safety aspects of shale gas operations and the EA regulates environmental aspects. HSE, EA and DECC work closely together to share relevant information on such activities, ensure that there are no material gaps and that all material concerns are addressed.

In Northern Ireland, these functions are primarily carried out by the DETI, DOE (and its agency the NIEA).

Reporting

According to UK authorities, only one well has been hydraulically fractured to date and that required no environmental permit. There was no potable aquifer present and the flow back was tankered away to a licensed waste water treatment facility. Since October 2011 the flow back has been stored pending disposal to a site which is suitable to take it on account of its naturally occurring radioactive material content. This disposal requires permitting. For future operations, should a permit be required, then the EA will require monitoring by the operator of environmental aspects appropriate to the permitted activity. The EA is reviewing its regulatory approach, as mentioned above.

The British Geological Survey is conducting a survey of baseline methane concentrations in groundwater. For this they have approached the EA for borehole access and any past records. The purpose is to set a baseline of measurement across areas of the country where shale gas may be present in exploitable quantities to facilitate comparisons after any hydraulic fracturing.

For the health and safety aspects of shale gas operations HSE wells group inspectors inspect well notifications submitted to HSE as per the requirements of BSOR Regulation 6(1). All well notifications are inspected upon submission. This inspection process is conducted in the design phase of the well where the vast majority of issues likely to have an impact on well integrity will be identified and addressed by the well operator.

Monitoring of the well operations is conducted by the wells group inspectors, inspecting all the weekly operations reports submitted to HSE as per the requirements of DCR Regulation 19.

As part of the well notification process inspection meetings may be held with the well operator both at their office and at HSE offices. Further meetings may be held as required. On-site inspections may be conducted at the borehole site.

General conclusions on current legal requirements – UK

In the UK, shale gas activities are covered by the general provisions for conventional oil and gas exploration and development and there are no general control regimes which deal specifically with GHG emissions and methane flow back. A number of regulatory regimes in the UK have the indirect effect of restricting or controlling methane emissions from oil and gas activities including shale gas. These include the regimes relating to petroleum licensing, environmental permitting and health and safety. Licenses for shale gas exploration and exploitation are issued by the relevant authority (either DECC or DETI), who must be satisfied with the technical competence and environmental awareness of its proposed operator, but GHG emissions are not specifically taken into account. Furthermore, where a shale gas development falls within the scope of EIA, applicants may be required to supply information, including a description of estimated emissions and environmental impacts (such as air and climatic factors) as part of an environmental statement. However, there is no specific requirement to include information on GHG emissions in this statement.

In light of the early stage of development of shale gas activities in the UK, the authorities confirmed that the regulatory position for some aspects of on-shore unconventional gas is currently under review. In Northern Ireland consideration is currently being given by DOE to the existing regulatory regimes which could be used, either in their current form or amended, to control emissions to air from shale gas production and to establish whether these need to be supplemented. DOE is working with its counterparts in the rest of the UK in a similar review, although neither has yet progressed sufficiently to have reached any conclusions. In anticipation of any future application for hydraulic fracturing, NIEA have drafted an environmental regulatory framework that would apply. However, they indicated that the specific suite of regulations that will apply will be on a case by case basis specific to each individual operations proposed working practices and location.

6.3.2 Case Study: Legal requirements on the climate change impact of shale gas exploitation: FRANCE

6.3.2.1 *Background information*

Since 2004, the French government has granted nine permits for the exploration of shale oil and gas. To date none of the companies have carried out drillings of the French geological shale formations. As a result of a strong public campaign around the potential environment and health impacts of the exploitation of shale gas a law was passed in July 2011 banning the exploration and exploitation of shale gas and oil using hydraulic fracturing technology (see further details below) and abrogating three exploration permits to Schuepbach, Total and Devon using this process.

6.3.2.2 *Legal framework for the exploration and exploitation of shale gas in France*

General principles

Article 1 of the Law 2005-781 of 13 July 2005 setting the strategy of the French energy policy provides that this policy must contribute to the national energy independency, guarantee the energy security and the social and territorial cohesion by ensuring access to energy for all and to preserve human health and the environment, particularly through the fight against GHG emissions. Article 2 of this law stipulates that the State must, amongst other actions, promote the reduction of GHGs and pollutants during energy extraction and production.

Mining legal regime

The exploration and exploitation of shale gas is regulated by the Mining Code. Article L-111-1 states that underground mineral deposits such as gaseous hydrocarbons, which includes shale gas, must fall under the general mining legal regime. The Mining Code sets two types of authorisation procedures. The first one involves the award of mining rights (titres miniers) for the exploration stage (permis exclusifs) and the exploitation stage (concession) and the second decides on the opening of the exploration or exploitation activities (ouverture des travaux). It should be noted that the legislative part of the Mining Code has been very recently subject to a full revision.

GHG emissions related considerations in the award of mining rights

Mining rights for the exploration stage are granted for a maximum period of five years and can be renewed twice. The award of mining rights for the exploration stage is carried out through a public tender procedure, where applicants must, among other information, provide an environmental impact assessment indicating the potential impacts of mining works on the environment and the measures taken to mitigate this impact. This is a general requirement that does not specifically address GHG emissions.

Mining rights for the exploitation stage are granted for a maximum period of 50 years and must be renewed every 25 years in this time period. The award of mining rights for the exploitation stage is also done through a public tender procedure where applicants must provide an environmental impact assessment indicating the potential impacts of mining works on the environment and the measures taken to mitigate this impact. In addition, the environmental impact is subject to public consultation in which observations and comments can be provided to the Prefect (the State representative in the regions).

GHG emissions related considerations in the permit procedure for shale gas exploration and exploitation mining works

Decree 2011-2019 entered into force on 1st June 2012, reforming the environmental impact assessment legislation such that the start of drilling works for mining exploration and exploitation of more than 100 metres depth (which include shale gas exploration and exploitation drilling works) has to be subject to an environmental impact assessment and a risk study[30]. Furthermore, the permit application for these mining works is subject to a public enquiry where the public and stakeholders are consulted[31]. This involves public consultation concerning the environmental impact assessment and of the risk study proposed by the permit applicants.

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[30]Before first June 2012 the start of mining works for shale gas exploration activities was subject to the declaration procedure as mentioned under Article L.162-10 of the Mining Code read in conjunction with Article 8 of the Decree 2006-649 as modified. Pursuant to these provisions applicants did not have to provide an exhaustive environmental impact assessment but had only to include in their declaration a note indicating the potential impact on the environment of the mining works and how the activity will meet the environmental concerns and a document on the impact of mining works on water resources and if relevant its compatibility with the river basin management plans. As of first of June 2012 both the grant of a permit for the start of the exploration and exploitation mining works are subject to an environmental impact assessment.

[31] Before first of June 2012 the permit application for the opening of exploration mining works was not subject to a public enquiry. The new public enquiry requirements are encompassed in Decree 2011-2018 reforming the public enquiry for projects with a potential impact on the environment *(Décret n° 2011-2018 du 29 décembre 2011 portant réforme de l'enquête publique relative aux opérations susceptibles d'affecter l'environnement)*.

Information to be provided in the environmental impact assessment (Article R122-4 of the Environmental Code) as of first of June 2012:

- Information on the design and dimensions of the project including a description of the physical characteristics of the whole project and the technical land-use requirements during the construction and operational phases;
- Where relevant a description of the main characteristics of the processes of storage, production and manufacturing, including the ones implemented during the operation phase, such as the nature and quantity of materials used and an estimate of types and amounts of expected residues and emissions resulting from the operation of the proposed project;
- An analysis of the initial state of the environment likely to be affected by the project, including population, wildlife, natural habitats, material assets, sites and landscape, the ecological continuity, ecological balance, climatic factors, cultural and archaeological heritage, soil, water, air, noise, the natural, agricultural, forestry, marine and leisure areas, as well as the interrelationships between these elements;
- An analysis of negative and positive, direct and indirect, temporary (including during the construction phase) and permanent, short, medium and long term impacts of the project on the environment, and on energy consumption, the convenience of the neighbourhood (noise, vibration, odor, light emissions), hygiene, safety, public health, as well as the addition and the interaction of these impacts;
- An analysis of the cumulative effects of the project with other known projects;
- An outline of the main alternatives studied by the applicant and the reasons why, given the effects on the environment or human health, the proposed project was selected;
- The information needed to assess the project's compatibility with land use requirements;
- The measures provided by the applicant:
  - to avoid the significant adverse effects on the environment or human health and reduce the effects that cannot be avoided;
  - to compensate, where possible, the project's significant adverse effects on the environment or human health that could not be avoided or not sufficiently reduced. If it is not possible to compensate these effects, the applicant must justify why.
- The description of these measures must be accompanied by the corresponding expenditure estimates, the presentation of the expected effects of these measures with respect to project impacts and how they will be monitored;
- An overview of methods used to assess the initial state of the environment and evaluate the project's effects on the environment and, when several methods are available, an explanation of the reasons that led to the choice made;
- A description of any technical or scientific difficulties, encountered by the applicant for this study.

Information to be provided in the risk study *(Article L-512-1 of the Environmental Code)*

- Information on the risks and hazards for the convenience of the neighbourhood, or for public health and safety, or for agriculture, or for the protection of nature and the environment, or for the conservation of sites and monuments or elements of the archaeological heritage, in case of accidents, which cause is internal or external to the activity;
- Where needs be a risk analysis which takes into consideration the probability of an accident occurring and the kinetics and gravity of potential accidents, in accordance with a methodology which is explained in the said analysis;
- Appropriate measures to reduce the probability and effects of such accidents.

The EIA procedure under French legislation requires certain environmental information, such as climatic factors to be taken into account, but there is no specific requirement to include information on GHG emissions.

Furthermore authorisations of shale gas activities, provided that there is no use of the hydraulic fracturing technique (see section below on the law 2011-835), can be granted subject to the application of specific conditions such as, among others, the control by the operator of the impact of the activity on water and the environment[32].

Reporting on mining works

Pursuant to Article 37 of the Decree 2006-649 the holder of liquid or gaseous hydrocarbon exploitation rights (including shale gas exploitation) must submit to the Prefect an annual programme of the future mining works to be carried out in the calendar year, together with a study on the final recovery of the products contained in the deposit. This document must include all the necessary information to assess the technical and economic conditions for the exploitation. The Prefect can order supplementary works if necessary. There is no specific mention of requirements in relation to environmental impacts or GHG emissions.

The law 2011-835 of 13 July 2011

Following a very active public campaign from civil society and environmental associations the law 2011-835 of 13 July 2011 was passed to prohibit the exploration and exploitation of oil and shale gas using hydraulic fracturing technology. This prohibition is based on the application of the principle of preventive and corrective action encompassed in Article L-110-1 of the Environmental Code.

This law also established a national commission[33] responsible for assessing the environmental risks due to hydraulic fracturing and alternative techniques. This Commission is entitled to issue public opinions and to propose to the Ministries with responsibility for mining, industry, energy, ecology and sustainable development actions to assess any questions related to the exploration and exploitation of shale oil and gas. The commission can also be consulted by these Ministries on:

- The implementation of pilot projects using hydraulic fracturing technology or any alternative technologies;
- Any proposed regulation to reduce the environmental impacts and risks for the test of new technologies;
- Any research programme or study on the impact of hydraulic fracturing technologies or alternative technologies, notably concerning climate change impacts of the potential exploitation of shale gas[34].

Article 2 of 2011-835 stipulates that within a timeframe of 2 months from its promulgation, the holders of mining rights for shale gas explorations were required to submit to the relevant administrative authority a report specifying the technology used or envisaged for their exploration and research activities. These reports were made available to the public. Mining rights were to be withdrawn if the reports were not submitted or if it mentions that hydraulic fracturing technology is used or planned to be used. As a consequence of these provisions three exploration mining rights were withdrawn by an Order of 12 October 2011.

Requirements for Health and safety of workers under the Decree 80-331

The Decree 80-331 regulating extractive industries applies to all drillings from the surface of the earth or executed at sea, to extract substances covered by Article L-111-1 of the Mining Code, which include shale oil and gas. This Decree sets specific health and safety requirements to protect workers from the hazards and risks inherent to this activity under a Title called 'exploration by drilling, exploitation of fluids by wells and treatment of these fluids'. This title transposes Directive 92/91/EEC concerning the minimum requirements for improving the safety and health protection of workers in the mineral extracting industries through drilling. It sets general requirements that apply to all drillings, such as the employer obligation to produce a security and health document, to set a monitoring programme of the installations, measures against the corrosion of the canalizations and machines, on

[32]See Article 15 of Decree 2006-649 2 of June 2006 related to mining works, underground storage works and of the mining police and underground storage *(Décret n°2006-649 du 2 juin 2006 relatif aux travaux miniers, aux travaux de stockage souterrain et à la police des mines et des stockages souterrains).*

[33]This Commission is composed of members of the Parliaments, State representatives, representatives of communities and local administrations, NGOS, associations of employers and workers concerned.

[34]See Decree 2012-385 of 21 March 2012 relating to the national commission on the monitoring and assessment of exploration and exploitation technics for shale oil and gas *(Décret n° 2012-385 du 21 mars 2012 relatif à la Commission nationale d'orientation, de suivi et d'évaluation des techniques d'exploration et d'exploitation des hydrocarbures liquides et gazeux)*

lightning, emergency routes and exits, equipment to use in rescue and emergency situations or the obligation to regularly carry out security exercises at the workplace.

It also provides for more specific health and safety requirements in cases of exploitation of gaseous and liquid fluids that are flammable, under pressure or likely to release toxic gases. These characteristics would apply for the exploitation of shale gas. The requirements are summarized below.

Summary of the OHS provisions on the exploitation of gaseous and liquid fluids, flammable or under pressure or likely to release toxic gases under the Decree 80-331 regulating extractive industries (see Title F0-1P-2-R).

- **Protection against explosion and noxious atmosphere;**
  (health and safety documents must take into account the risk of accidental eruptions and flows, measures to prevent the occurrence and accumulation of explosive atmospheres, monitoring of the concentration of gas in the atmosphere).

- **Measures to secure wells;**
  (specific measures to secure flowing wells and sleeping wells).

- **Measures to limit the risk of fire;**
  (prohibition to store easily flammable or explosive products in the exploitation zone except for the fuel for the engines).

- **Specific measures during drilling works and significant interventions inside wells;**
  (specific training for workers, security exercise, preventive and protection measures against explosions, fire and noxious atmosphere, measures during the leak-off test or formation integrity test, monitoring of potential surge or flow of hydrocarbons, measures for flared gas equipment and to control kicks and prevent blow-out).

6.3.2.3 *Institutional framework*

At the State level, three authorities have responsibility for the exploration and exploitation of shale gas.

The Legislation Office on Mine and Raw Material

This office has responsibility for the regulation and legislation on mines under the General Directorate on planning, housing and nature of the Ministry of Ecology, Sustainable Development, Transport and Housing (Ministry of Sustainable Development).

The Office of Soil and Underground

This office is part of the General Directorate on the prevention of risks of the Ministry of Sustainable Development. This Office has responsibility for mining inspection (police des mines) and of the enforcement of the Regulation on mining extractive industries.

The Office of Exploration and Production of Hydrocarbons

This Office is part of the General Directorate of Energy and Climate. It has responsibility for the elaboration of the policy on the exploration and production of hydrocarbons and the award of hydrocarbon mining rights.

At the Regional level, mining inspection is under the control of Prefects with the support of the Regional Directions on the Environment, Planning and Housing. The enforcement powers for mining inspection concerning the exploration and exploitation of hydrocarbons are regulated under Articles 30 to 34 of the Decree 2006-649.

General conclusions on current legal requirements – France

With the entry into force of the law 2011-835 of 13 July 2011 the exploration and exploitation of oil and shale gas using hydraulic fracturing technology is prohibited in France, mainly because of the potential impact on groundwater. The GHG emissions from shale gas activities were not the main concern of the French legislator. Indeed the French legislation on mining activities that would apply to shale gas exploration and exploitation does not set specific requirements for methane flow back and resulting GHG emissions.

6.3.3 Case Study: Legal requirements on the climate change impact of shale gas: POLAND

6.3.3.1 *Background information*

On March 20 2012 the Polish Geological Institute released a report on shale gas potential in Poland. The methodology was based on U.S. GS practice and data was gathered from archives of PGI (historic drills of 1950-1990). According to this report there may be up to 2 trillion m^3 (1,920 billion m^3) of recoverable shale gas reserves, although it is more likely to be in the range 346 to 768 billion m^3. This is as much as 5.3 times more than the conventional deposits documented to date (which in Poland are of the size of circa 145 billion m^3). With the current annual demand for natural gas in Poland (ca. 14.5 billion m^3), this is enough to satisfy the demand for natural gas of the Polish market for almost 65 years. According to our discussions with the Polish authorities this is also equivalent to up to 200 years of natural gas production in Poland at the current level (without changing the level and ratios of supply from imported and national sources). The Ministry of the Environment expects that the amount of gas prospected in the Polish Geological Institute report will be adjusted after collecting new drilling data from works being currently executed.[35]

Poland is very dependent on Russian's carriers and has experienced problems of energy supply in the past. Therefore the development of shale gas is considered by the Polish authorities as a key component of its strategy to diversify its energy mix and to improve its energy security. Shale gas deposits are located in a zone stretching from the north-west to the south-east of Poland with authorisations for exploration already granted in most of this zone. In the EU, Poland has until the date of publication granted the highest number of authorisations with around 50 drillings foreseen in 2012. According to the work schedule, by the end of 2017, the Concession's holders are obliged to drill 121 exploration wells (with options to drill another 127).

6.3.3.2 *Legal framework for the exploration and exploitation of shale gas*

General legal regime

The exploration and exploitation of shale gas in Poland is mainly regulated by the new Geological and Mining Law of 9 June 2011 (GML). Pursuant to this law companies that were dualy registered in compliance with the Freedom of Economic Activity Act may apply for an exploration or production concession (koncesja) issued by the Ministry of the Environment, to prospect, explore or exploit hydrocarbons including shale gas. Concessions are granted for three to fifty years. In addition to the grant of a concession, since deposits of hydrocarbons are the property of the State Treasury, companies must conclude a mining usufruct agreement with the State Treasury which gives them the right to undertake exploration and production activities in these deposits. In cases like: geological works and the use of explosives; performance of activity by underground method; performance of activity by drilling holes with the depth more than 1000 m or when a concession concerns a sea territory of Poland, the decision on the environmental conditions is required as part of the application for concession. The start of shale gas mining works is subject to approval by the regional mining authorities of a mining work program proposed by companies. Finally the mining plant operations must proceed on the basis of an operation plan to be approved by the competent mining supervision authority.

The Act of 3 October 2008 on the Provision of Information on the Environment and its Protection, Public Participation in Environmental Protection and Environmental Impact Assessments transposes Directive 85/337/EC. Following the same approach of the Directive, this law sets two legal regimes for projects based on their potential environmental impacts. For projects in Annex I an environmental impact assessment is compulsory. Shale gas explorations outside Annex I that fulfil certain criteria (see table below) are considered 'Annex II' projects. These require an environmental impact assessment only if, after a mandatory examination it is demonstrated that the exploration activities have a significant impact on the environment. The circumstances where there is a need for a full EIA in relation to shale gas explorations, following this screening, are described below The application for concessions must contain a decision on environmental conditions at the site. The decision on environmental conditions is granted after the EIA procedure.

[35]Information provided by the Polish authorities during the interview procedure.

Information required in the environment impact assessment:

- description of the project comprising information on the site, design and size of the project;
- description of the measure envisaged in order to avoid, reduce, and, if possible, remedy significant adverse effects;
- the data required to identify and assess the main effects which the project is likely to have on the environment;
- an outline of the main alternatives studied by the developer and an indication of the main reasons for his choice; and
- A non-technical summary of the information listed above.

Shale gas explorations are subject to a mandatory screening that must conclude whether there is a need or not for a full EIA in case it involves:

- geological works and the use of explosives;
- performance of activity by underground method;
- performance of activity by drilling holes with the depth more than 1000 m;
- operation in the sea territory of Poland.

Shale gas exploitation is subject to an environmental impact assessment where:

- Exploitation of the deposits of the natural gas is more than 500 000 m^3 per day;
- An exploitation takes place in the marine areas of Poland.

GHG emissions related conditions decision and the award of exploration and exploitation concessions

GML sets out the conditions for undertaking and terminating activities in the field of geological development works and extraction of minerals from deposits. Special regulations have been applied to the issues of prospecting and exploration of hydrocarbon deposits and extraction of hydrocarbons from deposits.

GML sets out conditions to be fulfilled by applicants to be entitled to participate to the tender procedure, which among others, are:

- conditions for environmental protection, and the rational use of mineral deposits;
- requirements necessary to ensure public security;
- the conditions of the security claims when needed for its establishment; and
- the award of a decision on the environmental conditions.

Therefore the award of concessions for the exploration and exploitation through a public tender procedure is likely to be subject to the decision on environmental conditions issued by competent authorities (local authority with the consent of Regional Director for Environmental Protection or Regional Director for Environmental Protection that details for each specific site the environmental requirements that must be followed by companies, see below)[36].

Requirements to be detailed in the decision on environmental conditions:

In a decision on the environmental conditions the competent authority must define:

a) the type and place of the implementation of the project;
b) the conditions for the use of the area at the stages of the implementation and operation or use of the project, with particular consideration given to the need to protect special natural values, natural resources and cultural heritage sites and to reduce the annoyances for the adjacent

[36] See the Act of 3 October 2008 on making the environmental information available and environment protection, participation of the society in environment protection and on the assessment

areas;

c) the requirements of environmental protection which must be taken into account in the documentation required for the issue of the decision;
d) the requirements to prevent the effects of industrial accidents, in the case of projects classified as plants which represent major-accident hazards;
e) the requirements to reduce the transboundary impact on the environment in the case of projects for which the procedure for the transboundary impact on the environment has been carried out.

The competent authority must also impose the operator:

a) to compensate the effect on the environment and to state the need to perform such compensation;
b) to prevent, reduce and monitor the environmental impact of a project – impose the obligation to carry out these actions;
c) in particular cases referred in other legal acts state the need to establish a restricted use area;
d) may impose on the applicant the requirement to present a follow-up analysis, setting out its scope and the date of its presentation.

Over all the Polish legislation (EIA and environmental decision requirement) does not set specific requirements or conditions with regard to GHG emissions of shale gas exploration and exploitation.

The geological work programme

Pursuant to the Geological and Mining Law of 9 June 2011, the start of hydrocarbon prospecting and exploration works, including shale gas, must be subject to a geological work programme approved by the relevant administrative authorities.

Information to be provided in the geological work programme inter alia:

a) The objective of the works planned and the way of achieving that objective, together with the specification of the type of geological documentation required;
b) The works schedule;
c) The space within the boundaries of which the geological works are to be carried out;
d) Undertakings necessary for the protection of the environment, including particularly groundwater protection and the manner of closing down excavations and boreholes as wells as land reclamation and measures to prevent damage.

Under the geological work programme, measures to protect the environment must be provided but they do not refer to GHG emissions (the focus is on groundwater protection).

The mining plant operation plans

Pursuant to the Geological and Mining Law of 9 June 2011, mining plants operations plans prepared by operators must be approved by the relevant national authorities.

Mining plants operations plan must specify detailed measures necessary to secure inter alia:

a) General safety;
b) Fire safety;
c) Work safety and health for employees of the mining plant;
d) Correct and efficient management of the deposit;
e) Protection of the environment and of building facilities;
f) Prevention of damage and its remedy.

The mining plant operation plans oblige operators to specify detailed measures to protect the environment but it does not contain any specific requirements with regard to GHG emissions.

Detailed requirements set by Ministerial Ordinance

According to the GML the minister responsible for the economy shall specify by way of an Ordinance, in consultation with the ministers responsible for labour affairs, internal affairs and environment affairs, the detailed requirements related to inter alia:

- work health and safety, assessment and documentation of professional risks;
- fire protection;
- management of mineral deposits during the extraction;
- environment protection;
- preparation of the extracted deposits for sale;
- facilities, machinery and equipment of the mining plant associated with operations of particular types of deposit, and;
- cases in which the entrepreneur must have proof of the verification of technical solutions by the expert of mining plant operations.

General requirements applicable to well completion and air emissions

For each well of hydrocarbon prospecting and exploration, plans are prepared for the geological works and operation. These documents determine the construction of the well and requirements for well drilling, taking into account the minimization of the work's negative impact on the environment as well as issues concerning processes from the preparation of the well to the extraction of gas (production) and its liquidation (closure).

The operation plan is authorized by way of a decision by the appropriate mining supervision authority. The operator presenting the operation plan for authorization must also enclose decisions (permissions) concerning the impact on the environment, including those on waste management and air emissions. The conditions of those decisions (permits) should be reflected in the content of the operation plan.

Independent of the rules set in the documents for the project concerning geological works and operational plans, the ordinance of the Ministry of Economy requires operators of projects (approved by the manager of the plant) to determine detailed technical and technological issues related to drillings, processes and exploitation of a deposit. In those drafts the minimization of the negative impact on the environment is required, particularly the minimization of air emissions including gases described in the environmental decisions i.e. through keeping relevant technical condition of heads and technological tools. This requirement applies to air emissions from wells in general and would indirectly cover methane emissions from shale gas exploration and exploitation.

Requirements on Health and safety of workers

Requirements on safety and hygiene at work related to mining works and drilling of deposits (production) are determined by the Ordinance of the Ministry of Economy of 28 June 2002 on safety and health at work, performance of the operation and specialized fire-protection in plants extracting deposits by wells. The provisions on such issues are also included in the draft Ordinance of the Ministry of Economy on detail requirements concerning operation of plants extracting deposits by wells.

In those regulations thresholds are set for concentrations of methane in the atmosphere (rooms) in the plant as well as rules of hazard prevention and monitoring. The general principles are to maintain sealing of gas installations and to set hazard zones for installations which could be gas emitters. The prevention concerns the application of installations with special construction criteria (for example to be explosion proof) and monitoring in the areas of potential hazard occurrence.

The responsible body for issues such as supervision of geological and mining operations and supervision of work and health safety are the State Mining Authority / Regional Mining Authorities.

Requirement on methane emissions

In Poland a permit for emitting gases to the air (including methane) is required for 10 years. Apart from this general requirement the Polish legislation does not specifically address methane emissions from shale gas exploration and exploitation.

6.3.3.3 *Institutional framework*

There is more than one authority in Poland involved in preparing and supervising shale gas activities including:

- Ministry of the Environment *(grants concessions and supervision of concessions);*
- General Directorate for Environmental Protection / Regional Directorates for Environmental Protection *(supervision of environmental decisions procedures, management of Natura 2000 sites, impacts of projects on Natura 2000 sites);*
- Chief Inspectorate of Environmental Protection and regional inspectorates *(permits compliance check and environmental monitoring);*
- State Mining Authority / Regional Mining Authorities *(supervision of geological and mining operations, supervision of work and health safety);*
- Relevant regional and local competent authorities (according to the legal provisions) – (*responsibility for implementing legal provisions; granting different kind of environmental permits).*

The mining supervision organisations responsible for surveillance of the operation of mining plants (mining companies) and plants performing geological works (operators) also control the fulfilment of the rules prescribed in the above mentioned legal regulations. The Act on Geological and Mining Law determines sanctions in case of the infringement of law.

There are two stages of monitoring for projects that may have significant impact on the environment and were subject to an EIA procedure. The Regional Inspectorates for Environmental Protection have to be notified about the start of the project 30 days ahead and control the site before the operations begin. It is also authorized to monitor the site during the operations. The operator should submit documentation of works and all necessary permits, as well as enable the site for inspection and sampling.

The Ministry of the Environment, as an organisation responsible for granting concessions, monitors if geological works done by the entities are made according to the granted concession. Concession holders send information about quantity and the stage of geological works mentioned in the concession. In case of failure with the concession, the concession can be withdrawn.

General conclusions on current legal requirements – Poland

Poland does not apply any specific requirements to control or reduce GHG emissions from shale gas exploitation and exploration. Both the mining legislation and the EIA legislation refer to measures to protect the environment in general, or require general information on the environmental impact of these activities, or on air emissions. There are no specific requirements in the Polish legislation that focuses on the emission of GHG from shale gas explorations and exploitations.

6.3.4 Conclusions from case studies

This section presents General findings from the country studies on the legal requirements on the climate change impacts of shale gas exploration and exploitation in France, Poland and UK. On the basis of desk-research and questionnaires to competent authorities, the following general conclusions can be drawn.

- Reliance on general mining legislation and relevant EU requirements:

Poland, France and the UK rely on their existing mining legislation on hydrocarbons and on the current EU requirements transposed in their legal order (e.g. EIA Directive) to control the GHG emissions of shale gas exploration and exploitation. None of these countries have set specific legal requirements to control and reduce GHG emissions from shale gas activities.

France has until now taken the most stringent approach since it prohibits the exploration and exploitation of shale gas using hydraulic fracturing, mainly because of its potential impact on water resources. The French authorities mention that this technology is also responsible for the methane flow-back during exploration and exploitation.

None of the countries assessed clearly mention that shale gas exploration and exploitation must be automatically subject to an Environmental Impact Assessment. The requirements for EIA are shown in the table below. In the UK (after a screening procedure) and France it is most likely that an EIA would be required for shale gas drilling under the current criteria since these types of drillings are usually more than 100 metres depth and the area of works should exceed 1 hectare.[37] In Poland the criteria are less stringent since the screening to decide whether an EIA is required is compulsory for drillings of more than 1000 metres depth[38].

Table 26: EIA relevant for shale gas exploration and exploitation

EIA requirements relevant for shale gas exploration and exploitation			
France	UK	Poland	EIA Directive
Drilling works for mining exploration and exploitation of more than 100 metres depth is subject to a compulsory EIA. Opening of exploitation mining works for the extraction of liquid or gaseous hydrocarbons is subject to a compulsory EIA.	Drillings the area of the work exceeds 1 hectare is subject to screening to assess whether the project requires an EIA or not. Extraction of petroleum and natural gas for commercial purposes, where the amount extracted exceeds 500 tonnes per day in the case of petroleum and 500,000 m^3 per day in the case of gas is subject to a compulsory EIA.	Exploration stage: geological works and the use of explosives, performance of activity by underground method; performance of activity by drilling holes with the depth more than 1000 m, operation in the sea territory of Poland are subject to screening to assess whether they require an EIA or not. Exploitation stage: Where exploitation of the deposits of the natural gas is more than 500,000 m^3 per day and / or in the marine areas of Poland a compulsory EIA is required	Deep drilling is subject to screening to assess whether the project requires an EIA or not. Surface industrial installations for the extraction of coal, petroleum, natural gas and ores, as well as bituminous shale is subject to screening to assess whether the project requires an EIA or not. Extraction of petroleum and natural gas for commercial purposes where the amount extracted exceeds 500 tonnes/day in the case of petroleum, and 500,000 m^3 per day in the case gas, is subject to a compulsory EIA.

GHG emissions criteria in the EIA

In France, the UK and Poland the EIA must contain general information on emissions resulting from the operation of the proposed projects and the climate impact of the project (no further details are specified). In France, the EIA must also contain measures to compensate, where possible, the project's significant adverse effects on the environment or human health that could not be avoided or not sufficiently reduced, which would be relevant in the case of GHG emissions from shale gas exploitation and exploration (e.g. GHG off-set measures). Similar measures also apply in Poland but they are less detailed. Therefore the EIA requirements in these three countries do not really go beyond the general EU requirements set in Directive 2011/92/EU (EIA Directive).

It should be noted that the Polish government is working on a guideline to be applied for EIA dealing with shale gas exploration and exploitation projects. No information is available on the extent to which it will cover GHG emissions.

[37] According to NY Department of Conservation, multi-well pads could involve 7.4 acres (3 hectares) disturbance per pad in the drilling phase. Information retrieved 23 May 2012 from: http://www.dec.ny.gov/energy/75370.html
[38] The Polish authorities argue that aquifers are located around 1 000 meter depth. This is why they decided to use this criterion.

Findings:

It would be relevant that detailed requirements should be set with regard to GHG emissions.

For example:

- Developers should detail how methane flow back would be controlled and reduced during the exploration and exploitation stage;
- Off-setting measures with regard to GHG emissions should be proposed;
- Study on technologies limiting GHG emissions from methane flow back.

Best practice for well completion

In these three countries, general well completion requirements apply to all hydrocarbon mining activities. However, no specific requirements or guidance have been set with regard to well completion of shale gas exploitation activities.

Requirements for Health and safety of workers

None of the three countries assessed set specific occupational health and safety (OHS) requirements for the exploration and exploitation of shale gas. They rely on the general OHS requirements that apply to the extraction and exploitation of hydrocarbons, mainly transposing the EU legal acts on these issues (e.g. Directive 92/91/EEC concerning the minimum requirements for improving the safety and health protection of workers in the mineral extracting industries through drilling).

6.3.4.1 *Conclusion / Recommendations*

The three countries do not set specific requirements to control GHG emissions from shale gas exploration and exploitation. They instead rely on the application of their mining and environmental legislation. The analysis of EU legislation and a limited number of country studies have shown that the applicability of some EU legal acts e.g. the EIA and the Industrial Emissions Directives, is uncertain and subject to interpretation. In addition the EU requirements relating directly to GHG emissions are often worded in a very general manner, in the EU legislation itself, but also in the national transposing act. In order to adequately regulate GHG emissions from shale gas the following could be further investigated:

- Consideration of the issues identified related to the scope of the EIA Directive with regard to shale gas exploration and exploitation activities (Annex I or II);
- Consideration of information requirements on measures taken by developers to limit GHG emissions under the EIA Directive or possibly other pieces of legislation;
- Consideration of the need for measures to limit GHG emissions for shale gas exploration and exploitation;
- Consideration of the issues identified related to the scope of the Industrial Emissions Directive with regard to shale gas exploration and exploitation activities;
- Consideration of the application of the emission limit values requirements under the Industrial Emissions Directive to methane emissions from exploration and exploitation activities.

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7 Assessment of current GHG emissions reporting framework

7.1 Introduction

This chapter analyses the adequacy of the current GHG emissions reporting framework under the auspices of the UNFCCC and IPCC, and proposes any improvements needed, in relation to shale gas production.

The development of shale gas represents unconventional natural gas production. This implies that conventional GHG emissions reporting frameworks may not be fully adequate to account for the GHG emissions of shale gas. This analysis therefore aims to give the European Commission insight into the adequacy of the UNFCCC reporting framework and IPCC inventory compilation and reporting guidelines to enable the reporting of accurate and complete estimates of shale gas lifecycle GHG emissions.

Shale gas production is in its infancy in Europe, and presents specific challenges for estimation and reporting of releases of GHGs from E&P activities. The research has sought to identify any existing data and emission estimation methods that address these specific challenges, notably with regard to the release of fugitive methane during exploration phases and to well completion.

7.2 Study Approach

The analysis seeks to assess current GHG data reporting practices in the unconventional gas E&P sector, reviewing data reporting at the operator, sector and national level, in order that national GHG inventory data from EU Member States is complete, consistent, comparable, transparent and accurate. In order that the national GHG inventory data from Member States are useful to assess EU-wide implications of unconventional gas E&P, sufficient detail in reported national GHG emissions is needed. Furthermore, without detailed data on unconventional gas E&P GHG emissions by Member State, it will be extremely difficult to assess the data quality reported within the EU and to ensure that the EU-level evidence base for policy decision-making is evolving and improving to reflect developments in scientific understanding of the emission sources and impacts of mitigation actions.

The study has included:

- Review of the UNFCCC Common Reporting Format (CRF) for national GHG inventory submissions;
- Review of the 2006 IPCC Guidelines for National GHG Inventories and the 2000 IPCC Good Practice Guidance (GPG), for the fugitive emissions from energy sector;
- Review of the National Inventory Reports (NIRs) for a number of countries where unconventional gas extraction is known / thought to occur, to review the data and methods used for the gas E&P sector and identify anything specific to unconventional gas E&P. NIRs for 1990-2009 submissions to the UN have been reviewed for: Canada, U.S., Poland, Germany;
- Consultation (via phone and email) with national GHG inventory sector experts for the fugitive emissions from fuels sector from several countries, to research any more detailed available data that underpins the NIR data, and to identify (and consult with) industry regulators that may hold more detailed data specific to unconventional gas E&P emission sources. We have also contacted the lead author of the fugitive emissions from energy chapter of the 2006 IPCC Guidelines and 2000 IPCC GPG (Dave Picard of Clearstone Engineering in Canada) and members of the IPCC Emission Factors Database expert panel (Dr Keith Brown) to seek any additional insight into international efforts to improve the detail and accuracy of national inventory guidance materials (i.e. emission estimation methodological options and emission factors);

- Review of available documentation that the research has identified that has been developed (either by industry regulators and / or national inventory agencies) to provide industry guidance on GHG emission estimation methods for the unconventional gas E&P sector.

The scope of the study encompasses all of the GHG emission sources associated with unconventional gas E&P activities to ensure that a complete overview of GHG reporting is presented. However, the study team has focussed resources on the specific challenges for GHG emission estimation and report from shale gas E&P sources. Many emission sources from shale gas production, flaring, transmission and distribution are already accounted for through guidance developed for other gas production technologies. The research has focussed on sources where uncertainty in GHG measurement, accounting and reporting are highest, to research detailed information and data on the sources of GHG emissions that are specific to unconventional gas E&P activities, including:

- Fugitive methane losses to atmosphere during the initial phases of exploration, drilling, well work-overs and well development to completion, including methane released from hydraulic fracturing flow back water;
- Fugitive gas composition and impacts on flaring emissions of GHGs;
- Accidental releases due to abnormal activities such as loss of integrity of well casings.

The focussing of research effort reflects the lack of a comprehensive evidence base, and hence high uncertainty, for these sources that are specific to unconventional gas E&P activities; whilst reporting of downstream gas treatment, transmission, distribution and combustion sources, as well as ancillary activities such as transport and waste water treatment are well documented and understood within existing reporting frameworks (for conventional gas and other activities). The sources specific to unconventional gas E&P present a new challenge to Member State regulators and inventory compilers. This research seeks to identify the key knowledge gaps and provide recommendations on how the EU may seek to address them.

All emission sources in the shale gas lifecycle have been mapped against the current UNFCCC reporting framework and IPCC guidance (Appendix 2) to assess how the framework incorporates emissions from all sources through the shale gas lifecycle, and whether the IPCC guidance provides comprehensive methodological approaches, particularly regarding fugitive emissions.

7.3 Evaluation of UNFCCC GHG Emission Reporting Frameworks and IPCC Guidelines

7.3.1 Introduction to UNFCCC GHG Reporting and IPCC Guidance

The basic principles that inform the design and development of the UNFCCC reporting framework for national GHG inventories and the IPCC reporting guidance are to ensure that national GHG inventories are accurate, complete, consistent, transparent and comparable.

The UNFCCC GHG inventory reporting system provides:

- Over-arching guidance to inventory compilers via the IPCC Guidelines and Good Practice Guidance, as well as via technical working groups and an Emission Factors Database (EFDB);
- A Common Reporting Format (CRF) to ensure that countries deliver directly comparable national inventory estimates;
- Guidance on the structure and detail of National Inventory Reports (NIRs) to ensure transparency of estimation methods;

  An annual review process to manage global GHG inventory data quality and promote continual improvement in national inventories.

We have reviewed the available reporting guidance, current practice in countries that report shale gas activity emissions and the evolving dataset on shale gas emissions to assess where development of IPCC guidance and UNFCCC reporting formats may be beneficial to augmenting the detail, transparency and accuracy of national GHG emission estimates.

7.3.2 UNFCCC Common Reporting Format

All Member States are required to report annual national GHG inventory data to the EU Monitoring Mechanism (MMD) and the UNFCCC using the Common Report Format (CRF) tables that all Annex 1 countries use for annual submissions to the UN.

The UNFCCC reporting framework is designed such that GHG estimates are reported according to defined, broad source activities from across the economy. It is designed to be flexible enough to accommodate new sources and activities, but is not prescriptive with regards to the detailed sub-sources evident within a specific economic sector, nor with regard to specific technologies.

The reporting structure for GHG sources related to oil and gas E&P is summarised in the table below, with the range of emission sources from activities pertinent to shale gas E&P activities mapped onto the UNFCCC CRF categories.

Key aspects of the UNFCCC CRF and National Inventory Reports reporting system that affect the information available on emissions specific to shale gas E&P are:

- The structure of the CRF tables does not require the reporting of emissions and activity data that are explicitly for shale gas production. Emissions data for shale gas E&P activities are aggregated within the CRF tables with emissions data from conventional gas E&P emissions;
- The details of the estimation methods and source data used to derive emission estimates are required to be reported within the NIR that are submitted together with the CRF tables, but there is a degree of discretion regarding the detail of data and information provided, and issues of commercial confidentiality may be cited to suppress release of supporting datasets such as production data;
- The CRF tables allow for detailed reporting of emissions from different stages in gas extraction, including separate categories for exploration, production, transmission and distribution. In many CRF submissions, this level of detail is not presented, but emissions are aggregated across the various sources, and sometimes emissions from across oil and gas production are aggregated due to limitations in source data granularity at associated oil and gas production facilities.

7.3.3 IPCC Reporting Guidelines (1996, 2006), Inventory Estimation Methods and the Inventory Review / Improvement Process

The IPCC guidance provides generic methodological advice and it is the responsibility of inventory compilers to generate representative estimates for GHG emissions based on available activity data, emissions factors and (where available) emissions data from site operators or regulatory agencies. The accuracy of estimates submitted to the European Commission and UNFCCC will vary according to information available to inventory compilers, but across the EU all Member States should have implemented robust National Inventory Systems (institutional arrangements, regulations, contracts etc. to secure data provision to the inventory agency) that enable a high degree of accuracy to national estimates for any high-emitting source categories.

Emission estimation methodologies for all sources are presented within the IPCC guidance to provide options at three levels of detail, to enable inventory agencies to adopt a methodological approach that matches the available national data:

- **Tier 1** methods are associated with the highest uncertainty, and typically apply international default emission factors to national activity data, for sources where there are very limited country specific data to use in deriving emission estimates;

Emission = National Activity Data x International Default Emission Factor

[e.g. Emission = gas production (Mth)[39] *x IPCC default factor (CH_4 per Mth gas production)]*

- **Tier 2** methods adopt a similar calculation to Tier 1, but apply a country-specific emission factor to the activity data, and therefore are associated with lower uncertainty than Tier 1 estimates. The country-specific emission factor is typically derived from periodic research across a source sector in the country; an appropriate example here may be that annual or periodic natural gas sampling and analysis surveys be conducted, to determine the typical natural gas composition;

[39] Mth –A Mth is a Megatherm or a million therms

Emission = National Activity Data x Country-specific Emission Factor

[e.g. Emission = gas production (Mth) x National factor (CH_4 per Mth gas production)]

- **Tier 3** methods are applicable where more detailed data is available, and typically involve the aggregation of emissions data reported by operators at the installation level. Within the EU, the existing data reporting systems of EPR, PRTR and EU ETS provide a wealth of detailed site-specific emission estimates that are derived based on a combination of emission monitoring data and emission estimates based on the best available local data. The Tier 3 estimates are associated with lower uncertainty than Tier 1 or Tier 2.

Emission = ∑Site-specific emission estimates

The review of National Inventory Reports indicates that there are examples of both Tier 2 and Tier 3 methods evident for the countries where unconventional gas E&P occurs:

- ✓ **Tier 2**: Country-specific studies / factors used in the derivation of oil and gas sector GHG inventory estimates for Germany, Poland and Canada;
- ✓ **Tier 3**: Shale gas basin-specific reporting used in the U.S. (which may include installation-specific data but none that are publicly available).

Furthermore, based on consultation with environmental regulators and GHG inventory compilers:

- A study has been commissioned by Environment Canada (the GHG Inventory Agency for Canada) to overhaul the Upstream Oil and Gas (UOG) sector estimates, which will include consideration of the shale gas sources in Canada. This study is due to report its findings during 2013;
- Work is on-going in Germany to overhaul the GHG inventory estimates, to update the estimation methods and factors available for national inventory reporting in time for the next inventory reporting cycle. The outcome is expected to be a Tier 2 reporting method that is based on the latest available data. Note that there is currently very little shale gas E&P activity in Germany, but around 300 hydraulic fractures have been conducted in around 30 years for tight gas;
- The U.S. EPA has recently finalised its GHG Reporting Protocol guidance note for the upstream oil and gas sector (U.S. EPA, 2011b), and this provides equations and default factors for site operators to derive well-specific fugitive methane estimates, for unconventional shale gas E&P sources. It is anticipated that once the company reporting of well-specific estimates develops in the U.S., that these estimates will be used to inform the national inventory estimates, to further develop the Tier 3 estimation method currently employed.

The annual review process of national inventories by UNFCCC Expert Review Teams may require additional, more detailed information to be demanded of inventory agencies. This may lead to improvements in inventory detail and transparency over time. Through existing EUMM Working Group meetings for GHG inventory compilers, transparent and detailed descriptions of emission estimation data sources and methods could be promoted amongst the inventory community.

7.3.4 Shale Gas E&P GHG Emission Sources: New Challenges

The development of GHG inventory estimation and reporting systems to accommodate additional sources pertinent to shale gas E&P presents a number of new challenges to GHG inventory compilers. The shale gas E&P sources fall into three broad categories when considering the need for development of new data sources and GHG inventory methods:

- **No new data or methods needed:** For several emission sources from shale gas E&P activities the existing national inventory data and methods should adequately cover the shale gas industry emissions, such as: transport, manufacture of chemicals used in hydraulic fracturing manufacture. No inventory data / method development should be needed, and no additional guidance required.

- **New gas compositional data is needed to derive emission factors representative of shale gas:** For emission estimates that require gas compositional data to inform emission factors, the development of shale gas resources will infer a need for new, more frequent and basin-specific or well-specific gas sampling and analysis, in order to derive emission factors that are representative of shale gas composition, which is more variable than conventional gas composition. Examples include: fugitive releases from equipment (e.g. flanges, compressors, pipelines), gas flaring, gas venting (where used, and where measured volumes are available), shale gas combustion, gas processing and gas leakage from the transmission and distribution networks. There should be no need for any additional method development or guidance, other than the development of a resource of shale gas composition data that could be applied in estimation methods where no such compositional analysis is available to the inventory compilers. In addition to these sources, the national inventory methods for estimating emissions from waste water treatment and disposal may need to be reviewed. Specific work to derive emission estimates from this source may be needed, to reflect the increasing demand for waste water treatment and the removal of specific chemicals and contaminants from flow back fluids. Once again, though, no fundamental requirement for new methodological guidance is required.

- **New source emission estimation methods / guidance and additional data (e.g. new emission factors) will be required:** There are a number of emission sources that are unique to shale gas E&P, for which entirely new estimation methods / guidance and source data will need to be developed in order that inventory estimates can be made. The method options for MS inventory agencies will be determined by the scope, detail and accuracy of any industry-sourced estimates (typically through operator reporting to environmental regulatory agencies under regulations such as EPR / IPPC) for site-specific annual emission estimates. Ideally, where new emission estimates from operators that are specific to shale gas sources become available, this data will provide the basis for complete, consistent and transparent inventory estimates. However, in the event that installation-specific, source-specific emissions data do not become available, that are comprehensive, transparent and consistently provided for all shale gas E&P sources / sites, then the inventory agency will need to seek alternative data sources (perhaps periodic industry studies) to supplement any available activity data (e.g. on gas venting and flaring, or perhaps numbers of well completions, well work overs or overall shale gas production). The main emission source in this category is <u>fugitive / vented releases of gas from drilling, exploration to well completion</u>, including the management of methane-containing hydraulic fracturing flow back fluids. U.S. information sources indicate that this is a source of high methane emissions during the period of hydraulic fracturing and well completion. This source will need to be the focus of specific research within the EU, in order that gas operator reporting to MS environmental regulators is sufficiently detailed and accurate to develop a suitable evidence base for inventory reporting and policy development.

The table below illustrates how shale gas emission sources map onto the existing reporting frameworks and IPCC guidelines. The table seeks to highlight where guidance or reporting detail is either missing, or it is unclear whether existing UNFCCC and IPCC systems fully cover the matters of concern, as well as summarising where the existing reporting guidance and frameworks are satisfactory for sources associated with shale gas.

Table 27: Shale Gas Sources – Gap Analysis for UNFCCC Reporting and IPCC Guidance

Shale gas life cycle emissions source	UNFCCC Reporting category & description	Comments on current structure and recommendations for improvements	IPCC Guidance	Recommendations for further development of GLs
Exploration and Production				
Drilling, hydraulic fracturing, well work-overs, well testing, development and completion	**1B2biii1: Exploration - All Other** (fugitives, gas well drilling, drill stem testing, well completions including releases from methane in hydraulic fracturing flow back fluids)	Reporting structure is not specific to shale gas and hydraulic fracturing so emissions from a range of activities will be aggregated in this field in the CRF. Activity data reported in the CRF does not specifically cover shale gas only activities (well work-overs, hydraulic fracturing). These data would be aggregated with other information. Would be useful to have this data displayed separately for data quality checking purposes.	General guidance on how to select a calculation method, with calculation methods for each Tier set out. Default emission factors for Tier 1 calculation given, but these are not specific to shale gas extraction.	Development needed to provide more complete guidance on methods applicable to unconventional source activities, and to provide detail for underlying datasets (e.g. default emission factors) for: • Drilling / hydraulic fracturing; • Well testing, development and completion. Need to also consider the **gas compositional data**, which in current guidelines will reflect conventional gas composition range.
Flaring	**1B2bii: Gas Flaring**	Not specific to shale gas. Reported data and activities will be aggregated across all gas production. Ideally, conventional and unconventional gas flaring would be separate.	Existing guidance and methods will be applicable to shale gas E&P activities.	Development needed for **gas compositional data** and typical flare gas emissions. Flare gas performance data for variable pressure systems and gas management units specific to shale gas extraction may need to be developed.
Venting	**1B2bi: Gas venting**	Not specific to shale gas. Reported data and activities will be aggregated across all gas production.	Existing guidance and methods will be applicable to shale gas E&P activities.	Development needed for **gas compositional data** and typical vented gas emissions.
Fugitives	**1B2biii2: Production – All Other** (fugitives, wellhead to processing plant to transmission system, well	Reporting structure is not specific to shale gas and hydraulic fracturing, so a	Current GL's offer guidance on calculation of flaring, but not specifically to methods for	Development needed to provide more complete guidance on methods applicable to

Shale gas life cycle emissions source	UNFCCC Reporting category & description	Comments on current structure and recommendations for improvements	IPCC Guidance	Recommendations for further development of GLs
	servicing, gas gathering, processing, waste water processing and disposal).	number of activities will be aggregated in this field in the CRF. Also for reporting of supporting activity data there is no allowance for reporting activities specific to shale gas, such as volume of flow back fluids.	unconventional gas sources.	unconventional source activities, and to provide detail for underlying datasets (e.g. default emission factors) for: - Emissions from flow back fluids - Well work-overs in shale gas hydraulic fracturing. Need to also consider the **gas compositional data**, which in current guidelines will reflect conventional gas composition range.
Combustion processes	**1A1c: Other energy supply** (Gas Combustion in gas supply systems).	Not specific to shale gas. Reported data and activities will be aggregated across all gas production.	Existing guidance and methods will be applicable to shale gas E&P activities.	Development needed for gas compositional data and typical gas combustion emissions, where produced gas is used to run combustion units.
Land Use Change - Land clearance for well pad construction	5 LULUCF.	**Complete** coverage.	**Complete** coverage.	All aspects covered by existing guidance – nothing bespoke needed for shale gas activities.
Waste Water	**6B1 Industrial Waste Water (96GL)** **4D2 Industrial waste water treatment and discharge (2006 GLs).**	Reporting of wastewater from shale gas production would be aggregated with other industrial waste water emissions.	Reporting of wastewater covered by GLs.	Potentially would need to investigate whether, due to the composition of the wastewater, current emission factors could be applied or whether new ones specific to shale gas waste water treatment would be needed.
Processing				
Processing - Gas treatment	1B2biii3 Processing – All Other (fugitive emissions, gas processing).	**Complete** coverage.	**Partial** coverage.	Development needed to explore the completeness of guidance and detail of any underlying datasets (e.g. default emission

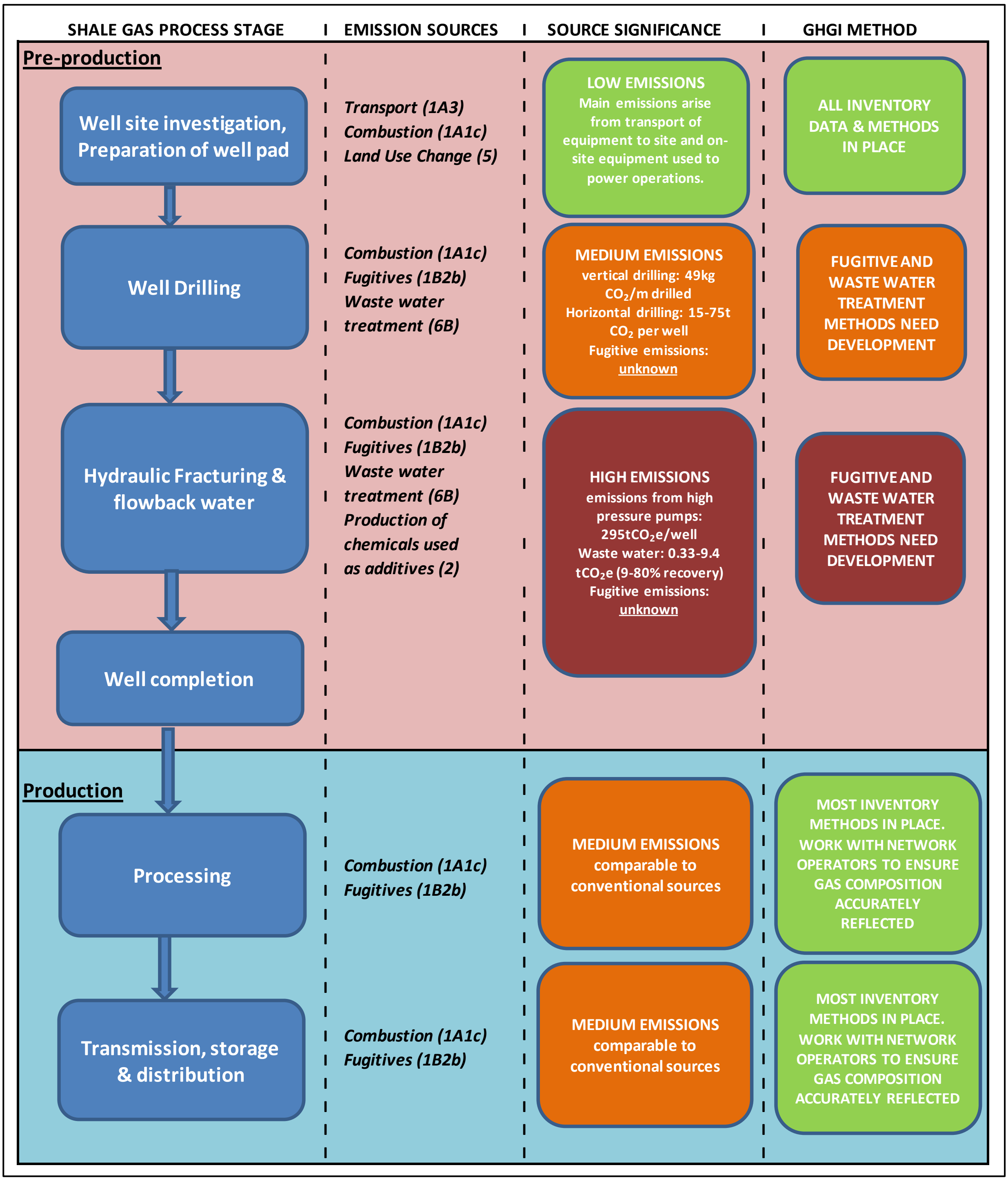
Shale gas life cycle emissions source	UNFCCC Reporting category & description	Comments on current structure and recommendations for improvements	IPCC Guidance	Recommendations for further development of GLs
- Fugitives - Combustion processes - Compression and injection to pipelines	1A1c: Other energy supply (Gas Combustion in gas supply systems).			factors) for: • Gas treatment; • Fugitives. Other aspects covered.
Transmission and Storage - Combustion processes - Gas pipeline leakage - Other Fugitives	1B2biii4 Transmission and Storage – All Other (fugitive emissions, pipeline leakage). 1A1c: Other energy supply (Gas Combustion in gas supply systems).	**Complete** coverage.	**Complete** coverage.	All aspects covered by existing guidance – nothing bespoke needed for shale gas activities.
Distribution - Gas network leakage - Other fugitives	1B2biii5 Distribution – All Other (fugitive emissions, pipeline leakage)	**Complete** coverage.	**Complete** coverage.	All aspects covered by existing guidance – nothing bespoke needed for shale gas activities.
Other sources - Well blowouts - Pipeline ruptures	1B2biii6 Other– All Other (well blowouts, pipeline ruptures, dig-ins).	**Complete** coverage.	**Partial** coverage.	Development needed to address certain technology-specific aspects of shale gas activities, whilst underlying method is evident.
Transport - Road transport - Rail - Shipping	1A3 Transport *(National inventories only cover domestic shipping, with international shipping estimates reported as memo items only).*	**Complete** coverage	**Complete** coverage.	All aspects covered by existing guidance – nothing bespoke needed for shale gas activities.
Gas Combustion	1A1: Energy.	**Complete** coverage.	**Partial** coverage.	Methodology is fully covered by existing guidance; nothing bespoke is needed for shale gas activities. The only development required

Shale gas life cycle emissions source	UNFCCC Reporting category & description	Comments on current structure and recommendations for improvements	IPCC Guidance	Recommendations for further development of GLs
				by inventory compilers is to ensure that the national gas compositional analysis reflects the contribution from shale gas. It would be useful, therefore, for the guidance to provide examples of the typical ranges of shale gas composition to support the development of national gas GHG emission factors.
Manufacture of chemicals used in hydraulic fracturing	2: Industrial processes.	**Complete** coverage Emissions from manufacture of chemicals used in hydraulic fracturing will be aggregated with all other chemical manufacture emissions.	**Complete** coverage.	Estimation methods are fully covered by existing guidance; there is nothing bespoke needed for shale gas activities.

7.3.5 Review of IPCC 2006 Guidelines, 1996 Guidelines and 2000 Good Practice Guidance & other literature

The main challenges to GHG inventory emission estimation and reporting from shale gas E&P sources are summarised in Figure 9 below, taken from a recent study on behalf of the UK Department of Energy and Climate Change (AEA, 2012):

Figure 14: Shale Gas E&P Processes, Emission Sources and GHG Inventory Impacts



Emission estimates presented in this figure are taken from Broderick et al, 2011.

Key findings from the review of the IPCC guidelines and Good practice guidance are:

- **Key finding 1**: The 2006 IPCC Guidelines do not specify how to calculate emissions from shale gas activities. Methods and emission factors are outlined for conventional gas extraction.

Recommendation: The development of emission factors, estimation protocols and data on typical shale gas composition is needed to provide operator and inventory guidance on estimating emissions from sources that are specific to shale gas E&P. Whilst this could be implemented at the IPCC level and any factors put forward for inclusion within the IPCC Emission Factors Database (IPCC EFDB). At EU level, any research into methods and emission factors for calculation of shale gas emissions carried out by Member States or by industry or other research bodies, could be shared between countries at relevant Working Group meetings. This would help encourage consistent working across the EU.

- **Key finding 2**: Fugitive / vented methane from hydraulic fracturing, well completions and well work overs are a new source of additional GHG emissions for EU inventory compilers to manage, and therefore a new emission estimation methodology and emission factors will need to be developed to cover these sources. Estimating these fugitive emissions from shale gas E&P activities is the main challenge to reporting complete and accurate GHG emissions. Available datasets on gas composition, activity data and factors affecting fugitive methane levels is disparate. Many emissions arising from the different processes are very site specific and can be complicated by many factors. For example, gas produced from flow-back fluids may be contaminated with carbon dioxide or nitrogen injected as part of the hydraulic fracturing or well completion. Methane may not only return in the gas phase but also dissolved in the flow-back fluid, under high pressure, and the guidelines provide no method applicable to this source. Open pit collection will allow the methane to be released, whilst enclosed tanks facilitate collection for recovery or flaring.

Recommendation: Methods for oil / water / gas separation plant which are already included in the IPCC guidelines for inventory compilation may provide an option that can be modified for shale gas, whilst U.S. sources do provide some emission estimation methodologies and default factors for estimating the GHG emissions from unconventional well gas completions and work-overs. Further research into appropriate emission estimation methods and emission factors from fugitive emissions are required.

- **Key finding 3**: The composition of shale gas differs from conventional gas; U.S. sources indicate that shale gas exhibits a wider range of gas composition (e.g. hydrocarbon and carbon dioxide content) compared to conventional gas. The composition of shale gas differs according to the local basin geology.

Recommendation: Research is needed to assess shale gas composition and emission factors for shale gas basins under development in Europe. The variability of the shale gas composition observed in U.S. sources indicates that in order to ensure representative emission factors, shale gas compositional analysis will need to be conducted with greater frequency and at a more detailed geographical level (e.g. at least gas basin-specific, if not well-specific), and that emission estimation methods will need to reflect the local composition of the shale gas to minimise uncertainties. Use of “default” emission factors will introduce greater uncertainty for shale gas sources than would be the case for conventional gas sources.

- **Key finding 4**: Many of the emission sources pertinent to conventional gas E&P are also sources from unconventional gas E&P. Therefore methods outlined for conventional gas extraction can be applied, provided that new emission factors to represent the shale gas composition are developed and applied at the well- or basin-level (as shale gas composition, including hydrocarbon and carbon dioxide content, differs from conventional natural gas and exhibits more variability according to local geological conditions). Combustion and fugitive emissions arising from components (valves, flanges, compressors etc.) during well construction, drilling and fracturing and completion are also covered by existing methodological guidance and reporting. However, there will be a need to develop shale gas specific emission factors to reflect shale gas composition, where shale gas is used directly to fuel equipment.

Recommendation: Whilst estimation methods developed for conventional gas extraction can be used for shale gas E&P sources, caution needs to be applied. For example, when estimating emissions from gas flaring, there are operational issues specific to shale gas E&P that may inhibit the estimation accuracy, where more inconsistent or low flow rate of gases may make it difficult to sustain a flame on a traditional flare stack. Therefore, whilst pilot flames or periodic venting may be operational solutions, these may require additional detail of reporting by operators (e.g. of flaring and venting volumes, of flare gas composition) to ensure a complete, accurate emission estimate is reported.

Emissions from components arise from engines that power the process of blending fracturing materials, pumping from storage vessels (water, chemicals and sand), compression and injection of the fracturing material into and out of the well. No additional guidelines or revisions to reporting structure are recommended, but as outlined already, some work to derive shale gas compositional data will be needed where the gas is used to fuel the engines.

- **Key finding 5**: The UNFCCC reporting framework is aligned with the final fuel type (e.g. oil, gas, coal etc.), and is not technology-specific.

Recommendation: Further disaggregation of reported emissions and the provision of tailored emission estimation methods would be needed to deliver data specific to unconventional gas E&P sources. However, so long as estimates of fugitive emissions are transparent, accurate and reliable there would be no need to add a separate source category to the CRF tables

- **Key finding 6**: High volumes of waste water are produced during shale gas extraction, which contain chemicals and flow back contaminants. Contaminated waste water and other contaminants (such as heavy metals, NORMs from the shale formations) will need to be treated and disposed. One report from the U.S. EPA (2011) suggests that 9092m^3 – 18,184m^3 [36] of water are typically needed per well during the fracturing process. This report also indicates that, based on a total fracturing fluid volume of 13,638 m^3 [40], the total volume of chemical additives in fracturing fluids range from 68.19 – 72.74 m^3 [36] (0.5% - 2% by volume). The additional burden of water treatment may lead to higher direct GHG emissions (waste water is a source of methane when treated or disposed of anaerobically, and nitrous oxide emissions can also occur from the waste water treatment process). (e.g. of methane and nitrous oxide and VOCs at the treatment works, to process higher volumes of waste water). The higher volumes of waste water to be treated will increase the significance of this source in the national inventory context and MS may need to review their waste water treatment and disposal inventory method as a consequence. For example, if new higher emissions for this source lead it to be assessed as a new Key Source Category in the national inventory, then the accuracy of the method will come under greater scrutiny and the MS will be required to prioritise improvements to the method.

Recommendation: Whilst the guidelines provide methodological information to support estimates from waste water treatment and disposal, this is potentially an area where additional research is needed to develop guidance and factors to apply to the estimates for treatment of the (typically very high volumes of) shale gas waste water that needs to be treated. Through the treatment of shale gas waste water, additional direct emissions of methane, nitrous oxide and VOC can be expected; research is recommended to assess the level of additional emissions that this waste water treatment will lead to, and whether the characteristics of the waste water and in particular of the hydraulic fracturing chemical and methane content of this waste water has a notable impact on the emissions of GHGs per unit volume of water treated.

7.3.6 Review of National Inventory Reports and Consultation with Inventory and Industry Experts

The research of NIRs has provided some useful additional information regarding the level of detail of data typically available to inventory agencies, with a lack of transparency notable in the majority of cases. We have consulted with National Inventory compilers from North America and Europe.

7.3.6.1 *Canada*

The Canada GHG inventory does not provide any methods or emission factors specific to shale gas extraction, and is based on a detailed Upstream Oil & Gas (UOG) sector study from 2000, with emissions then scaled across the time series using specific indicators for sub-sectors of the UOG sector. Environment Canada has recently commissioned a new UOG study to update the inventory estimates for fugitive emissions from energy sources and is expected to be finalised is 2013. This study is expected to derive emission estimates for shale gas E&P sources in Canada, but there is no data specific to shale gas available at the date of publication according to the lead author of the study, Dave Picard of Clearstone Engineering, who was also the lead author of the fugitive emissions from energy sector chapter in the 2006 IPCC Guidelines.

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[40] 1 Imperial gallon = 0.00454609188 cubic metres (15,000-60,000 gallons converted)

Tables in the Canada NIR provide a series of component average emission factors for estimating total hydrocarbon emissions from fugitive equipment leaks at natural gas production and processing facilities, which are applicable to unconventional gas E&P.

Information from the Canadian state regulators of oil & gas E&P provides useful examples of activity data and emissions data that help to underpin shale gas E&P emission estimates; it would be beneficial to the GHG emission inventory compilation methods within the EU if site operators were obliged to report activity data and emissions data to a similar level of detail. The regulator reports from the Oil & Gas Commission in British Columbia are available at:
www.bcogc.ca/publications/reports.aspx

Annual reporting by operators in Canada for both conventional and unconventional natural gas E&P, includes:

- Total flared gas volume and solution gas flaring volume (which is primarily aimed at gas produced at oil wells, but could be applied to unconventional gas well flow back fluids);
- Annual gas production (by well, by installation);
- Well clean-up and well testing flaring (including information on well work-overs and re-fracturing activity in unconventional production);
- Total gas vented volume;
- Number of wells drilled;
- Incident types / causes (e.g. blowouts due to hydraulic fracturing, unplanned gas releases, fires etc.);
- Other reports require activity data useful for inventory compilation, including;
- Number of hydraulic fracturing activities (Number of fracturing stages per well; volume of fluid used for each stage);
- Number of well completions and well work-overs;
- Volume of waste water treated and hydraulic fracturing flow back fluid volumes;
- Description of Reduced Emissions Completion mitigation techniques employed.

7.3.6.2 *U.S.*

There are a range of sources from the U.S. that provide data and emission estimation methods for shale gas E&P sources, and specifically the U.S. information sources do provide examples of estimation methods and factors to estimate the fugitive methane emissions from unconventional gas well completions, well work-overs and handling of flow back fluids. The study team has reviewed the National Inventory Report method description, reviewed recent methods and factors developed by the U.S. EPA for their GHG Reporting Protocol programme and also researched industry information published via the U.S. EPA Natural Gas STAR (voluntary reporting) programme, and we have consulted with a number of U.S. experts on shale gas emissions.

There are a wide range of emission factors and estimates in recent U.S. literature, and there is evidently a high degree of variability and uncertainty in estimates of fugitive methane from shale gas well completions. During 2011, the U.S. EPA finalised a “clean” version of emission estimation methods and emission factors for oil and gas operators to use for reporting under the (new) GHG Reporting Protocol. The U.S. EPA published a supplementary technical guidance document in April 2012 to summarise their findings following a review of industry literature to derive an emission factor for unconventional gas well completions. The guidance note and emission factors were developed in consultation with industry, and these U.S. EPA resources appear to be the most detailed information available to support estimation of fugitive methane emissions from shale gas E&P sources:

- The GHG Reporting Protocol provides a detailed estimation methodology for operators to use to derive emission estimates from unconventional gas well completions, taking account of different variables such as flow rates and duration of hydraulic fracturing fluid flow back. Estimation calculation equations are provided for instances where mass flow is measured / estimated, or where mass flow rate is measured / estimated.
- The U.S. EPA technical documentation to support the GHG Reporting Protocol provides emission factors for unconventional well completions and work-overs.

Several methods have been explored by the U.S. EPA to derive a recommended emission factor for unconventional gas well completions; a factor for shale and tight gas formations is cited as 11,025 Mcf per well completion, which equates to 312,007.5 m^3/completion (unmitigated), or 167 tCH_4

(3,503 tCO_2eq). The U.S. National Inventory Report (2011[41]) includes an insight into the data and estimation methods that are available to the inventory agency in the U.S., on the basis of operator-reported data to regulators, which could provide a template for development in the EU. The NIR presents emission factors and methods for the calculation of emissions from unconventional gas wells. Data is available at a high level of detail with factors provided for:

- leaks from specific components (heaters, separators, metremetres, piping, compressors etc.);
- flaring and venting;
- periodic sources such as drilling, well completions, well work-overs and well clean-ups.

Regional emission factors are presented, giving an insight into the range of shale gas compositions from fields across the U.S. "Typical" emission factors for unconventional gas E&P sources include:

Table 28: Typical emission factors for unconventional gas E&P

Source	***U.S. NIR factor (Table A-120)***	***tonnes methane***	***Tonnes CO_2eq***
Gas well completion flaring	21.84 m^3 of gas / completion[42]	0.01 per completion	0.25 per completion
Unconventional gas well completion (*no mitigation*)	~215,600 m^3 of gas / completion	~117 per completion	~2,925 per completion
Unconventional gas well work-over (*no mitigation*)	~215,600 m^3 of gas / completion	~117 per completion	~2,925 per completion
Gas well drilling	75.6 m^3 of gas / well	0.04 per well	1 per well
Gas well clean-ups (LP wells)	~39,200 m^3 of gas / well	~21 per well	525 per well

**Conversion to mass basis assumes 78.8% mole fraction of methane in gas.*

The U.S. National Inventory Report also presents the emission compilation approach, combining the regional gas compositional data with detailed bottom-up gas-field estimates, component inventories and activity data for specific activities (such as number of wells drilled per year, number of unconventional well completions per year, number of unconventional well work-overs per year).

National inventory estimates of fugitive methane emissions from oil and gas sources are presented according to activity, to a level of detail that includes:

- Unconventional gas well completions;
- Unconventional gas wells work-overs;
- Component fugitives;
- Well clean-ups (LP wells).

The U.S. NIR therefore provides the most detailed presentation of fugitive emission estimates from shale gas E&P sources from the NIRs reviewed in this study. The U.S. approach is an IPCC Tier 3 methodology that applies field-specific gas compositional data and local activity data, combined using documented industry methodological guidance. The level of detail provided in the NIR reflects the commensurate high degree of detail in installation-level reporting guidance in the U.S. for the industry, which reflects the length of time that the technology has been utilised in the U.S.

The data is transparent and consistently reported across all regions, although the accuracy of the emission factors is subject to on-going scrutiny and the reporting uncertainty is high. We also note that the data in the NIR is based on emission factors that date back to earlier studies (U.S. EPA 2004, 2006); new emission factors have subsequently been derived and published within the 2011 U.S. EPA GHG Reporting Protocol Sub-Part W for the oil and gas sector.

7.3.6.3 *European Union*

Consultation with Pollutant Release and Transfer Register (PRTR) regulatory experts from the **European Environment Agency** indicated that the reporting of emissions from shale gas E&P sources is not explicitly included within the scope of PRTR. Some Member States have included

[41] http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html
[42] 1 cubic foot = 0.028 cubic metres

estimates of fugitive emissions within submissions for co-located combustion activities which indicates some degree of variable interpretation of the scope of PRTR reporting within the EU; some operators and regulators may consider that shale gas E&P sources fall within “Mining and underground activities” within PRTR national reporting.

In the **Netherlands**, the GHG inventory compilers for fugitive releases from the energy sector (PBL) has provided an industry-wide protocol that is used by all operators in the sector, including onshore gas operators. Although this is useful to understand the overall approach to emission estimation and reporting, the protocol does not provide details of emission factors for specific sources. We have not identified evidence to suggest that there has been any significant unconventional shale gas E&P activity in the Netherlands to date; the Dutch protocol does not cover any estimates of emissions from shale gas well completions and handling of flow back fluids. A consultee from PBL stated that:

“The ten Dutch Oil and Gas operators all use the electronic annual environmental report (e-MJV) to provide their emission and production data. They are not obliged to fill in the PRTR reporting module but use a special Oil and Gas module. The e-MJV data of all operators are controlled and approved by the Ministry of Economic affairs, Agriculture and Innovation (Directorate Energy market), their competent authority. We use the approved emission- and production data to report in the Common Reporting Format. So yes, the operators do use detailed data of their installations to calculate their emissions but unfortunately the emissions and production data are only available in aggregated form”.

Review of the operator reporting guidance and periodic industry publications has provided an insight into the level of detail at which emission calculations are performed by Dutch oil and gas companies, and therefore the level of data granularity (e.g. of activity or emissions data for specific sources) that may be available to the companies in deriving the estimates. Although there are no published estimation methods and emission factors for the reporting of fugitive methane sources from onshore gas sources, the detailed source-specific analysis that is presented within energy conservation plans from Dutch oil and gas companies indicates that individual companies have developed their own approaches to estimating fugitive emissions from specific equipment types, to combine with their inventories of their operational equipment; for example, these plans / publications identify potential savings or changes to practices for specific pieces of equipment, such flares, vents or furnaces.

Consultation with national GHG inventory experts and PRTR regulatory contacts in **Germany** has identified that there are no shale gas E&P sites in Germany reporting under PRTR and the data available from operators are aggregated by site with no detail on source-specific emissions. Hydraulic fracturing has been used in Germany since the 1960s; around 300 fractures have been conducted nationally in that time, indicating the relatively low uptake of this extraction technology to date. In addition, these fracturing jobs were not using high volume hydraulic fracturing, which is used for shale gas projects. Activity data and inventory estimates in Germany are not available at a level of detail to enable specific technologies to be identified, or even to present explicit emission estimates for upstream oil and upstream gas activities separately. The current national inventory method does not provide any data specific to shale gas E&P, but there is an on-going study due to report later in 2012 (UBA, 2012) that is aiming to derive country-specific emission factors for oil and for gas E&P sub-sectors. The Association of Oil and Gas Producing (WEG) in Hannover is the lead organisation in the development of operator guidance.

Review of the National Inventory Report for **Poland** indicates that emission estimates used in the national GHG inventory are derived from a country study, but the details of the emission factors used at the source-specific level are not available.

7.4 Summary

There is currently no production of shale gas in the EU, and consequently very limited information on shale gas activities and emissions within the EU. The study has identified no emission factors, GHG estimation methods or industry activity or emissions data specific to shale gas E&P sources within the EU. Operator reporting of emission estimates (in EU Member States where hydraulic fracturing occurs) is typically aggregated at the installation level, with no transparency of emissions of methane from specific fugitive or vented sources or from specific activities on the site.

Existing reporting guidance provides information and methodological options that could underpin new regulatory reporting guidance applicable to the shale gas sector, noting they do not cover some of the highest-emitting sources specific to shale gas E&P, such as well completions, management of hydraulic fracturing flow back fluids and well work-overs. Information and reporting protocols from regulators in Canada and the U.S. provide estimation methods and indicative emission factors for these sources that are specific to shale gas E&P, which could be developed for application in the EU.

IPCC Guidelines do not provide emission estimation methodology details or emission factors that are applicable to calculate emissions from sources specific to shale gas E&P such as well completions, well work-overs and the related management of flow back fluids.

The UNFCCC reporting format (CRF) does not require that countries specify GHG emissions from shale gas E&P, or from any other specific technology or sub-sector. Emissions and activity data are typically reported by countries at an aggregated level across all gas E&P sectors, with additional methodological detail provided within National Inventory Reports (NIRs). The level of detail provided regarding emission estimations within the NIRs is subject to the discretion of the inventory agency, although this can be influenced through UNFCCC Expert Review Team feedback.

Several process stages in shale gas E&P, including processing and compressing the gas for distribution, require the same steps as with conventional gas. Therefore, the current IPCC Guidelines and national GHG inventory methodologies should be adaptable to allow inventory agencies to derive complete and accurate estimates for these sources. Development of appropriate emission factors (ideally at the gas-basin level) through gas sampling and compositional analysis will be required to ensure that emission factors reflect the local shale gas composition, which is typically more variable than that exhibited by conventional gas. The shale gas content of methane, other hydrocarbons and carbon dioxide varies between shale gas basins, which implies a need for more routine gas compositional analysis in deriving emission factors and developing the evidence base for shale gas emission factors in the EU.

Fugitive methane emissions from hydraulic fracturing and management of flow back waters are sources of GHG emissions that do not arise from conventional extraction. Information on emission estimation methodologies and indicative emission factors for shale gas well completions and work-overs are only evident from U.S. industry and U.S. EPA information sources. As shale gas E&P grows in the EU, these are expected to be the most significant new sources of GHGs for Member State GHG inventories to cover, and they also present the biggest challenge methodologically.

There are industry-specific, source-specific emission estimation protocols and factors developed by the U.S. oil and gas industry and the U.S. EPA, and a final “clean” version of GHG Reporting Protocol documents for the U.S. oil and gas sector was published in December 2011. Shale gas E&P with hydraulic fracturing is an established technology in the U.S. but despite this there remains a lack of clear, detailed data to provide the evidence base for determining emission factors for specific sources. The high level of uncertainty in emission factors for shale gas well completions is reflected by the on-going challenges to published data, protocols and emission factors by the U.S. oil industry and other stakeholders. This level of uncertainty is highlighted by Pétron et al (2012), who applied dispersion modelling analysis techniques to estimate overall methane loss to the atmosphere around a U.S. shale gas field and estimated emissions at a level double that estimated by the U.S. EPA methodology.

There is a high degree of uncertainty in the existing dataset for estimating fugitive methane emissions from shale gas E&P sources, which present challenges to all regulatory and reporting agencies. Investment is needed in regulatory development, measurement and reporting protocols and guidance that promotes a high degree of transparency and accuracy to emission estimates, together with a robust programme of data checking, benchmarking and verification by regulators and inventory agencies.

Development of GHGI Estimation Methods for EU MS Inventory Agencies

The growth of shale gas E&P in the EU introduces new challenges to inventory compilers across Europe, with new sources of GHGs for inclusion in national GHG inventories. For many emission sources associated with shale gas E&P, it is expected that current data provision and estimation methods will enable inventory agencies to compile comprehensive and accurate national estimates. The main new challenges to inventory agencies will arise for:

- fugitive and vented methane emissions from well drilling to well completion, and from well work-overs;
- collating new data on shale gas composition, to develop more representative emission factors for sources where existing estimation methods could be applied to shale gas E&P sources (such as flaring, gas leakage and fugitive releases from site components);

- GHG emissions from waste water treatment and disposal, where the new demands for treatment and disposal of high volumes of hydraulic fracturing flow back water may necessitate a revision to the national estimation method and source data.

Inventory agencies from across Europe will need to address these new challenges through sourcing new data from industry in order to derive GHG estimates for the most significant potential new sources of emissions, especially fugitive and vented methane from well completions. In this regard, inventory agencies will need either:

i. Detailed, comprehensive, source-specific emission estimates from industry site operators; or
ii. Detailed periodic industry research to provide emission factors for shale gas E&P sources together with the annual activity data required to compute estimates for each of those sources.

The availability of data will then determine the available methodological options for the inventory compilers. Where source-specific estimates become available, i.e. option (i) above, then the inventory compilation method could simply aggregate these data, provided that complete reporting coverage for all shale gas sites is achieved nationally, thus:

Emissions = ∑ installation reported data, by source

Where this approach is adopted quality checking of emission estimates should include checking of available activity data such as: gas venting and flaring volumes, numbers of hydraulic fracturing activities, shale gas well completions and work-overs, volume of flow back water treated. Through the application of factors and methods from U.S. based industry reporting protocols, top-down estimates for the industry would enable sense-checking of the operator-reported data, and the identification of any data inconsistencies that may warrant further investigation.

For option (ii) above inventory compilers will need to have access to annual detailed activity data for specific sources in order to estimate emissions using (ideally) basin-specific emission factors.

Emissions = Activity Data x Emission Factor

It is anticipated that the on-going studies in Canada and Germany may help to derive options to support such methodological developments. We also note that in applying this proposed inventory compilation approach, uncertainties would be reduced if the data were available to distinguish between different groups of sources (such as sources with or without reduced emissions completions, or sources from different producing basins), and carry out the calculations separately for these groups followed by aggregation of the estimated emissions.

In all cases, local gas compositional data will need to be obtained through gas sampling and analysis, to ensure that emission estimates or factors are representative of the shale gas quality in that basin.

The level of additional GHG emissions from waste water (flow back) treatment and disposal are uncertain, and further research into this source is one of the recommendations of this study; based on the limited information from review of literature, the additional waste water emissions from shale gas E&P activities are expected to be modest in comparison to fugitive methane sources from well completions. We also note from UK GHGI experience that the research and resourcing of inventory estimation methods reflect the historic significance of that source nationally.

Therefore, it is anticipated that the potentially large increase in demand for waste water treatment due to the need to treat high volumes of hydraulic fracturing flow-back fluid will test the rigour of national methods already in place for this source. Typically, within EU MS inventories this is a low priority emission source. A shift in activity levels due to shale gas production could elevate waste water to becoming a Key Source Category in some MS inventories. If countries find that this is the case, it may be that they will need to invest resources into improving their estimates and moving to a higher tier of reporting for this source category. Higher tier methods are presented in the IPCC guidelines, but may require an extra level of investment in the development of emission factors and estimation methods. If this is the case, then it is expected that there will be extra demands placed on some inventory agencies within the EU.

New Research Studies

Environment Canada has recently commissioned a new study to improve national estimates from oil and gas including consideration of shale gas E&P, which will report in 2013. In addition the German inventory agency has an on-going study to improve the detail and accuracy of national estimates for the oil and gas sector. Both of these studies may provide useful, new information, to help inform the development of operator reporting systems and national inventory methods, data requirements and uncertainties.

7.5 Recommendations

Key recommendations are summarised as follows:

7.5.1.1 *General Recommendation*

Development of evidence based, reporting systems, estimation methodologies and emission factors should focus on the most significant and most uncertain new sources of GHG emissions from shale gas E&P sources, which are the fugitive methane emissions from well completions and well work-overs, including the management of hydraulic fracturing flow back fluids.

7.5.1.2 *Harmonising Member State Inventory Reporting and Promoting Good Practice*

It is recommended to promote research within Europe to support Member State development of data and reporting for shale gas exploration and production to ensure consistent, comparable, accurate and transparent GHG reporting.

Working Group meetings (such as WG1 for inventories) could be used as a systematic way of promoting harmonisation of methods across EU MS. Although the EU has no mandatory powers in place to enforce methods of ‘best practice’ discussed at these meetings, they can still be used as a forum for MS to discuss common issues and gain support and advice from others in solving any problems.

In the development of industry-specific guidance on operator reporting and regulation design, the EU should consider the approach developed in Canada including: consideration of the range of operator data reported within British Columbia; the findings of the Jurisdictional regulatory review conducted by the Government of Alberta.

Further useful lessons could be learned by consulting with shale gas experts in the U.S. EPA that have developed the GHG Reporting Protocol “sub-part W” guidance for the upstream oil and gas sector, which includes detailed estimation methods and factors for fugitive methane emissions from shale gas well completions and work-overs. The presentation of detailed tables and methods in the U.S. National Inventory Report provides a high level of transparency to the emission estimates specific to the shale gas exploration and production industry; the U.S. NIR could therefore be used as an example of good practice for Member States to consider as they develop shale gas emissions reporting within National Inventory Reports for submission to the EU and UN.

The EU should also consider engaging with Environment Canada and the German inventory agency to gain an insight / support the on-going studies into upstream oil and gas emission estimates, in order that the study outputs may be of use for the future development of EU-wide guidance or regulation.

7.5.1.3 *GHG Emission Sources, new challenges*

The technical improvements should be prioritised based on the analysis presented in Table 27.

To provide the most accurate and detailed source data for national inventory compilers to work with, environmental regulators within the EU should consider the development of regulatory reporting specific to the oil and gas sector. For example, it may be appropriate to develop new industry, and source specific guidance for operators to use in their annual submissions under EPR / IPPC and / or PRTR. The development of such guidance and protocols should build upon good practice, augmented using U.S. based resources to cover the new (to the EU Member States) emission sources specific to shale gas.

Gas E&P operators and national gas network operators should be encouraged to conduct more regular gas compositional analysis for shale gas, in order to develop a more robust evidence base for the development of emission factors for shale gas E&P sources in the EU. Ideally the evidence base should at least target the development / compilation of gas compositional data at the gas-basin level, if not at the well-level.

7.5.1.4 *Research*

Given the high level of uncertainty evident in the literature from the U.S. regarding emissions data and emission factors for shale gas well completions, a high priority within the EU is for the implementation of an extensive, managed programme of measurement and data analysis to develop a much more robust evidence base upon which to develop regulatory mechanisms and policy measures. In addition to advancing research to improve emission estimations from shale gas well sources, a greater focus is needed on ambient measurements around shale gas basins to assess the regional air quality impacts and conduct back-trajectory modelling verification of fugitive methane leaks from gas production facilities. There is only limited information on such studies in the U.S. and the verification of methane inventory estimates is typically problematic in the EU given a lack of long term trend data from ambient measurements; these systems require additional research and on-going support and would provide wider benefits than just for shale gas E&P research.

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9 Glossary

Glossary adapted in part from NYSDEC (2011). The majority of terms in this glossary are referred to in the report. Some additional terms are included to assist in wider discussion of unconventional gas operations.

Useful Terminology

Aquifer: A zone of permeable, water saturated rock material below the surface of the earth capable of producing significant quantities of water.

Annular Space or Annulus: Space between casing and the wellbore, or between the tubing and casing or wellbore, or between two strings of casing.

Anticline: A fold with strata sloping downward on both sides from a common crest.

Abandonment: To permanently close a well, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir. An abandoned well is plugged with cement to prevent the escape of methane to the surface or nearby aquifers.

Best Management Practice: Current state-of-the-art mitigation measures applied to oil and natural gas drilling and production to help ensure that development is conducted in an environmentally responsible manner. This is also known as Best Available Technique.

Blowout: An uncontrolled flow of gas, oil or water from a well, during drilling when high formation pressure is encountered.

Casing: Steel pipe placed in a well.

CO_{2eq}: Carbon dioxide equivalent, a measure used to compare the emissions from various greenhouse gases based upon their global warming potential. For example, the global warming potential for methane over 100 years is 21. This means that emissions of one million metric tons of methane is equivalent to emissions of 21 million metric tons of carbon dioxide.

Completion: the activities and methods of preparing a well for production after it has been drilled to the objective formation. This principally involves preparing the well to the required specifications; running in production tubing and its associated down hole tools, as well as perforating and stimulating the well by the use of hydraulic fracturing, as required.

Compressor Station: A facility which increases the pressure of natural gas to move it in pipelines or into storage.

Condensate: Liquid hydrocarbons that were originally in the reservoir gas and are recovered by surface separation.

Conventional reserve: a high permeability formation (greater than 1 milliDarcy) containing oil and / or gas, which can be more readily extracted than hydrocarbons from unconventional reserves

Dehydrator: A device used to remove water and water vapours from gas.

DIAL: Differential absorption light detection and ranging.

Directional drilling: Deviation of the borehole from vertical so that the borehole penetrates a productive formation in a manner parallel to the formation, although not necessarily horizontally.

Disposal Well: A well into which waste fluids can be injected deep underground for safe disposal.

Drilling Fluid: Mud, water, or air pumped down the drill string which acts as a lubricant for the bit and is used to carry rock cuttings back up the wellbore. It is also used for pressure control in the wellbore.

E&P: Exploration and Production.

Economically recoverable reserves: technically recoverable petroleum for which the costs of discovery, development, production, and transport, including a return to capital, can be recovered at a given market price.

Ecosystem: The system composed of interacting organisms and their environments.

EIS: Environmental Impact Statement.

Fault: A fracture or fracture zone along which there has been displacement of the sides relative to each other.

Field: The general area underlain by one or more pools.

Flash tank separator: As well as absorbing water from the wet gas stream, a glycol solution occasionally carries with it small amounts of methane and other compounds found in the wet gas. In order to recover this methane, a flash tank separator-condenser can be used to remove these compounds before the glycol solution reaches the boiler. The pressure of the glycol solution stream is reduced, allowing the methane and other hydrocarbons to vaporize ('flash') and be captured.

Flow back Fluids: Liquids produced following drilling and initial completion and clean-up of the well.

Fold: A bend in rock strata.

Footwall: The mass of rock beneath a fault plane.

Formation water: See Production water.

Formation: A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

Fossil methane / fossil fuel: A natural fuel such as coal or gas, formed in the geological past from the remains of living organisms.

Fracking or Fracing (pronounced “fracking”): informal abbreviation for "Hydraulic Fracturing".

Friction Reducer / Friction Reducing Agent: A chemical additive which alters the hydraulic fracturing fluid allowing it to be pumped into the target formation at a higher rate & reduced pressure.

Gas Metre: An instrument for measuring and indicating, or recording, the volume of natural gas that has passed through it.

Gas-Water Separator: A device used to separate undesirable water from gas produced from a well.

GEIS: Generic Environmental Impact Statement.

GHG: Greenhouse Gas.

GHGI: Greenhouse gas inventory.

GHGRP: Greenhouse gas reporting protocol.

Girdler Process: A widely used method for removal of hydrogen sulphide from natural gas by reacting the H_2S with amine compounds.

Glycol dehydration: a process in which a liquid desiccant dehydrator is used to absorb water vapour from the gas stream. A glycol solution, usually either diethylene glycol or triethylene glycol, is brought into contact with the wet gas stream. The glycol/water solution is put through a specialised boiler to vaporise the water, and enable glycol to be recovered for re-use.

GNBPA: Greater Natural Buttes Project Area.

GPS: Global positioning system.

Green Completion: see Reduced Emissions Completion.

Groundwater: Water in the subsurface below the water table. Groundwater is held in the pores of rocks, and can be connate (that is, trapped in the rocks at the time of formation), from meteorological sources, or associated with igneous intrusions.

GWP: Global warming potential. A measure of how much a given mass of greenhouse gas is estimated to contribute to global warming.

HAPS: Hazardous Air Pollutants as defined under the Clean Air Act (see http://www.epa.gov/ttn/atw/188polls.html).

High Volume Hydraulic Fracturing: The stimulation of a well (normally a shale gas well using horizontal drilling techniques with multiple fracturing stages) with high volumes of fracturing fluid. Defined by New York State DEC (2011) as fracturing using 300,000 gallons (1,350 m^3) or more of water as the base fluid in fracturing fluid.

Horizontal Drilling: Deviation of the borehole from vertical so that the borehole penetrates a productive formation with horizontally aligned strata, and runs approximately horizontally.

Horizontal Leg: The part of the wellbore that deviates significantly from the vertical; it may or may not be perfectly parallel with formational layering.

Hydraulic Fracturing Fluid: Fluid used to perform hydraulic fracturing; includes the primary carrier fluid, proppant material, and all applicable additives.

Hydraulic Fracturing: The act of pumping hydraulic fracturing fluid into a formation to increase its permeability.

Hydrocyclone: A device to classify, separate or sort particles in a liquid suspension based on the densities of the particles. A hydrocyclone may be used to separate solids from liquids or to separate liquids from different density.

Hydrogen Sulphide: A malodorous, toxic gas with the characteristic odour of rotten eggs.

Igneous Rock: Rock formed by solidification from a molten or partially molten state (magma).

Iron Inhibitors: Chemicals used to bind the metal ions and prevent a number of different types of problems that iron can cause (for example, scaling problems in pipe).

KML file: Computer file used in the Google Earth system.

LDAR: Leak detection and repair.

LEL: Lower explosive limit.

Limestone: A sedimentary rock consisting chiefly of calcium carbonate ($CaCO_3$).

Make-up water: water in which proppant and chemical additives are mixed to make fracturing fluids for use in hydraulic fracturing.

Manifold: An arrangement of piping or valves designed to control, distribute and often monitor fluid flow.

NAAQS: National Ambient Air Quality Standard.

NDIR: Non-Dispersive Infra-Red.

NESHAPs: National Emission Standards for Hazardous Air Pollutants.

NORM: Naturally Occurring Radioactive Materials. Low-level radioactivity that can exist naturally in native materials, like some shales, and may be present in drill cuttings and other wastes from a well.

Operator: Any person or organization in charge of the development of a lease or drilling and operation of a producing well.

Perforate: To make holes through the casing to allow the oil or gas to flow into the well or to squeeze cement behind the casing.

Perforation: A hole created in the casing to achieve efficient communication between the reservoir and the wellbore.

Permeability: A measure of a material’s ability to allow passage of gas or liquid through pores, fractures, or other openings. The unit of measurement is the Darcy or millidarcy.

Petroleum: In the broadest sense the term embraces the full spectrum of hydrocarbons (gaseous, liquid, and solid).

Pneumatic: Run by or using compressed air.

Polymer: Chemical compound of unusually high molecular weight composed of numerous repeated, linked molecular units.

Pool: An underground reservoir containing a common accumulation of oil and / or gas. Each zone of a structure which is completely separated from any other zone in the same structure is a pool.

Porosity: Volume of pore space expressed as a percent of the total bulk volume of the rock.

Primary Carrier Fluid: The base fluid, such as water, into which additives are mixed to form the hydraulic fracturing fluid which transports proppant.

Primary Production: Production of a reservoir by natural energy in the reservoir.

Product: A hydraulic fracturing fluid additive that is manufactured using precise amounts of specific chemical constituents and is assigned a commercial name under which the substance is sold or utilized.

Production Casing: Casing set above or through the producing zone through which the well produces.

Production water: Liquids co-produced during oil and gas wells production.

Proppant or Propping Agent: A granular substance (sand grains, aluminium pellets, or other material) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.

Proved reserves: The quantity of energy sources estimated with reasonable certainty, from the analysis of geologic and engineering data, to be recoverable from well established or known reservoirs with the existing equipment and under the existing operating conditions.

PRTR: Pollutant Release and Transfer Register.

REC: Reduced Emissions Completion.

Reduced Emissions Completion (also known as green completion): a term used to describe a practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the high-rate flow back, and produce gas that can be delivered into the sales pipeline. RECs help to reduce methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

Reservoir (oil or gas): A subsurface, porous, permeable or naturally fractured rock body in which oil or gas has accumulated. A gas reservoir consists only of gas plus fresh water that condenses from the flow stream reservoir. In a gas condensate reservoir, the hydrocarbons may exist as a gas, but, when brought to the surface, some of the heavier hydrocarbons condense and become a liquid.

Reservoir Rock: A rock that may contain oil or gas in appreciable quantity and through which petroleum may migrate.

Sandstone: A variously coloured sedimentary rock composed chiefly of sand like quartz grains cemented by lime, silica or other materials.

Scale Inhibitor: A chemical substance which prevents the accumulation of a mineral deposit (for example, calcium carbonate) that precipitates out of water and adheres to the inside of pipes, heaters, and other equipment.

Sedimentary rock: A rock formed from sediment transported from its source and deposited in water or by precipitation from solution or from secretions of organisms.

SEIS: Supplemental Environmental Impact Statement.

Seismic: Related to earth vibrations produced naturally or artificially.

Separator: Tank used to physically separate the oil, gas, and water produced simultaneously from a well.

SGEIS: Supplemental Generic Environmental Impact Statement.

Shale gas: Shale Gas is natural gas that is formed from being trapped within shale (fine grained sedimentary rock) formations.

Shale oil: Oil shale, also known as kerogen shale, is an organic-rich fine-grained sedimentary rock containing kerogen (a solid mixture of organic chemical compounds) from which liquid hydrocarbons called shale oil can be produced. Crude oil which occurs naturally in shales is referred to as "tight oil".

Shale: A sedimentary rock consisting of thinly laminated claystone, siltstone or mud stone. Shale is formed from deposits of mud, silt, clay, and organic matter.

Show: Small quantity of oil or gas, not enough for commercial production.

Siltstone: Rock in which the constituent particles are predominantly silt size.

Slickwater Fracturing (or slick-water): A type of hydraulic fracturing which utilizes water-based fracturing fluid mixed with a friction reducing agent and other chemical additives.

Spudding: The breaking of the earth's surface in the initial stage of drilling a well.

Squeeze: Technique where cement is forced under pressure into the annular space between casing and the wellbore, between two strings of pipe, or into the casing-hole annulus.

Stage Plug: A device used to mechanically isolate a specific interval of the wellbore and the formation for the purpose of maintaining sufficient fracturing pressure.

Stage: Isolation of a specific interval of the wellbore and the associated interval of the formation for the purpose of maintaining sufficient fracturing pressure.

Stimulation: The act of increasing a well's productivity by artificial means such as hydraulic fracturing or acidizing.

Stratum (plural strata): Sedimentary rock layer typically referred to as a formation, member, or bed.

Surface Casing: Casing extending from the surface through the potable fresh water zone.

Surfactants: Chemical additives that reduce surface tension; or a surface active substance. Detergent added to hydraulic fracturing fluid is a surfactant.

Target Formation: The reservoir that the driller is trying to reach when drilling the well.

Technically recoverable reserves: The proportion of assessed in-place petroleum that may be recoverable using current recovery technology, without regard to cost.

Tight Formation: Formation with very low (less than 1 milliDarcy) permeability.

Tight gas: Natural gas obtained from a tight formation.

UIC: Underground Injection Control.

Unconventional gas: Gas contained in rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 1 millidarcy.

USDW - Underground Source of Drinking Water: An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/L total dissolved solids and is not an exempted aquifer.

Vapour Recovery Unit: A system to which gases from gas collection and processing operations are charged to separate the mixed gases for further processing. The vapours are sucked through a scrubber, where the liquid trapped is returned to the liquid pipeline system or to the tanks, and the vapour recovered is pumped into gas lines.

Viscosity: A measure of the degree to which a fluid resists flow under an applied force.

VOC: Volatile Organic Compound.

VRU: Vapour Recovery Unit.

Water Well: Any residential well used to supply potable water.

Watershed: The region drained by, or contributing water to, a stream, lake, or other body of water.

Well pad: A site constructed, prepared, levelled and / or cleared in order to perform the activities and stage the equipment and other infrastructure necessary to drill one or more natural gas exploratory or production wells.

Well Pad: The area directly disturbed during drilling and operation of a gas well.

Well site: Includes the well pad and access roads, equipment storage and staging areas, vehicle turnarounds, and any other areas directly or indirectly impacted by activities involving a well.

Wellbore: A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open.

Wellhead: The equipment installed at the surface of the wellbore. A wellhead includes such equipment as the casing head and tubing head.

Wildcat: Well drilled to discover a previously unknown oil or gas pool or a well drilled one mile or more from a producing well.

Workover: Repair operations on a producing well to restore or increase production. This may involve repeat hydraulic fracturing to re-stimulate gas flow from the well.

Zone: A rock stratum of different character or fluid content from other strata.

Relevant Organisations

AERMOD: AMS/EPA Regulatory MODel.

ANGA: America's Natural Gas Alliance.

API: American Petroleum Institute.

AXPC: American Exploration and Production Council.

BCOGC: British Columbia Oil and Gas Commission.

BLM: United States Federal Bureau of Land Management.

CFR: Code of Federal Regulations.

CGA: Canadian Gas Association.

EPA: The (U.S.) Environmental Protection Agency.

KMG: Kerr-McGee Oil & Gas Onshore LP.

NYSDEC: New York State Department of Environmental Conservation.

TCEQ: Texas Commission on Environmental Quality.

U.S. EPA: United States Environmental Protection Agency.

U. S. GS: United States Geological Survey.

Common Units

Barrel: A volumetric unit of measurement equivalent to 42 U.S. gallons or 0.159 $m^{3.}$

bbl/yr: Barrels per year.

bbl: Barrel.

Bcf: Billion cubic feet. A unit of measurement for large volumes of gas. 1 bcf is equivalent to 28.3 million cubic metres.

Darcy: A unit of permeability. A medium with a permeability of 1 darcy permits a flow of 1 cm^3/s of a fluid with viscosity 1 cP (1 mPa·s) under a pressure gradient of 1 atm/cm acting across an area of 1 cm^2.

gpd: Gallons per day.

gpm: Gallons per minute.

Mcf: Thousand cubic feet (equivalent to 28.3 cubic metres).

md: Millidarcy.

MDL: Minimum Detection Limit.

Methane: Methane (CH_4) is a greenhouse gas that remains in the atmosphere for approximately 9-15 years. Methane is also a primary constituent of natural gas and an important energy source.

Millidarcy: A unit of permeability, equivalent to one thousandth of a Darcy.

ppb: Parts per billion.

ppm: Parts per million.

Tcf: Trillion cubic feet, equivalent to 28.3 billion cubic metres.

tpy: Tonnes per year.

Chemistry / biology

Bactericides: Also known as a "Biocide." An additive that kills bacteria.

Biocides: See "Bactericides".

Breaker: A chemical used to reduce the viscosity of a fluid (break it down) after the thickened fluid has finished the job it was designed for.

BTEX: Benzene, Toluene, Ethylbenzene, and Xylene. These are all aromatic hydrocarbons.

Buffer agent: A weak acid or base used to maintain the pH of a solution at or close to a chosen value.

CAS Number: Chemicals Abstract Service number, assigned by Chemical Abstracts Service.

CBM: Coal bed methane.

CEAS: Cavity enhanced adsorption spectroscopy.

CFR: Code of Federal Regulations.

CGA: Canadian Gas Association.

CH_4: Chemical formula of methane.

Chemical Additive: A product composed of one or more chemical constituents that is added to a primary carrier fluid to modify its properties in order to form hydraulic fracturing fluid.

Chemical Constituent: A discrete chemical with its own specific name or identity, such as a CAS Number, which is contained within an additive product.

CO: Chemical formula of carbon monoxide.

CO_2: Chemical formula of carbon dioxide.

Coal bed methane: A form of natural gas extracted from coal beds. The term refers to methane adsorbed onto the solid matrix of the coal.

Gelling Agents: Polymers used to thicken fluid so that it can carry a significant amount of proppants into the formation.

Corrosion Inhibitor: A chemical substance that minimizes or prevents corrosion in metal equipment.

H_2O: chemical formula for water.

H_2S: Chemical formula for hydrogen sulphide.

NO_x: Abbreviation for “oxides of nitrogen” made up primarily of nitrogen dioxide (NO_2) and nitric oxide (NO).

NSPS Regulations: New Source Performance Standard Regulations.

O_2: Chemical formula for oxygen.

O_3: Chemical formula for ozone.

NH_3: Chemical formula for ammonia.

SO_2: Chemical formula for sulphur dioxide.

Appendices

Appendix 1: Literature for GHG emissions from shale gas production

Appendix 2: Knowledge review for reporting frameworks

Appendix 1: Literature for GHG emissions from shale gas production

This appendix describes in more detail the studies that have been examined as part of the literature review of existing studies on the GHG emissions from shale gas production. The results from these studies were described in Chapter 3. In order to compare the studies on an equal basis, the results, as presented in the original studies, have been converted into consistent units. The main studies, and the associated conversions, are described briefly below.

Stephenson et al (2011)

Results are presented and described by process stage, and for a range of scenarios. The results are presented as well to wire emissions in grams of CO_2 equivalents per kWh of electricity production. The estimates are modelled at an aggregated level, and represent the shale gas sector as a whole rather than a specific site or location. However, certain site data is used as the basis of the modelling calculations. Estimates are made of the diesel use during drilling/hydraulic fracturing and during transport in m^3 per well. These were converted into tonnes of CO_2 equivalents on the basis of emission factor for diesel consumption reported in the paper (250 gCO_2/kWh). The assumed methane emissions from well completions are reported in tonnes of methane per well, and were based on the factors reported in EPA (2011).

Jiang et al (2011)

Results are presented in the main paper, with additional information in the supplementary information document. The results are presented and described by process stage. Estimates are provided for well pad preparation, well drilling, hydraulic fracturing and well completion.

In the main paper the results are presented as gCO_2eq/MJ. In the supporting information, estimates are also provided in tonnes of CO_2eq per well, as well as gCO_2eq/MJ natural gas. Estimates are provided for an illustrative well pad on the Marcellus shale. Table 9 of the supplementary information document summarises the GHG emissions by process stage in terms of the metric tonnes of CO_2 e.g. per well. However, not all of the values reported in the table are consistent with the analysis presented elsewhere in the supplementary information document. The ranges described in the text of the supplementary information document were therefore assumed to supersede those in the summary table. For emissions from well completion the methane releases reported in Section 4 of the main paper were used.

Santaro et al (2011)

Results are presented for Marcellus shale as a case study. Emissions are estimated by activity, and include land clearing, resource consumption, and diesel consumed in internal-combustion engines (mobile and stationary) during well development. Energy consumed once the gas well is brought into production (i.e. that consumed in production, processing, and transmission/distribution streams) are assumed to be similar to previously published estimates; therefore, emission intensities from the literature are used for these sources. Excluded from the analysis are emissions from venting and flaring of emissions.

Table 3 of the technical report presents the results by activity, with the primary calculations and assumptions presented elsewhere in the report. The results are presented in grams of carbon per MJ of natural gas (g C MJ-1), and for both a Low Heating Value (LHV) and High Heating Value (HHV) for the gas. These values were converted into an estimate of the emissions per well (g C) based on the lifetime wellhead production, accounting for losses (with processing), quoted in the technical report for a representative Marcellus shale gas well. This production data is provided in Table 2.3 of the technical report.

Broderick et al (2011)

Emissions are estimated for each of the stages in the extraction. The estimates are based on data associated with the extraction at the Marcellus Shale in the U.S. This includes drilling, fracturing, energy production, chemical production, water transportation and wastewater treatment. The results are presented per well in tonnes of CO_2 for a single fracturing process. The results represent the additional emissions over and above conventional gas extraction approaches. These results have been used directly in the current study, without any further conversion required.

For well completion, Broderick et al used estimates of the volume of methane released from studies by Jiang et al (2011), Howarth et al (2011), Skone et al (2011) and EPA (2010).

Skone et al (2011)

Estimated emissions were based upon modelling of the full lifecycle impacts from cradle to gate. Results were presented as lbs CO_2eq per MMBtu. For well completions the estimated emissions draw upon the values reported in EPA (2011). However, there is apparent misinterpretation of the emissions factor (where the factor is assumed to represent million cubic feet of methane, rather than natural gas) which leads to slight overestimate of the emissions compared to the original EPA (2011) study.

Lechtenbohmer (2011)

The emissions reported in this study are essentially based on the estimates presented in Santaro et al (2011) and Howarth et al (2011). However, an adjustment has been made to the emissions associated with well completions to allow for a greater proportion of flaring than in the original Howarth study. This explains the lower emissions for this stage in the cycle than those reported in the original study.

Howarth et al (2011)

The report focusses on fugitive methane emissions. It includes emissions from the well completion stage, routing venting and equipment leaks, processing and the transportation and distribution. The results are presented as a percentage of the total production of the well. The results from the well completion stage have been converted into absolute emissions on the basis of the gas release rates reported in table 1 of the report. The methane content of the gas was assumed to be 78.8%, as reported in EPA (2011).

U.S. EPA (2012)

This is a guidance document for the oil and gas industry reporting to the GHG Reporting Protocol, a new mandatory reporting system in the U.S., which outlines the range of information from industry sources across the U.S. The recommended U.S. EPA default emission factor for emissions of gas for unconventional gas wells. The U.S. EPA recommended emission factors for well completion have been subject to significant industry scrutiny and some criticism. The U.S. EPA has responded by publishing a document to outline the various industry data sources, assumptions and options for deriving emission factors.

NYSDEC (2011)

This document, published by the New York State Department of Environmental Conservation (NYSDEC) is the most recent draft Supplementary Guidance for Environmental Impact Statement for Horizontal drilling and hydraulic fracturing operations. This has been produced following extensive consultation and public review. It provides an extensive review of the available evidence for potential environmental impacts including GHG emissions

Appendix 2 – Knowledge review for reporting frameworks

This annex provides a summary of the main details on fugitive methane emission sources, estimation methods, emission factors and protocols that the study team has identified to date. The annex covers:

A2.1. Information from technical guidance documents used by the oil & gas industry for estimating and reporting fugitive releases from unconventional gas E&P sources, including the equations and emission factors that are available to oil and gas industry operators in their submission of estimates of emissions to regulators;

A2.2. Information from National Inventory Reports, summarising the approach by inventory agencies in compiling and reporting national estimates of fugitive methane emissions from conventional and unconventional gas exploration and production (E&P) sources;

A2.3. IPCC guidance for national GHG inventories.

All of these resources are potentially useful in the derivation of future EU Member State national inventories that are detailed and accurate in their fugitive methane emission estimates from shale gas activities; the industry in Europe will need to adopt some level of consistency in operator-level / installation-level measurement, estimation, compilation and reporting of fugitive releases, for the national inventory agencies to have data of sufficient quality to report to the EUMM.

A2.1 OIL & GAS INDUSTRY EMISSION ESTIMATION GUIDANCE

This section includes a summary of information from the following sources:

- U.S. EPA 40 CFR Part 98: GHGRP for GHG reporting for Natural gas systems;
- API Compendium on GHG emission estimation methods for the oil & gas industry;
- U.S. EPA voluntary reporting programme for oil and gas emission mitigation, Natural Gas STAR;
- The UK reporting guidance to offshore oil & gas operators, for the EEMS reporting system.

A2.1.1 U.S. EPA 40 CFR Part 98: GHGRP for GHG reporting for Natural gas systems

This reference source from December 2011 is the final set of GHG estimation and reporting protocols that have been established by the U.S. EPA for operators of oil and gas installations to use under the new mandatory GHG reporting system for installations over a certain threshold emissions level in the U.S. The document has gone through several iterations during 2011 with periodic consultation with the industry and has had many improvements through review by leading industry experts. The emission factors quoted in the U.S. EPA guidance are quite uncertain and subject to on-going challenges from the industry and other stakeholders. However, in researching available protocols that could provide the basis for future EU reporting guidance, the U.S. EPA GHGRP provides a detailed description of estimation methods, equations and insight into the level of granularity of data required to be reported by U.S. gas operators.

The document provides estimation method options for:

- Gas venting emissions during unconventional gas completions and work-overs where the backflow rate is measured or calculated (Equation W-10A);
- Gas venting emissions during unconventional gas completions and work-overs where the backflow vent or flare volume is measured (Equation W-10B).

The information below is a transcript of the relevant section of the U.S. EPA's latest guidance to oil and gas operators, providing emission estimation methods and emission factors, including for unconventional gas exploration and production.

Source: U.S. EPA (December 2011), "GREENHOUSE GAS EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUSTRY BACKGROUND TECHNICAL SUPPORT DOCUMENT", Part 98.233(g).

"Gas well venting during completions and work overs from hydraulic fracturing".

Calculate CH_4, CO_2 and N_2O annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well work overs using Equation W-10A or Equation W-10B of this section. Equation W-10A applies to well venting when the backflow rate is measured or calculated, Equation W-10B applies when the backflow vent or flare volume is measured. Use Equation W-10A if the flow rate for backflow during well completions and work overs from hydraulic fracturing is known for the specified number of wells per paragraph (g) (1) in a sub-basin and well type (horizontal or vertical) combination. Use Equation W-10B if the flow volume for backflow during well completions and work overs from hydraulic fracturing is known for all wells in a sub-basin and well type (horizontal or vertical) combination. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_p \times FRM \times PR_p - EnF_p - SG_p \right] \qquad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_p - EnF_p \right] \qquad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions or work overs following hydraulic fracturing for each sub-basin and well type (horizontal vs. vertical) combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type (horizontal vs. vertical) combination.

T_p = Cumulative amount of time of backflow for the completion or work over, in hours, for each well, p, in a sub-basin and well type (horizontal vs. vertical) combination during the reporting year.

FRM = Ratio of backflow during well completions and work overs from hydraulic fracturing to 30-day production rate from Equation W-12.

PR_p = First 30-day average production flow rate in standard cubic feet per hour of each well p, under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.

EnF_p = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job for each well p. If the fracture process did not inject gas into the reservoir, then EnF_p is 0. If injected gas is CO_2 then EnF_p is 0.

SG_p = Volume of natural gas in cubic feet at standard conditions that was recovered into a flow-line for well p as per paragraph (g) (3) of this section. This parametre includes any natural gas that is injected into the well for clean-up. If no gas was recovered, SG_p is 0.

FV_p = Flow volume of each well (p) in standard cubic feet per hour measured using a recording flow metre (digital or analog) on the vent line to measure backflow during the completion or work over according to methods set forth in §98.234(b).

(1) The average flow rate for backflow during well completions and work overs from hydraulic fracturing shall be determined using measurement(s) for calculation methodology 1 or calculation(s) for calculation methodology 2 described in this paragraph (g)(1) of this section. If Equation W-10A is used, the number of measurements or calculations shall be determined per sub-basin and well type (horizontal or vertical) as follows: one measurement or calculation for less than or equal to 25 completions or work overs; two measurements or calculations for 26 to 50 completions or work overs; three measurements or calculations for 51 to 100 completions or work overs; four measurements or calculations for 101 to 250 completions or work overs; and five measurements or calculations for greater than 250 completions or work overs.

(i) Calculation Methodology 1. When using Equation W-10A, for each measured well completion(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination and for each measured well work over(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination, a recording flow metre (digital or analog) shall be installed on the vent line, ahead of a flare or vent if used, to measure the backflow rate according to methods set forth in §98.234(b).

(ii) Calculation Methodology 2. When using Equation W-10A, for each calculated horizontal well completion and each calculated vertical well completion in each gas producing sub-basin category and for each calculated well horizontal work over and for each calculated vertical well work over in each gas producing sub-basin category, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in §98.234(b) to calculate the well backflow during well completions and work overs from hydraulic fracturing. Calculate emissions using Equation W-11A of this section for subsonic flow or Equation W-11B of this section for sonic flow. Use best engineering estimate based on best available data along with Equation W-11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W-11C is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic:

$$FR = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \quad \text{(Eq. W-11A)}$$

Where:

FR	=	*Average flow rate in cubic feet per hour, under subsonic flow conditions.*
A	=	*Cross sectional area of orifice (m^2).*
P_1	=	*Upstream pressure (psia).*
T_u	=	*Upstream temperature (degrees Kelvin).*
P_2	=	*Downstream pressure (psia).*
3430	=	*Constant with units of $m^2/(sec^2 * K)$.*
$1.27*10^5$	=	*Conversion from m^3/second to ft^3/hour.*

$$FR = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \quad \text{(Eq. W-11B)}$$

Where:

FR	=	*Average flow rate in cubic feet per hour, under sonic flow conditions.*
A	=	*Cross sectional area of orifice (m^2).*
T_u	=	*Upstream temperature (degrees Kelvin).*
187.08	=	*Constant with units of $m^2/(sec^2 * K)$.*
$1.27*10^5$	=	*Conversion from m^3/second to ft^3/hour.*

$$R = P1/P2 \quad \text{(Eq. W-11C)}$$

Where:

R	=	*Pressure ratio*
P1	=	*Pressure upstream of the restriction orifice in pounds per square inch absolute.*
P2	=	*Pressure downstream of the restriction orifice in pounds per square inch absolute.*

(iii) For Equation W-10A, the ratio of backflow rate during well completions and work overs from hydraulic fracturing to 30-day production rate is calculated using Equation W-12 of this section.

$$FRM = \frac{\sum_{p=1}^{W} FR_p}{\sum_{p=1}^{W} PR_p} \qquad \text{(Eq. W-12)}$$

Where:

FRM = Ratio of backflow rate during well completions and work overs from hydraulic fracturing to 30-day production rate.

FR_p = Measured backflow rate from Calculation Methodology 1 or calculated flow rate from Calculation Methodology 2 in standard cubic feet per hour for well(s) p for each sub-basin and well type (horizontal or vertical) combination. You may not use flow volume as used in Equation W-10B converted to a flow rate for this parametre.

PR_p = First 30-day production rate in standard cubic feet per hour for each well p that was measured in the sub-basin and well type combination.

W = Number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type formation.

(iv) For Equation W-10A, the ratio of backflow rate during well completions and work overs from hydraulic fracturing to 30-day production rate for horizontal and vertical wells are applied to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well work overs, respectively, in the gas producing sub-basin and well type combination for the total number of hours of backflow for each of these wells.

(v) For Equation W-10A, new flow rates for horizontal and vertical gas well completions and horizontal and vertical gas well work overs in each sub-basin category shall be calculated once every two years starting in the first calendar year of data collection.

(2) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate metre as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii)[Reserved]

(3) Determine if the backflow gas from the well completion or work over from hydraulic fracturing is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line (e.g., reduced emissions completion or work overs).

(i) Use the factor SG_P in Equation W-10A of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g) (4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the backflow as determined by engineering estimate based on best available data.

(ii) [Reserved]

(iii) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate annual emissions from gas well venting during well completions and work overs from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and work overs as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and work overs using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH_4 to CO_2 in the flare.

Later on in the U.S. EPA GHG Reporting Protocol guidance document, the emission factors recommended for use by gas operators in the estimation of emissions from well completions and work-overs are described. These factors are uncertain and subject to on-going challenges by the industry and other stakeholders (see report Section 3.3.6.2 for more details). The description of the derivation of emission factors is reproduced below.

Estimate the Emission Factor for Unconventional Well Completions

The emission factor for unconventional well completions was derived using several experiences presented at Natural Gas STAR technology transfer workshops.

One presentation reported that the emissions from all unconventional well completions were approximately 45 Bcf using 2002 data. The emission rate per completion can be back-calculated using 2002 activity data. API Basic Petroleum Handbook lists that there were 25,520 wells completed in 2002. Assuming Illinois, Indiana, Kansas, Kentucky, Michigan, Missouri, Nebraska, New York, Ohio, Pennsylvania, Virginia, and West Virginia produced from low-pressure wells that year, 17,769 of those wells can be attributed to onshore, non-low-pressure formations. The Handbook also estimated that 73% (or 12,971 of the 17,769 drilled wells) were gas wells, but are still from regions that are not entirely low-pressure formations. The analysis assumed that 60% of those wells are high pressure, tight formations (and 40% were low-pressure wells). Therefore, by applying the inventory emission factor for low-pressure well clean-ups (49,570 scf/well-year11) approximately 5,188 low-pressure wells emitted 0.3 Bcf.

$$40\% \times 12{,}971 \text{ wells} \times 49{,}570 \text{ scf/well} \times (1 \text{ bcf} / 109 \text{ scf}) \approx 0.3 \text{ Bcf}$$

The remaining high pressure, tight-formation wells emitted 45 Bcf less the low-pressure 0.3 Bcf, which equals 44.7 Bcf. Since there is great variability in the natural gas sector and the resulting emission rates have high uncertainty; the emission rate per unconventional (high-pressure tight formation) wells were rounded to the nearest thousand Mcf.

$$(44.7 \text{ bcf} / 60\% \times 12{,}971 \text{ wells}) \times (106 \text{ Mcf} / 1 \text{ Bcf}) \approx 6{,}000 \text{ Mcf/completion}$$

The same Natural Gas STAR presentation provides a Partner experience which shares its recovered volume of methane per well. This analysis assumes that the Partner recovers 90% of the flow back. Again, because of the high variability and uncertainty associated with different completion flow backs in the gas industry, this was estimated only to the nearest thousand Mcf – 10,000 Mcf/completion.

A vendor / service provider of "reduced emission completions" shared its experience later in that same presentation for the total recovered volume of gas for 3 completions. Assuming that 90% of the gas was recovered, the total otherwise-emitted gas was back-calculated. Again, because of the high variability and uncertainty associated with different completion flow backs in the gas industry, this was rounded to the nearest hundred Mcf – 700 Mcf/completion.

The final Natural Gas STAR presentation with adequate data to determine an average emission rate also presented the total flow back and total completions and re-completions. Because of the high variability and uncertainty associated with different completion flow backs in the gas industry, this was rounded to the nearest 10,000 Mcf – 20,000 Mcf/completion.

This analysis takes the simple average of these completion flow backs for the unconventional well completion emission factor: 9,175 Mcf/completion.

► *Estimate the Emission Factor for Unconventional Well Work overs ("re-completions")*
The emission factor for unconventional well work overs involving hydraulic re-fracture ("re-completions") was assumed to be the same as unconventional well completions; calculated in the previous section."

Prior to the finalisation of the U.S. EPA GHG Reporting Protocol sector guidance for gas operators, a process of industry consultation was conducted, and the U.S. EPA (2012) published a document that summarised the industry feedback that led to technical revisions in the final version of the rule.

This document includes feedback from the API and other industry expert groups on the proposed GHGRP for mandatory operator reporting to the U.S. EPA, and includes useful insights into some of the difficulties in formulating emission estimation equations and factors for unconventional gas well completions. The sections below are transcripts from that Technical Review document.

Section 7.10 Gas Well Venting During Completions and Workovers from Hydraulic Fracturing.

"API appreciates the clarity provided by documenting the equation determining if the flow rate is sonic or sub-sonic. However, Methodology 2 does not acknowledge that a single completion or workover can alternate between sonic and sub-sonic flows. As API pointed out in a letter to EPA on May 13, 2011, flow back on any single completion will be partially supersonic and partially subsonic. Reporters cannot discern exactly when flow back falls into either category during a completion. Additionally, liquids and gases flow at different rates. As a completion progresses, the amount of liquids decreases and the amount of gases increases". (K Ritter, API).

Data reporting requirements: EPA clarified that the total count of workovers in the calendar year should be reported for those that flare gas or vent to the atmosphere.

7.11 Gas Well Venting During Completions and Workovers without Hydraulic Fracturing

EPA has revised the emission factor for non-hydraulic fracture well workover venting from 2,454 scf CH4/workover to 3,114 scf gas/workover. Comment: API has reviewed this correction and confirmed that EPA is adjusting the emission factor of 2,454 scf CH4/workover to a natural gas basis, based on 78.8 mol% CH4. This conversion does result in 3,114 scf natural gas/workover, as shown below, where standard conditions are 60 ºF and 14.7 psia.

A2.1.2 American Petroleum Institute Compendium of GHG Emission Methodologies for the Oil and Natural Gas Industry, August 2009

The API compendium is widely used by the oil and gas sector as the primary source of information on emission estimation methods for releases from oil and gas operations. Within many of the regulatory guidance notes and operator reporting systems evident within the EU, references to API methods for many sources are widespread. The compendium provides the basis for many of the emission estimation methods for sources from unconventional gas E&P sources. The compendium includes a section specifically on approaches to estimating emissions from well completions, which references the options for mitigation, and summarises activities such as well work overs. The references in the 2009 compendium for these sources are acknowledged as being somewhat dated and based on a limited dataset. (Note that this information on well completions does not specifically mention unconventional well completions, however).

Table 5-23, on page 5-91 provides onshore gas well completion factors of 1,712,000 scf/completion-day, which in mass terms is cited as 25.9 tonnes/completion day.

Section 5.7.2 Production Related Non-Routine Emissions

Well work overs refer to activities performed to restore or increase production. Work over activities involve pulling the tubing from the well to repair tubing corrosion or other down-hole equipment problems. If the well has positive pressure at the surface, the well is "killed" by replacing the gas and oil in the column with a heavier fluid, such as mud or water, to stop the flow of oil and natural gas. A small amount of gas is released as the tubing is removed from the open surface casing. Derivation of the GRI / EPA emission factors for well work overs was based on data from a limited number of production fields collected by Pipeline Systems Incorporated (PSI, 1990). Well completions are associated with the final step of the well drilling. After a well is drilled, the well bore and reservoir near the well have to be cleaned. This is accomplished by producing the well to pits or tanks where sand, cuttings, and other reservoir fluids are collected for disposal. This step is also useful to evaluate the well production rate to properly size the production equipment. The vented gas well completion CH4 emission factors were derived based on the initial rates of production in 2000 (EIA, 2001). Actual data on the volume of gas vented due to completion activities would provide a more rigorous emission estimate. The emission factors from Table 5-23 may be used when producing the wells to pits or tanks *after the completion, in the absence of such data. The natural gas from the completion process can either be vented to the atmosphere or flared.*

A method known as "green completions" may be utilized where the well completion gas is captured by temporary equipment brought to the site to clean up the gas to the point that it can be sent to the sales line, thus avoiding vented emissions. If green completion methods are used to recover any of the well completion emissions, the uncontrolled (vented) CH_4 emission factor must be multiplied by the non-recovered fraction associated with the green completion method. The percentage recovery via green completions should be based on site-specific data.

A2.1.3 U.S. EPA Programme: Natural Gas STAR

The U.S. EPA's Natural Gas STAR programme is a voluntary industry reporting programme for the dissemination of information pertaining to GHG mitigation in the oil and gas sector. The programme documents contain data that relate to unconventional gas E&P fugitive methane emissions and the approaches to minimise these releases; the data are provided by the industry and are NOT verified by the U.S. EPA or state-level regulators and therefore the data are provided here for indicative purposes only.

http://www.epa.gov/gasstar/tools/recommended.html

The publications available on the Gas STAR website provide information on a range of mitigation options for emissions sources from the oil and gas industry, some of which are applicable to unconventional gas E&P sources, including:

- Compressors / Engines;
- Deydrators;
- Directed Inspection and Maintenance;
- Pipelines;
- Pneumatics / Controls;
- Tanks;
- Valves;
- Wells.

A number of these options will be directly applicable to the mitigation of fugitive methane emissions from unconventional gas E&P:

- **Install Flares**: $10,000-$50,000
  http://www.epa.gov/gasstar/documents/installflares.pdf
  The applicability of installing flares to unconventional gas E&P systems is limited due to the variable pressure of the initial well venting / flow back phase which is the period in which the largest fugitive emissions are produced.
- **Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells:** *>$50,000* http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf
  The technology involves installation of sand trap and fluid separator systems to capture flow back fluid and entrained methane (and other) gas, and separate the water, condensate and recover the gas which may be recoverable via a dehydrator to the sales line. Overall the installation costs are estimated at around $620,000, and payback is estimated at 3-6 months using various scenarios for gas price.

It is recommended that the EU considers more detailed research into the fugitive methane emissions and mitigation options for shale gas E&P. Any such research should include a system of independent data checking to validate the information from industry, reduce data uncertainties and ensure that study outputs are at a level of detail commensurate with the requirements for GHG data reporting by emission source.

A2.1.4 UK Guidance to Offshore Operators: EEMS Atmospheric Emissions Calculations (UK Oil & Gas and DECC, 2008)

The EEMS guidance provides methodological information on emission estimation options, providing default emission factors for some sources, and outlining methods for operators to use fuel compositional analysis to derive source-specific emission factors:

"Most operators have compositional analyses for fuel gas, it is less commonly available for flare and vent gas. Compositions are given in the form of component mole percentages (Cmol) from analysis by gas chromatography. Component mole percentages can be used to calculate emission factors for directly vented or fugitive and certain combustion emissions. For direct emission sources the component weight percentages (Cwt) lead directly to the emission gas factors."

The guidance includes a section on Scientific Background, outlining the Ideal Gas Law, mole, Absolute Temperature, Atomic and molecular weights, and then a section on reporting to standard conditions:

"Mass is the preferred physical quantity for reporting gas emissions because of its independence of temperature and pressure. All gas amounts reported to EEMS are masses, usually in tonnes (t). However, most gas measurements made in the field are volumes at non-standard temperatures and pressures. Commonly used in the oil and gas industry are the API standard conditions, which differ from the European definition of 'standard'. The following guidelines should be used when converting non-standard volumes to reported masses…"

The guidance note provides example calculations for operators to use to convert emission estimates to a mass basis (p16-19).

Emission calculations and factors are provided for combustion, direct emissions (venting, loading / unloading) and fugitives, advocating the use of source-specific gas compositional data where available. The estimation method for fugitive releases only covers the fugitives from component leaks. The method is outlined thus: "*component numbers including joints, valves and pumps, and the application of a fugitive emission factor for each category of component. This gives a total emission figure, and the gas composition is used to calculate individual components".*

Calculations are presented for each type of source, p23-46, including venting on p37, fugitive on p41. These could form the basis for future onshore gas operator guidance, although they do not cover the sources specific to shale gas E&P such as fugitive emissions from unconventional well completions.

The EEMS General Guidance Note gives a useful overview of reporting requirements, outlining the scope of supplementary information (i.e. as well as emissions data) that operators must provide as part of the site regulatory regime, see:

http://og.decc.gov.uk/en/olgs/cms/environment/eems/technical_docs/technical_docs.aspx

A2.2 INFORMATION FROM NATIONAL INVENTORY REPORTS

This section summarises information from National Inventory Reports, including:

- U.S. NIR 1990-2009;
- Canada NIR 1990-2009;
- Germany NIR 1990-2009;
- Poland NIR 1990-2009.

A2.2.1 Information from the U.S. NIR, 1990-2009

U.S. National Inventory Report Appendix 3, Section 3.4 includes emission factors for the calculation of emissions from unconventional gas wells. There are a large number of detailed factors provided for leakages from specific components (heaters, separators, dehydrators, metremetres, piping, compressors etc.), as well as from sources such as flaring, and also specific periodic activities such as drilling, well completions, well work-overs and well clean-ups.

Regional factors are provided to cover different typical gas compositions from fields across the U.S. but typical examples of factors for activities specific to unconventional gas E&P include:

Source	U.S. NIR factor (Table A-120)	tonnes methane	Tonnes CO_2eq
Gas well completion flaring	21.84 m^3 of gas / completion[43]	0.01 per completion	0.25 per completion
Unconventional gas well completion (*no mitigation*)	~215,600 m^3 of gas / completion	~117 per completion	~2,925 per completion
Unconventional gas well work-over (*no mitigation*)	~215,600 m^3 of gas / completion	~117 per completion	~2,925 per completion
Gas well drilling	75.6 m^3 of gas / well	0.04 per well	1 per well
Gas well clean-ups (LP wells)	~39,200 m^3 of gas / well	~21 per well	525 per well

**Conversion to mass basis assumes 78.8% mole fraction of methane in gas.*

The emission factors presented in the U.S. NIR are based on a detailed industry study using data from 1992 (EPA/GRI 1996), with some factors updated by later studies such as:

- Gas well clean-ups (EPA 2006, HDPI 2009);
- Condensate storage tanks (EPA 1999, HPDI 2009, TERC 2009);
- Centrifugal compressors (EPA 2006b, WGC 2009);
- Gas well completions and work overs (re-completions) with hydraulic fracturing (i.e. unconventional) (EPA 2004, 2007).

The U.S. NIR includes an overview of how the emission estimates are compiled based on regional gas compositional data, detailed bottom-up gas-field estimates using component inventories and activity data for specific activities (e.g. number of wells drilled / year, number of unconventional well completions / year, number of unconventional well work-overs / year etc.).

The (oil and) gas industry estimates of fugitive methane emissions are then presented in total for the U.S. inventory, with total emissions by activity to a level of detail that includes:

- Unconventional gas well completions;
- Well work-overs for unconventional gas wells;
- Normal fugitives;
- Well clean-ups (LP wells);

[43] **1 cubic foot = 0.028 cubic metres**

- Pneumatic device vents.

This is the most detailed presentation of the fugitive emissions data that we have come across within a National Inventory Report, using a Tier 3 methodology using field-specific or regional gas compositional data together with documented industry methodological guidance. The level of detail in the NIR reflects the commensurate high degree of detail in installation-level reporting guidance in the U.S. for the industry over many years. The data are transparent and appear to be consistently reported across all regions. The veracity of quoted emission factors may be challenged and the reported uncertainty of estimates may remain relatively high, but the basis for the estimates is clear and detailed, and any new research to improve the emission factors would lead to direct improvements to the data.

[We note that the data in the NIR are based on emission factors that date back to earlier studies (U.S. EPA 2004, 2006) and that new emission factors have since been decided upon within the 2011 U.S. EPA GHG Reporting Protocol Sub-Part W for the oil & gas sector.]

Annex 3 of the U.S. NIR goes on to provide details of the calculation methods and emission factors used for each component, and then presents tables that summarise all of the regional gas field estimates, including emission estimates at the source-specific level, which are then aggregated up to provide the national totals for the U.S. inventory.

Section 3.4 of the Annex contains information relating to calculation of emissions from unconventional gas wells:

"Emissions for gas well completions and work overs (re-completions) with hydraulic fracturing (i.e. unconventional) (EPA 2004, 2007)…..have…been added."

Table A-120 then presents the emission factors and activity data for 2009 estimates of CH_4 emissions (in Mg) for all sub-sectors of the "Natural Gas Production Stage", including regional emission factors for methane leaks from specific components / sources, such as:

Field Separation Equipment

Heaters 15.13 scfd/heater

Separators 0.96 scfd/sep

Dehydrators 23.15 scfd/dehy

MetreMetres/Piping 9.59 scfd/metre

Gathering Compressors

Small Reciprocating Compressors 284.95 scfd/comp

Large Reciprocating Compressors 16,182 scfd/comp

Large Reciprocating Stations 8,776.43 scfd/station

Pipeline Leaks 56.57 scfd/mile

Drilling and Well Completion

Completion Flaring 780 scf/comp

Unconventional Gas Well Completions 7,694,435 scf/comp (NE)

Unconventional Gas Well Completions 7,672,247 scf/comp (midcontinent)

Unconventional Gas Well Completions 7,194,624 scf/comp (Rockies)

Unconventional Gas Well Completions 7,387,499scf/comp (SW)

Unconventional Gas Well Completions 8,429,754 scf/comp (West coast)

Unconventional Gas Well Completions 8,127,942 scf/comp (Gulf)

Well Drilling 2,706 scf/well (NE)

Well Drilling 2,699 scf/well (Midcontinent)

Well Drilling 2,531 scf/well (Rockies)

Well Drilling 2,598 scf/well (SW)

Well Drilling 2,965 scf/well (West Coast)

Well Drilling 2,859 scf/well (Gulf)

Normal Operations

Pneumatic Device Vents 367 scfd/device

Chemical Injection Pumps 264 scfd/pump

Well Workovers

Conventional Gas Wells 2,612 scf/w.o

Unconventional Gas Wells 7,694,435 scf/w.o (NE)

Well Clean Ups (LP Gas Wells) 1,361,786scfy/LP well

A2.2.2 Information from the Canada NIR, 1990-2009

Section 3.3.2 of the NIR presents the overview of fugitive emissions from the Oil and Natural gas category (IPCC 1B2). Fugitive emissions are based on a 2005 study by the Canadian Association of Petroleum Producers (CAPP): "*A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*".

In Section 3.3.2.2, the NIR states that:

"For the year 2000, emissions were identified at the facility level for over 5000 facilities. These estimates were then extrapolated to approximately 370 000 primary sources from flaring, venting, equipment leaks, formation CO_2 venting, storage losses, loading / unloading losses and accidental releases.

Natural gas systems, gas production and gas processing are considered to be part of the upstream petroleum industry, and the emissions for these sections were included. A multitude of data were collected and used in the study. These included activity data from the facilities, such as process and equipment data. Emission factors were obtained from a variety of sources: published reports, such as the U.S. EPA (1995a, 1995b); equipment manufacturers' data; observed industry values; measured vent rates; simulation programs; and other industry studies. The 1990–1999 and 2001–2009 fugitive emissions were estimated using annual industry activity data from conventional UOG production and the 2000 emission results."

Annex 3.1 of the Canada NIR presents more information on the estimation methodology for fugitive releases. The methodology for the 2000 estimates is described thus:

"The 2000 UOG emissions estimates were developed using a bottom-up approach, beginning with individual facilities and their equipment. To fulfil this, the study drew on official data from the producing provinces, supplemented by survey information on 1500 facilities provided by oil and gas producers. The following fugitive emissions sources were estimated:

- *flaring;*
- *formation CO_2, releases;*
- *venting; and*
- *fugitive and other unintentional releases (equipment leaks, storage and handling losses, and accidental releases).*

The resulting emissions were then aggregated to determine overall emissions by facility type, activity type and geographic area. The basic methods used to estimate GHG emissions are the following:

- *emission monitoring results;*
- *emission source simulation results;*
- *emission factors; and*
- *destruction and removal efficiencies.*

The following data was collected from the facilities and used to develop the 2000 inventory:

- *measured volumes of natural gas taken from the process;*
- *vented and flared waste gas volumes;*

• fuel purchases (propane, diesel fuel, etc.);

• fuel analyses;

• emission monitoring results;

• process operating conditions that may be used to infer the work being done by combustion devices (gas compositions, temperatures, pressures and flows, etc.); and

• spill and inspection reports.

Other required data included the following:

• types of processes being used;

• equipment inventories;

• emission source control features;

• sulphur content of the fuels consumed and waste gas flared; and

• composition of the inlet and outlet streams."

The methodology for the 2001-2009 estimates, drawing on the 2000 estimates as its basis, and applying scaling factors for specific activities, is described thus:

"Emissions for 2001 to 2009 were estimated by extrapolating the 2000 UOG emission data using activity data for each emission source in each subsector. There are 12 activity parametremetres for each province/territory and year; these were used to pro-rate the 2000 estimates from the UOG study for the years 2001–2009:

• gas production;

• conventional oil (CO);

• heavy oil (HO);

• crude bitumen (CB);

• fuel gas;

• flared gas;

• wells drilled;

• spills;

• total wells;

• CO + HO + CB;

• HO + CB; and

• shrinkage."

Hence the Canadian inventory approach is effectively a Tier 2 method that uses national emission factors and applies them to annual activity data, as outlined above. An on-going study due to report in 2013 is expected to overhaul the approach and look in more detail at sub-sectors of the gas E&P industry; to date, this Environment Canada study has not identified any data specific to unconventional gas E&P, however.

A2.2.3 Information from the German NIR, 1990-2009

The German NIR outlines the method for estimating upstream oil and gas emissions in Section 3.3.2.4 for natural gas, which directs the reader to the equivalent section for oil (Section 3.3.2.3) as the upstream E&P activities in Germany are not available at a level that disaggregates oil for gas production.

The NIR states that:

"emissions consist of emissions from activities of drilling companies and of other participants in the exploration sector. Gas and oil exploration takes place in Germany. In 2009, 17 successful drilling operations, with a total drilling distance of 66,201 m, were carried out (the annual report of the WEG association of oil and gas producers (Wirtschaftsverband Erdöl- und Erdgasgewinnung - WEG 2010):

Table on drilling success, p. 58). The underlying exploration statistics do not differentiate between drilling for oil and drilling for gas."

Emission estimates from drilling and oil and gas production are based on international factors from IPCC guidance, and is hence are Tier 1 methods. However, an external assessment (Muller-BBM, 2009) conducted a source category analysis and determined that the international factors are applicable to Germany, and we note that there is an on-going study in Germany to further refine and improve the oil and gas sector GHG emission estimates, which is expected to inform national estimates in the 1990-2011 inventory submission in April 2013.

A2.2.4 Information from the Polish NIR, 1990-2009

The Poland NIR provides very limited insight into the estimation methods for gas E&P sources, and no information specific to unconventional gas E&P. Section 3.9.2.2 outlines the emission estimates from fugitive sources in the natural gas E&P sector. The NIR states that:

"Estimation of CO_2 and CH_4 emissions from systems of high-methane and nitrified natural gases was carried out based on Tier 1 method [IPCC 2000]. Activity data for 1990-2009 come from [EUROSTAT]. For year's 1988-1989 activity data come from [IEA] database…. Emission factors for both gas systems were taken from country study [Steczko K. 1994] for production, processing and distribution and from [Steczko 2003] for transmission and underground storage (only CH_4)."

Table 3.9.4 then provides the emission factors for methane emissions from natural gas E&P sources in the high-methane gas system in Poland, which includes:

- 0.1008 Gg/PJ for gas production
- 0.0551 Gg/PJ for gas transmission
- 0.0014 Gg/PJ for underground gas storage; and
- 0.3099 Gg/PJ for gas distribution

The data presentation is therefore not very detailed and provides very little transparency to the emission estimates.

A2.3 IPCC GUIDELINES

The summary of IPCC guidance and its coverage / applicability to shale gas E&P sources is included within the main body of the report. In this annex, we have merely summarised the main relevant sections of the IPCC guidance documents.

The text below outlines the main sources of emissions, gives top-level guidance on estimation methods, but then goes on to detail the type of activity data that are needed to facilitate a "Tier 3" estimation method, which is the most rigorous type of method that sues installation-specific data and is subject to lower uncertainty than more generic industry-wide estimation methods that may use either country-specific emission factors ("Tier 2") or even international default emission factors ("Tier 1" methods, which are the most uncertain approach to compiling national inventory estimates).

The IPCC guidelines also provide default emission factors on the basis of volume of gas produced, for **conventional** gas extraction, covering (i) fugitives and (ii) flaring from all gas production. Uncertainty is cited as +/-100%, even for conventional gas E&P sources. Emission factors are also provided for: gas processing, gas transmission and storage, gas distribution.

[Note that we have also consulted with the lead author of the 2006 IPCC GL chapter on fugitive emissions from energy sector, and also the lead author of the relevant chapter in the 2000 Good Practice Guidance (Dave Picard of Clearstone Engineering, Canada), and he has confirmed that there are currently no default factors available for sources specific to unconventional gas E&P such as well completions.]

2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 (Energy), Chapter 4 (Fugitive emissions), Section 4.2: Natural Gas Systems

When determining fugitive emissions from oil and natural gas systems it may, primarily in the areas of production and processing, be necessary to apply greater disaggregation than is shown in Table 4.2.1 to account better for local factors affecting the amount of emissions (i.e., reservoir conditions, processing / treatment requirements, design and operating practices, age of the industry, market access, regulatory requirements and the level of regulatory enforcement), and to account for changes in activity levels in progressing through the different parts of the system. Some examples of the *potential distribution of fugitive emissions by subcategory are provided in the API (2004) Compendium.*

The sources of fugitive emissions on oil and gas systems include, but are not limited to, equipment leaks, evaporation and flashing losses, venting, flaring, incineration and accidental releases (e.g., pipeline dig-ins, well blow-outs and spills). While some of these emission sources are engineered or intentional (e.g., tank, seal and process vents and flare systems), and therefore relatively well characterised, the quantity and composition of the emissions is generally subject to significant uncertainty. This is due, in part, to the limited use of measurement systems in these cases, and where measurement systems are used, the typical inability of these to cover the wide range of flows and variations in composition that may occur. Even where some of these losses or flows are tracked as part of routine production accounting procedures, there are often inconsistencies in the activities which get accounted for and whether the amounts are based on engineering estimates or measurements. Throughout this chapter, an effort is made to state the precise type of fugitive emission source being discussed, and to only use the term fugitive emissions or fugitive emission sources when discussing these emissions or sources at a higher, more aggregated, level.

TABLE 4.2.1 DETAILED SECTOR SPLIT FOR EMISSIONS FROM PRODUCTION AND TRANSPORT OF OIL AND NATURAL GAS

1 B 2 b Natural Gas

Comprises emissions from venting, flaring and all other fugitive sources associated with the exploration, production, processing, transmission, storage and distribution of natural gas (including both associated and non-associated gas).

1 B 2 b i Venting

Emissions from venting of natural gas and waste gas/vapour streams at gas facilities.

1 B 2 b ii Flaring

Emissions from flaring of natural gas and waste gas/vapour streams at gas facilities.

1 B 2 b iii All Other

Fugitive emissions at natural gas facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, gas migration to the surface around the outside of wellhead casing, surface casing vent bows and any other gas or vapour releases not specifically accounted for as venting or flaring.

1B 2 b iii 1 Exploration

Fugitive emissions (excluding venting and flaring) from gas well drilling, drill stem testing and well completions.

1B 2 b iii 2 Production

Fugitive emissions (excluding venting and flaring) from the gas wellhead through to the inlet of gas processing plants, or, where processing is not required, to the tie-in points on gas transmission systems. This includes fugitive emissions related to well servicing, gas gathering, processing and associated waste water and acid gas disposal activities.

1 B 2 b iii 3 Processing

Fugitive emissions (excluding venting and flaring) from gas processing facilities.

1 B 2 b iii 4 Transmission and Storage

Fugitive emissions from systems used to transport processed natural gas to market (i.e., to industrial consumers and natural gas distribution systems). Fugitive emissions from natural gas storage systems should also be included in this category. Emissions from natural gas liquids extraction plants on gas transmission systems should be reported as part of natural gas processing (Sector 1.B.2.b.iii.3). Fugitive emissions related to the transmission of natural gas liquids should be reported under Category 1.B.2.a.iii.3

1 B 2 b iii 5 Distribution

Fugitive emissions (excluding venting and flaring) from the distribution of natural gas to end users.

1 B 2 b iii 6 Other

Fugitive emissions from natural gas systems (excluding venting and flaring) not otherwise accounted for in the above categories. This may include emissions from well blowouts and pipeline ruptures or dig-ins.

Fugitive emissions from oil and natural gas systems are often difficult to quantify accurately. This is largely due to the diversity of the industry, the large number and variety of potential emission sources, the wide variations in emission-control levels and the limited availability of emission-source data. The main emission assessment issues are:

• The use of simple production-based emission factors introduces large uncertainty;

• The application of rigorous bottom-up approaches requires expert knowledge and detailed data that may be difficult and costly to obtain;

• Measurement programmes are time consuming and very costly to perform.

The ability to use a Tier 3 approach will depend on the availability of detailed production statistics and infrastructure data (e.g. information regarding the numbers and types of facilities and the amount and type of equipment used at each site), and it may not be possible to apply it under all circumstances. Where a country has estimated fugitive emissions from oil and gas systems based on a compilation of estimates reported by individual oil and gas companies, this may either be a Tier 2 or Tier 3 approach, depending on the actual approaches applied by individual companies and facilities.

On a small scale, fugitive emissions are completely independent of throughput. The best relation for estimating emissions from fugitive equipment leaks is based on the number and type of equipment components and the type of service, which is a Tier-3 approach.

TIER 3

Tier 3 comprises the application of a rigorous bottom-up assessment by primary type of source (e.g., venting, flaring, fugitive equipment leaks, evaporation losses and accidental releases) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. It should be used for key categories where the necessary activity and infrastructure data are readily available or are reasonable to obtain. Tier 3 should also be used to estimate emissions from surface facilities where EOR, EGR and ECBM are being used in association with CCS. Approaches that estimate emissions at a less disaggregated level than this (e.g., relate emissions to the number of facilities or the amount of throughput) are deemed to be equivalent to a Tier 1 approach if the applied factors are taken from the general literature, or a Tier 2 approach if they are country-specific values.

The key types of data that would be utilized in a Tier 3 assessment would include the following:

- *Facility inventory, including an assessment of the type and amount of equipment or process units at each facility, and major emission controls (e.g., vapour recovery, waste gas incineration, etc.).*
- *Inventory of wells and minor field installations (e.g., field dehydrators, line heaters, well site metreing, etc.).*
- *Country-specific flare, vent and process gas analyses for each subcategory.*
- *Facility-level acid gas production, analyses and disposition data.*
- *Reported atmospheric releases due to well blow-outs and pipeline ruptures.*
- *Country-specific emission factors for fugitive equipment leaks, unaccounted/unreported venting and flaring, flashing losses at production facilities, evaporation losses, etc.*
- *The amount and composition of acid gas that is injected into secure underground formations for disposal.*

TABLE 4.2.6 TYPICAL ACTIVITY DATA REQUIREMENTS FOR EACH ASSESSMENT APPROACH FOR FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS BY TYPE OF PRIMARY SOURCE CATEGORY

Process Venting / Flaring

Reported Volumes, Gas Compositions, Proration Factors for Splitting Venting from Flaring.

Storage Losses

Solution Gas Factors, Liquid Throughputs, Tank Sizes, Vapour Compositions.

Equipment Leaks

Facility / Installation Counts by Type, Processes Used at Each Facility, Equipment Component Schedules by Type of Process Unit, Gas/Vapour Compositions.

Gas-Operated Devices

Schedule of Gas-operated Devices by Type of Process Unit, Gas Consumption Factors, Type of Supply Medium, Gas Composition.

Accidental Releases & Third-Party Damages

Incident Reports / Summaries.

Gas Migration to the Surface & Surface Casing Vent Blows

Average Emission Factors & Numbers of Wells.

Drilling

Number of Wells Drilled, Reported Vented / Flared Volumes from Drill Stem Tests, Typical Emissions from Mud Tanks.

Well Servicing

Tally of Servicing Events by Types.

Pipeline Leaks

Type of Piping Material, Length of Pipeline.

Exposed Oils ands / Oil Shale

Exposed Surface Area, Average Emission Factors.

Venting and Flaring from Oil Production

Gas to Oil Ratios, Flared and Vented Volumes, Conserved Gas Volumes, Re-injected Gas Volumes

Utilised Gas Volumes, Gas Compositions.

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